Transportation Electrification Distribution System Impact Study

Final Report | Report Number 22-13 | May 2022

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Advance clean energy innovation and investments to combat climate change, improving the health, resiliency, and prosperity of New Yorkers and delivering benefits equitably to all.

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Transportation Electrification Distribution System Impact Study

Final Report

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Abstract

This report examines technical and economic factors in order to estimate the load and cost impacts of various clean transportation futures considered in the New York Clean Transportation Roadmap on New York State's electric distribution system.

Keywords

Electric vehicles, charging infrastructure, charging load, load profiles, peak demand, managed charging, energy efficiency, utilities, grid infrastructure, distribution system, circuits, networks, transportation electrification, building electrification, energy storage, capital costs

Acknowledgement

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Acronyms and Abbreviations

BE	Building Electrification
BTM	Behind the Meter
CHGE	Central Hudson Gas & Electric, Inc.
Climate Act	Climate Leadership and Community Protection Act
Con Ed	Consolidated Edison of New York, Inc.
CTR	Clean Transportation Roadmap
DER	Distributed Energy Resources
EE	Energy Efficiency
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
GHG	Greenhouse Gas
HDI	High-Distribution System Impact
HTA	High-Technology Availability
LDI	Low-Distribution System Impact
LDV	Light Duty Vehicle
LNE	Limited Non-Energy
MHDV	Medium and Heavy-Duty Vehicle
NG	National Grid, Inc.
NPV	Net Present Value
NYISO	New York Independent System Operator
NYSEG	New York State Electric and Gas Corporation
O&R	Orange & Rockland Utilities, Inc.
O&M	Operations and Maintenance
PSEG-LI	Public Service Enterprise Group-Long Island
PV	Photovoltaic Solar
PVL	Poly Voltage Loadflow
RGE	Rochester Gas & Electric Company
TEDI	Transportation Electrification Distribution System Impact
TE	Transportation Electrification

Executive Summary

The primary objective of the study was to estimate the cost impact of various clean transportation futures considered in the New York Clean Transportation Roadmap (the Roadmap or "CTR") on New York State's electric distribution system. The scenarios for the Transportation Electrification Distribution System Impact (TEDI) study were developed to meet the objective of providing a range for, or bookending, the distribution upgrade costs associated with various clean transportation futures. Two main policy scenarios were developed for this study—High-Distribution System Impact (HDI) scenario and Low-Distribution System Impact (LDI) scenario. In addition, a reference scenario was also developed. All scenarios were analyzed with and without managed electric vehicle (EV) charging. The assumptions regarding transportation electrification for these three study scenarios came from the Clean Transportation Roadmap that was developed as part of a separate study performed by Cadmus. The assumptions regarding end-use load growth, energy efficiency, photovoltaic (PV) solar, energy storage, and building electrification for the policy scenarios were derived from the Pathways to Deep Decarbonization in New York State (Pathways Study) performed by E3 for the HDI and LDI scenarios. The same set of assumptions for the reference scenario were derived from the New York ISO Gold Book.

For this TEDI study, the impact of transportation electrification on radial distribution systems was analyzed using the typical configuration of these systems, as found in National Grid's system. The impact on the secondary network distribution system was studied using Con Edison's system. Twenty-seven representative circuits and substation configurations in National Grid's service territory and five representative networks in Con Edison's service territory were studied under the scenarios described previously. The upgrade costs obtained from this analysis were then extrapolated to obtain the costs for all of New York State.

The key results of the study are the estimated net present values (NPV) of New York State's distribution system upgrade costs due to transportation electrification for each five-year period between 2020 and 2050 and the associated operations and maintenance (O&M) costs for each five-year period between 2020 and 2095. The costs estimated in this study (to support an increase in capacity) include the cost of upgrading or adding new circuits, transformer banks, and substations. The costs associated with segment-level upgrades (distribution system components downstream from the distribution substation and the main feeder leaving the substation), voltage regulation equipment, and the replacement of distribution transformers are also included. The costs of the electric vehicle supply equipment (EVSE) themselves and the costs associated with connecting them to the grid are not included. Only State-level costs are presented in this report since the objective of the study was to obtain a high-level estimate of the distribution cost impact using a long-term economic model.

The NPV of New York State's distribution system upgrade costs due to transportation electrification range from $1.4 billion in the LDI Managed EV charging case to $26.8 billion in the HDI Unmanaged case. It can be observed from the results that the distribution upgrade costs were significantly lower with managed EV charging—61 percent and 46 percent of the unmanaged case for HDI and LDI scenarios, respectively, showing that managed charging could play a signification factor in lowering the distribution upgrade costs. An analysis was performed by Cadmus on how the distribution costs impact the adoption of EVs using the incremental costs developed in the TEDI study. Based upon this analysis, Cadmus concluded that the additional distribution costs are not likely to be a significant factor in the adoption of EVs.

1 Background and Study Objectives

1.1 Background

In 2019, Governor Andrew M. Cuomo signed the Climate Leadership and Community Protection Act (Climate Act) into law, setting the State's greenhouse gas (GHG) emissions limit to 40 percent of 1990 levels by 2030 and 85 percent below 1990 levels by 2050. The Climate Act comes at a time of rapid change in the transportation sector, characterized by new powertrains, fuels, and mobility options, as well as a growing recognition of the inequalities created by the transportation system. Amidst this backdrop, transportation continues to be one of the largest sources of emissions of any sector, at 37 percent of the New York State total (NYSERDA 2019).

The New York State Clean Transportation Roadmap (the "Roadmap") summarizes the current state of the State's transportation system and explores options for decarbonization, highlighting barriers, rates of technology adoption, GHG emissions, and policy impacts. The Roadmap covers all sub-sectors within transportation, including light-duty vehicles (LDVs), medium- and heavy-duty vehicles (MHDVs), aviation, rail, marine, and non-road.

As indicated in the Roadmap, even with significant current policy leadership, State, and local investments, as well as an active entrepreneurial sector, the transportation sector still faces substantial barriers to decarbonization. Therefore, the Roadmap presents four mitigation cases that help describe distinct, viable pathways for transportation decarbonization in the State. Each mitigation case explores different levels of regulation, price-based signals, market-enabling financing, support for new products and business models, mandates and targets, and outreach and education. Aside from their comparable projected GHG emissions, each scenario generates notable differences in its impacts on cost, criteria pollutants, technology risk, equity, social benefits, and other important societal outcomes in the Roadmap. One such outcome is the effect on the electric distribution system, the subject of the Transportation Electrification Distribution System Impact (TEDI) study (the Study) presented here.

1.2 Objectives

The primary objective of the TEDI study is to estimate the impact of clean transportation futures considered in the Roadmap on New York State's electric distribution systems. The adoption of electric vehicles will result in an increase in loading on the electric distribution system and will require upgrades to the distribution system in many cases to increase its capacity. A clean transportation future that includes a greater role for electrification is expected to have a bigger impact on the distribution system than one that includes a greater role for hydrogen as a source of energy. The purpose of the study is to bookend the capacity-related distribution system upgrade costs due to transportation electrification based on various possible futures.

Most distribution upgrade costs will need to be recovered by the utility through its rates. The increase in rates due to the distribution upgrades has the potential to impact the adoption of electric vehicles. Another objective of this study is to inform the Roadmap on the electricity rate impact associated with the mitigation cases to better understand how potential rate increases may impact EV adoption.

A utility's rates related to distribution include capital, operations, and maintenance costs for a variety of different purposes including, for example, capital projects to meet needs such as asset management, reliability, resiliency, grid modernization, line extensions to serve single customers, capacity shortages, safety and compliance, etc. Rates also include cost for the overall operation of the distribution grid, control center costs, field crews, contract crews. etc. It should be noted that this study focuses *only* on distribution upgrades and associated incremental operations and maintenance (O&M) due to increased capacity needs driven by load growth and does not include any of the other needs mentioned above. There may also be other costs associated with electric vehicles, such as connecting them to the distribution grid, cost of EV-related upgrades made on the customer side of the meter etc., which are not estimated in this study.

2 Study Approach

This section presents the approach used for estimating the impact of several potential transportation electrification futures on New York State's electric distribution system. The overall approach is to simulate the planning processes followed by the utilities to estimate the approximate costs of distribution system upgrades due to EV load growth. Since it is a long-term economic study, it does not replicate the exact planning processes typically used or dealing with the granularity that short-term distribution planning must consider.

2.1 Scenario-Based Analysis

The impact of transportation electrification on the distribution system cannot be studied in isolation. There are several factors that impact the loading of the distribution system including future end use, load-growth projections, energy efficiency forecasts, distributed energy resources (such as PV solar and energy storage) and building electrification. While some of these factors might result in additional load on the distribution system, others may alleviate the load. For example, the increase in loading due to transportation electrification can be offset by higher adoption of energy efficiency or energy storage. Therefore, it's important to study the cumulative effects of all factors on the distribution system in order to get as clear a picture as possible of the distribution impacts due to transportation electrification. For this study, two key scenarios were examined—the High-Distribution System Impact and the Low-Distribution System Impact scenarios, in addition to the reference scenario. The scenarios included a combination of assumptions that would either result in high- or low-distribution system loading so as to bookend the distribution upgrade costs. These scenarios are discussed in detail in section 3.

2.2 Representative Distribution System Circuits and Networks

New York State's investor-owned utilities distribute electricity to end users and are responsible for operating and maintaining their respective electric service distribution systems. Seven utilities own and operate the distribution system in New York State. They are Central Hudson Gas & Electric, Inc. (CHGE), Consolidated Edison of New York, Inc. (Con Ed), National Grid, Inc. (NG), New York State Electric and Gas Corporation (NYSEG), Orange & Rockland Utilities, Inc. (O&R), Rochester Gas & Electric Company (RGE) and Public Service Enterprise Group-Long Island (PSEG-LI).

These distribution systems are designed as either radial or network systems. Radial distribution systems consist of a number of primary circuits extending radially from a substation connected to the bulk power transmission system. In a network distribution system, parallel lower voltage feeder cables, network transformers, and protective relays are used for a more redundant system frequently found in high-load density metropolitan areas. In New York, the majority of the State is served using radial distribution systems while New York City is served using an underground secondary network system.

For this study, the impact of transportation electrification on radial distribution systems was studied using the typical configuration of these systems, as found in National Grid's distribution system. The impact on secondary network distribution systems was studied using Con Edison's network. The methodology used for studying the impacts for National Grid and Con Edison are presented in sections 4 and 5, respectively.

2.3 Extrapolation of Results to New York State

As mentioned earlier, the radial distribution system configurations found in Upstate New York utilities, such as National Grid, and secondary network distribution systems found in Con Edison's service territory were studied by analyzing the impact of transportation electrification. Another point to note is that not all the circuits in these two utilities were studied. Rather, representative circuits and networks were used to study the impact. As such, there are two extrapolations made in this study—one to extrapolate the results of representative circuits and networks to the utility service territory, that is, National Grid and Con Edison, and the other to extrapolate the results of these two utilities to the rest of New York State. The extrapolation methodology employed for the two utilities for developing utility-level costs is discussed in sections 4 and 5. The extrapolation methodology used for developing State-level costs is discussed in section 6.

2.4 Key Deliverables

The key deliverables of the study are the net present value (NPV) of New York State's distribution system upgrade costs due to transportation electrification for each five-year period between 2020 and 2050 and the associated operations and maintenance (O&M) costs for each five-year period between 2020 and 2095. The costs estimated include the cost of upgrading or adding new circuits, transformer banks, and substations. The costs associated with segment-level upgrades (distribution system components downstream from the distribution substation and the main feeder leaving the substation), voltage regulation equipment, and the replacement of distribution transformers are also included. The costs of the electric vehicle supply equipment (EVSE) themselves and the costs associated with connecting them to the grid are not included.

3 Scenario Development

This section presents the scenarios that were developed for the study. Section 3.1 provides a high-level overview of the scenarios, the data sources, and alignment with other studies. Sections 3.2 through 3.4 provide detailed information on the policy scenarios and the reference scenario developed for this study.

3.1 Development of Scenarios

The scenarios for the TEDI study were primarily developed to meet the objective of bookending the distribution upgrade costs associated with various clean transportation futures. Two policy scenarios were developed—a High-Distribution System Impact (HDI) scenario and a Low-Distribution System Impact (LDI) Scenario. In addition, a reference scenario was also developed.

The assumptions regarding transportation electrification for all the study scenarios came from the Clean Transportation Roadmap study performed by Cadmus. The assumptions regarding end-use load growth, energy efficiency, photovoltaic (PV) solar, energy storage, and building electrification were derived from the Pathways to Deep Decarbonization in New York State (Pathways Study) performed by E3 for the policy scenarios and the New York Independent System Operator (NYISO) Gold Book for the reference scenario. The Gold Book was used for the reference scenario since the reference case assumptions in the Pathway Study were undergoing modifications during the time the TEDI study started. Table 1 summarizes the sources of assumptions for the various study scenarios. The assumptions listed in this table are explained in greater detail in sections 3.1.1 and 3.1.2.

Section 3.1.1 discusses the assumptions and scenarios developed for transportation electrification in the Clean Transportation Roadmap study. Sections 3.1.2 and 3.1.3 provide more information on the assumptions and scenarios developed in the Pathways Study and the NYISO Gold Book. Detailed assumptions for each TEDI study scenario can be found in sections 3.2 through 3.4. Information on how these high-level assumptions are translated to circuit and network level assumptions for National Grid and Con Edison can be found in sections 4 and 5.

Table 1. Study Scenario Assumptions

	Reference Scenario	High-Distribution System Impact Scenario	Low-Distribution System Impact Scenario
End Use Load Growth	Baseline Forecast from 2020 NYISO Gold Book	LNE Forecast from the Pathways Study	HTA Forecast from the Pathways Study
Energy Efficiency	Baseline Forecast from 2020 NYISO Gold Book	LNE Forecast from the Pathways Study	HTA Forecast from the Pathways Study
BTM Solar PV	Baseline Forecast from 2020 NYISO Gold Book	LNE Forecast from the Pathways Study	HTA Forecast from the Pathways Study
BTM Energy Storage	Baseline Forecast from 2020 NYISO Gold Book	LNE Forecast from the Pathways Study	HTA Forecast from the Pathways Study
Transportation Electrification	Reference Case Forecast from CTR	Mitigation 1 Forecast from CTR	Mitigation 4 Forecast from CTR
Building Electrification	Low-Load Forecast from 2020 NYISO Gold Book	LNE Forecast from the Pathways Study ("No Flex" Building Electrification)	HTA Forecast from the Pathways Study

3.1.1 Clean Transportation Roadmap

The Roadmap presents four mitigation cases that help describe distinct, viable pathways for transportation decarbonization in the State. The mitigation cases were developed to meet the various sets of policies that can be implemented by State and/or local authorities to meet the transportation related GHG emission reductions necessary under the Climate Act. The four mitigation scenarios vary along two axes, reflecting differing dominant fuel switching technologies and level of emphases on strategies to manage vehicle miles traveled (VMT) and encourage mode shift. The TEDI study departs from the approach used in the Roadmap due to its focus on two of the four mitigation cases (mitigation 1 and 4) that are anticipated to define the upper and lower bounds in distribution system impacts. The scenarios differ in the dominant technology, comparing a focus on electrification versus a more balanced approach between electrification and hydrogen strategies, and in level of emphasis on VMT management and mode shift strategies. While the mitigation cases differ in their emphasis on certain policies, they are equally consistent with the State's emission targets and result in similar potential emission reductions in future years.

Mitigation Case 1 illustrates a technology emphasis on electrification paired with moderate VMT and mode shift policies.

Fuel-switching & efficiency	**Near-term (2020-2030)** • **Rebates, incentives, and sales targets** for automakers combine to make electric LDVs price competitive with Internal Combustion Engine vehicles (ICEVs) very soon. • Public investment supports **very expansive deployment of EVSE**, including in areas that are underserved by the private market, enabling near-immediate transition in consumer purchase choices. • **A clean fuel standard and a higher carbon price that consistently increases** build demand for all low-carbon fuels, spurring investment and development of production capacity and delivery infrastructure. **Medium-term (2030-2050)** • Market actors leverage experience with LDV electrification to catalyze MHDV electrification. • Equipment standards require that half of all short-haul flights and half of all non-road vehicles be electric. • **Subsectors that cannot easily be electrified** due to technology availability, cost, or the use cases of the vehicles, such as long-range freight and long-haul aviation, **switch to low-carbon liquid fuels**.
VMT management & mode shift	**Near-term (2020-2030)** • Investments in pedestrian and bike infrastructure and expanded transit service affect mode choices, driving some shifts towards use of public transit and active transportation. • Smart Growth principles are embedded in land use decisions throughout the State. **Medium-term (2030-2050)** • The accumulation of local planning decisions favoring mixed-use and transit-oriented development begin to manifest in reduced trip distances, as people and goods need to move shorter distances to destinations. • **A higher carbon price discourages unproductive trips** across all fuel types, reducing total travel demand.

Mitigation Case 4 illustrates a mixed technology emphasis that includes electrification and hydrogen, with a more aggressive set of VMT and mode shift policies.

Fuel-switching & efficiency	**Near-term (2020-2030)** • Generous rebates and incentives combine to make hydrogen fuel cell and electric LDVs price competitive with ICEVs. • Public investment supports substantial availability of hydrogen infrastructure and moderate deployment of EVSE, enabling transition in consumer purchase choices. • **A moderate clean fuel standard and a modest carbon price** provide revenue streams and reduce the cost of low-carbon fuels, spurring investment and development of production capacity and delivery infrastructure. **Medium-term (2030-2050)** • Equipment standards spur half of medium-duty, and all heavy-duty vehicles convert to HFCEVs and require that half of all short-haul flights be fueled by hydrogen.
VMT management & mode shift	**Near-term (2020-2030)** • Investments in pedestrian and bike infrastructure and expanded transit service affect mode choices, driving **unprecedented shifts towards use of public transit and active transportation.** • **Smart Growth principles are at the center of state transportation planning,** funding mechanisms are restructured to align with these principles, and funds are invested aggressively in projects that realize this new land use approach. **Medium-term (2030-2050)** • The State's focus on mixed-use and transit-oriented development manifests in reduced trip distances, as people and goods need to move shorter distances to destinations. • **A moderate carbon price discourages some low-value trips** across all fuel types, reducing total travel demand.

The Roadmap also presents a reference case that addresses a central question: how will the transportation sector develop over the coming decades without additional policy interventions? In the reference case, modeling suggests electric vehicles will account for 32 percent of new LDV sales in 2030 and 64 percent in 2050. This moderate electrification, along with other shifts, leads to a 28 percent reduction in GHG emissions in 2050, relative to 1990 levels. As a result, the reference case does not achieve the Climate Act goals.

3.1.2 Pathways Study

The Pathways Study (Pathways to Deep Decarbonization in New York State) conducted by Energy and Environmental Economics (E3) evaluated the emission impact of New York State's recent policies and explored additional measures that would be needed to reach the State's 2030 and 2050 Climate Act goals. Although this study captured economy wide GHG emissions and mitigation opportunities, its analytic focus was on the electricity, transportation, buildings, and industrial sectors. For this study, E3 developed the following two pathways for achieving the Climate Act's GHG emissions goals and electric sector targets.

High-Technology Availability Pathway—This pathway relies on a diverse portfolio of GHG mitigation options, including high levels of efficiency and end-use electrification, with assets retired at the end of useful lifetimes.

Limited Non-Energy Pathway—This pathway accelerates electrification and ramp-up of new equipment sales, along with early retirements of older and less-efficient fossil vehicles and building systems.

Table 2 summarizes the assumptions behind these two scenarios that have any impact on the electric distribution system.[1] A complete list of assumptions and a detailed description of these two cases can be found in the Pathways Study report.

Table 2. Pathways Study Assumptions Used in the TEDI Study

Sector	Strategy	Expressed as	High-Technology Availability	Limited Non-Energy
Buildings	Building Shell Efficiency	Efficient shell sales share	85% by 2030 100% by 2045	Same as HTA
	Building Electrification	Electric heat pump sales share	50% by 2030 95% by 2050	70% by 2030 100% by 2045*
	Appliance Efficiency (non-HVAC)	Efficient appliance sales share	90% by 2023 100% by 2025	Same as HTA
Industry	Efficiency	Efficiency increase relative to baseline projection	10% by 2030 45% by 2045	Same as HTA
	Fuel Switching	Share of natural gas and LPG use electrified	60% by 2045	Same as HTA
Clean Electricity	Clean Electricity Generation	Share of renewable/zero-emission generation	70% renewable by 2030 100% zero-emission by 2040	Same as HTA
	Technology-specific targets	Offshore wind capacity	9 GW by 2035	Same as HTA
		Behind-the-meter solar PV	6 GW by 2025	Same as HTA
		Energy Storage	3 GW by 2030	Same as HTA

3.1.3 NYISO Gold Book

The New York Independent System Operator (NYISO) publishes the Gold Book every year which contains a forecast of the load and capacity at the New York Control Area (NYCA) and NYISO zonal level for a 30-year period. In the 2020 Gold Book, the NYISO provided a baseline load forecast for the years 2020-2050. The baseline forecasts show the expected NYCA and zonal loads under expected weather conditions, and account for the load-reducing impacts of energy efficiency programs, building codes, and appliance efficiency standards, solar PV, and non-solar distributed energy generation. The baseline forecast also includes the expected impacts of electric vehicle usage and other electrification[1]. In addition to the baseline forecast, NYISO also develops low-load and high-load scenario forecasts to reflect the increasing uncertainty in energy usage over time. Table 3 shows the assumptions for these three scenarios. Additional information on the scenarios can be found in the 2020 Gold Book.

Table 3. NYISO 2020 Gold Book Assumptions Used in the TEDI Study

Forecast Component	Baseline Forecast	Low-Load Scenario	
Weather Trends	Trended Weather from NYISO Climate Change Impact Study - avg temp gain of approximately 0.7 deg F per decade	Same as baseline forecast	Same as baseline forecast
Economic Assumptions	Moderate recession due to COVID-19 impacts, followed by typical economic growth in the long run	Severe recession due to COVID-19 impacts, followed by below typical economic growth in the long run	Slight recession due to COVID-19 impacts, followed by above typical economic growth in the long run
Energy Efficiency	Medium energy efficiency gains - substantial attainment of current policy measures	High energy efficiency gains - full attainment of current policy measures	Low-energy efficiency gains - low attainment of current policy measures
BTM Solar PV	Medium BTM solar approximately 6,000 MW installed nameplate capacity by 2027	High BTM solar - 6,000 MW installed nameplate capacity by 2025	Low BTM solar - approximately 6,000 MW installed nameplate capacity by 2031
BTM Non-Solar DG	Over 200 MW installed non-solar BTM DG by 2050. Some existing BTM DG enters the wholesale DER market	Same as baseline forecast	Same as baseline forecast
Energy Storage	Approximately 3,000 MW installed nameplate capacity by 2030, with over 6,000 MW installed by 2050 (total BTM plus wholesale)	Over 7,500 MW installed nameplate capacity by 2050, with a larger proportion of storage behind-the-meter	Same as baseline forecast
Non-EV Electrification	Medium electrification - partial electrification of heating and other end uses	Low electrification - modest electrification based on anticipated short-term trend	High electrification - significant electrification of heating and other end uses

3.2 Reference Scenario

The TEDI Reference Scenario is meant to be a business-as-usual scenario primarily based on the load growth, energy efficiency, and distributed energy resources (DER) assumptions from the NYISO Gold Book Baseline forecast, except for the building electrification assumptions which are from the NYISO Gold Book, Low-Load forecast. As mentioned before, the Gold Book was used as a source for these forecasts since the forecasts in the Pathway's reference case was undergoing modifications during the time the TEDI study started. The transportation electrification assumptions are from the Clean Transportation Roadmap (CTR) Reference Case. The assumptions for the TEDI Reference Scenario are summarized in Table 1. The reference scenario was studied with and without managed EV charging, as well as without any transportation electrification (TE) loads to extract the impacts of transportation electrification alone. This is further discussed in sections 4 and 5. It should be noted that the TEDI Reference Scenario does not achieve the Climate Act goals whereas the policy scenarios do. Table 1 shows the sources for the assumptions for the TEDI Reference and policy scenarios.

Figure 1 shows the sum of end use, energy efficiency (EE), and building electrification (BE) loads for the summer and winter seasons. Figure 2 shows the behind-the-meter (BTM) PV and energy storage forecast for the study period. Figure 3 and Figure 4 show the hourly profile for unmanaged and managed EV charging for every 5th year within the study period. All of the below plots are for the reference scenario. A comparison of the hourly EV load profiles for the managed and unmanaged charging cases for each scenario is included in appendix A.

Figure 1. Sum of End-Use Load, Energy Efficiency, and Building-Electrification Load for the Reference Scenario

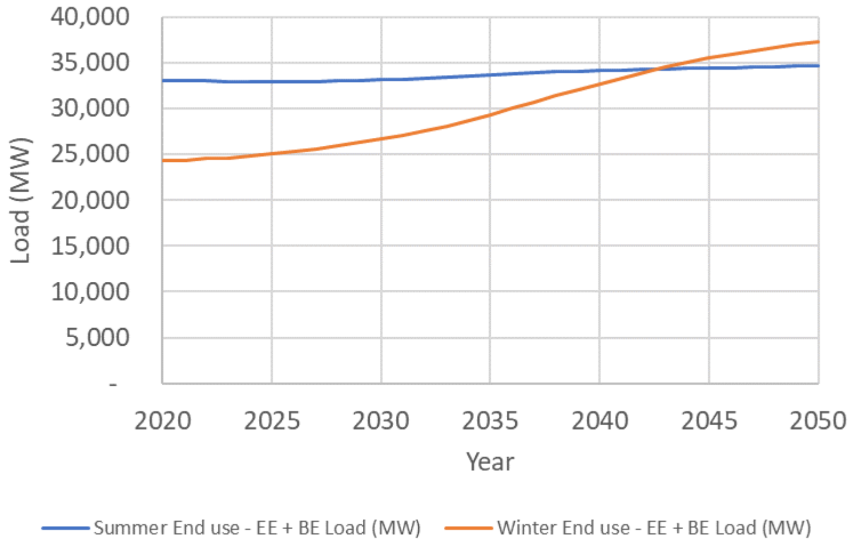


Figure 2. BTM PV and Energy Storage Capacity for the Reference Scenario

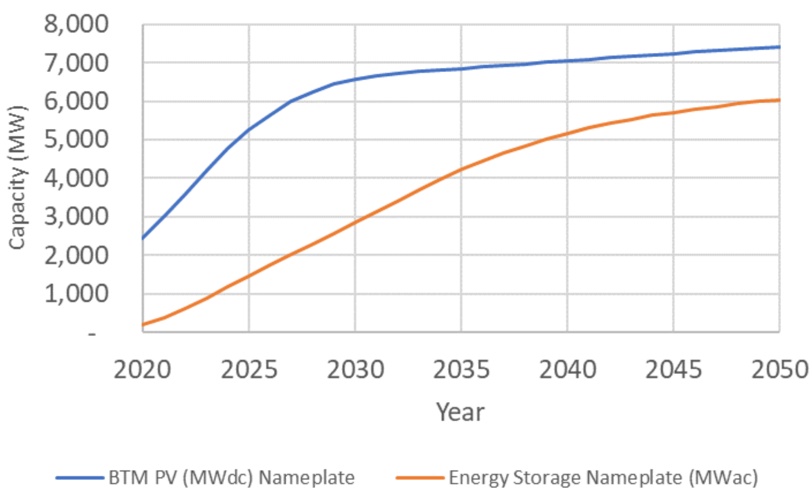


Figure 3. Unmanaged EV Charging Profile for the Reference Scenario

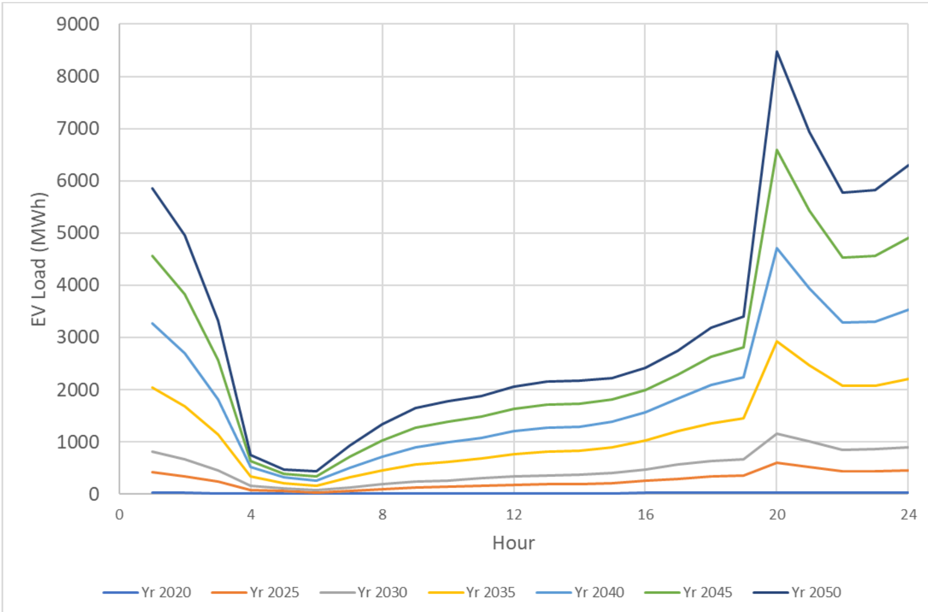
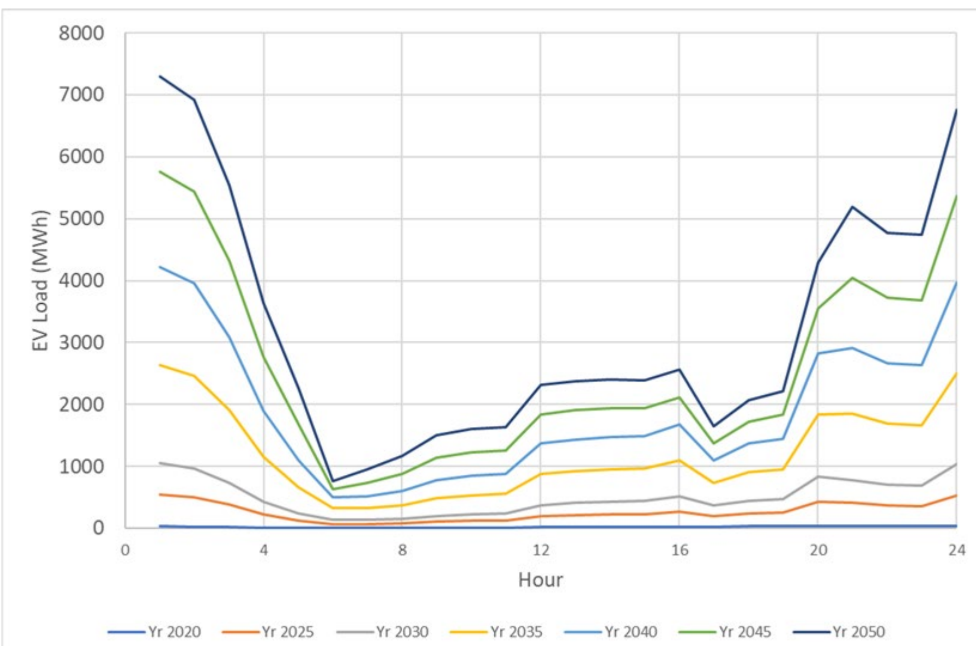


Figure 4. Managed EV Charging Profile for the Reference Scenario



3.3 High-Distribution System Impact Scenario

The TEDI High-Distribution System Impact (HDI) scenario was constructed using the Pathway's Low-Net Energy (LNE) assumptions for load growth, EE, DER, and building electrification and the transportation electrification assumptions from the CTR Mitigation 1 case. The LNE assumptions lead to higher peak load growth due to higher amounts of building electrification when compared to the HTA Case in the Pathways Study. Further, in this scenario, the load due to building electrification is also assumed to have no flexibility. It is assumed that the loads due to building electrification are not capable of being shifted to low-load hours using Time of Use (TOU) rates or other control mechanisms. This scenario also uses the assumptions from CTR's Mitigation 1 case which assumes a future with higher transportation electrification when compared with the Mitigation 4 case which assumes a greater role for hydrogen as a source of energy. The combination of assumptions in this scenario results in a peak load that is the highest and serves as the upper bookend for the distribution upgrade costs. The assumptions for the HDI scenario are summarized in Table 1. This scenario was studied with and without managed EV charging, as well as without any TE load to extract the impacts of transportation electrification alone. This is further discussed in sections 4 and 5.

Figure 5 shows the sum of end-use, energy efficiency and building-electrification loads for the summer and winter seasons. Figure 6 shows the behind-the-meter PV, and energy storage forecast for the study period. Figure 7 and Figure 8 show the hourly profile for unmanaged and managed EV charging for every 5th year within the study period. All of the below plots are for the HDI scenario.

Figure 5. Sum of End-Use Load, Energy Efficiency, and Building-Electrification Load for the HDI Scenario

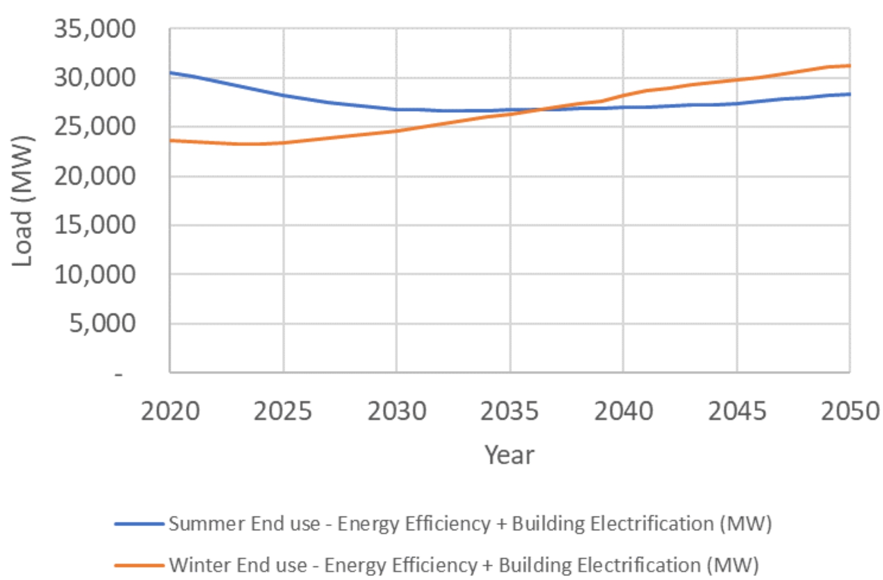


Figure 6. BTM PV and Energy Storage Capacity for the HDI Scenario

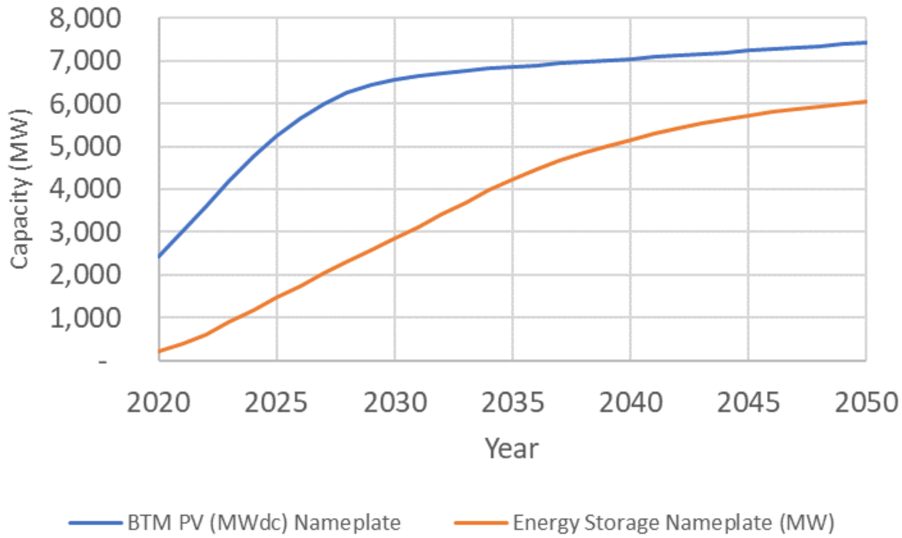


Figure 7. Unmanaged EV Charging Profile for the HDI Scenario

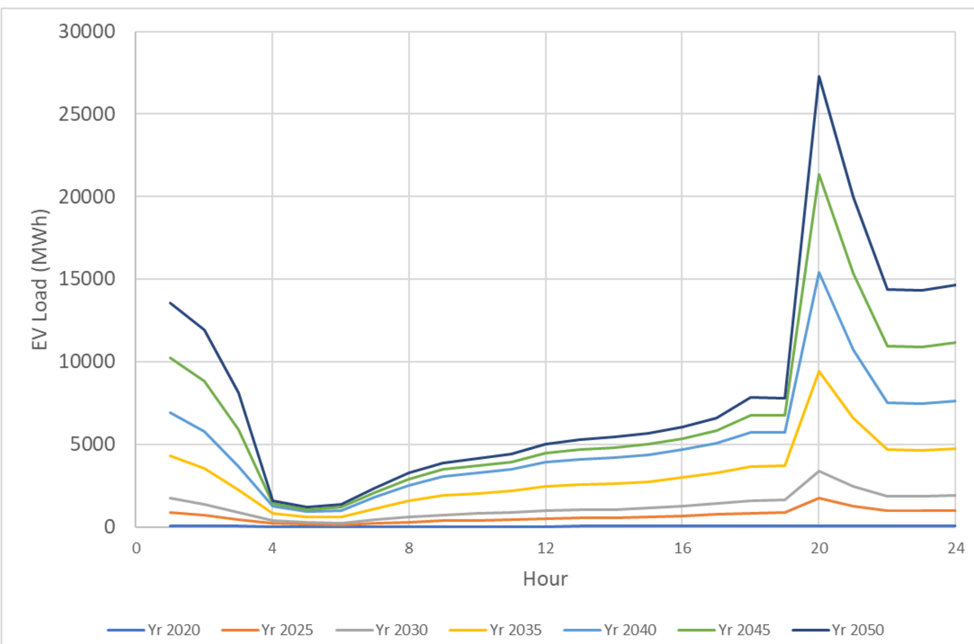
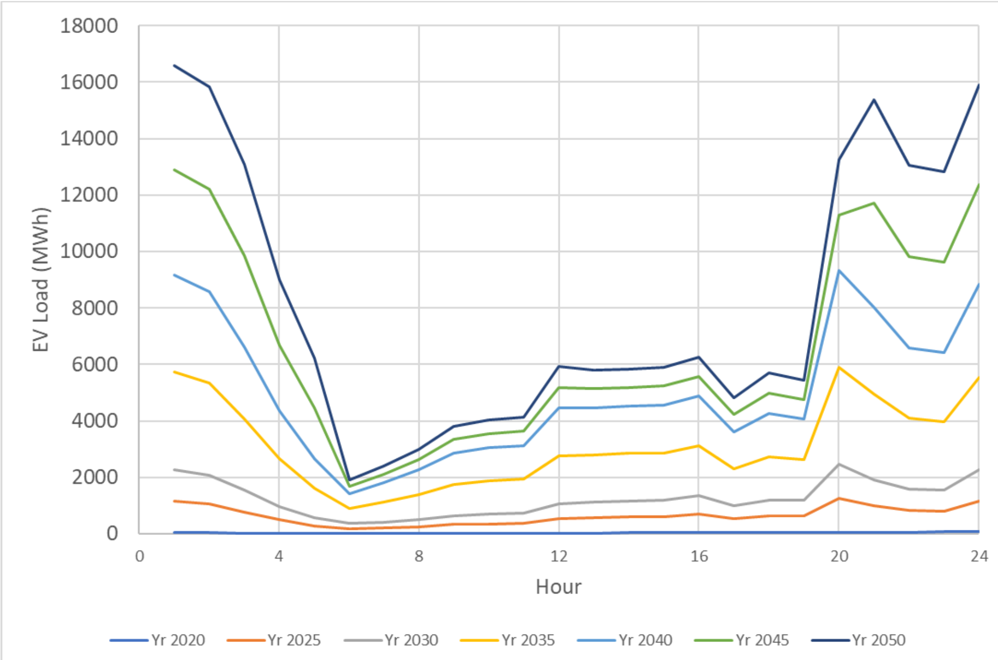


Figure 8. Managed EV Charging Profile for the HDI Scenario



3.4 Low-Distribution System Impact Scenarios

The TEDI Low-Distribution System Impact scenario was constructed using the Pathway's High-Technology Availability (HTA) assumptions for load growth, EE, DER, and building electrification and the transportation electrification assumptions from the CTR Mitigation 4 case. In this scenario, the load due to building electrification is assumed to have flexibility. It is assumed that some of the loads due to building electrification can be shifted to low-load hours using TOU rates or other control mechanisms. The combination of assumptions in this scenario results in a peak load that is the lowest and serves as the lower bookend for the distribution upgrade costs. The assumptions for the Low-Distribution System Impact scenario are summarized in Table 1. This scenario was studied with and without managed charging, as well as without any TE load to extract the impacts of transportation electrification alone. This is further discussed in sections 4 and 5.

Figure 9 shows the sum of end-use, energy efficiency, and building-electrification loads for the summer and winter seasons. Figure 10 shows the behind-the-meter PV and energy storage forecast for the study period. Figure 11 and Figure 12 show the hourly profile for unmanaged and managed EV charging for every 5th year within the study period. All of the below plots are for the LDI Scenario.

Figure 9. Sum of End-Use Load, Energy Efficiency and Building-Electrification Load for the LDI Scenario

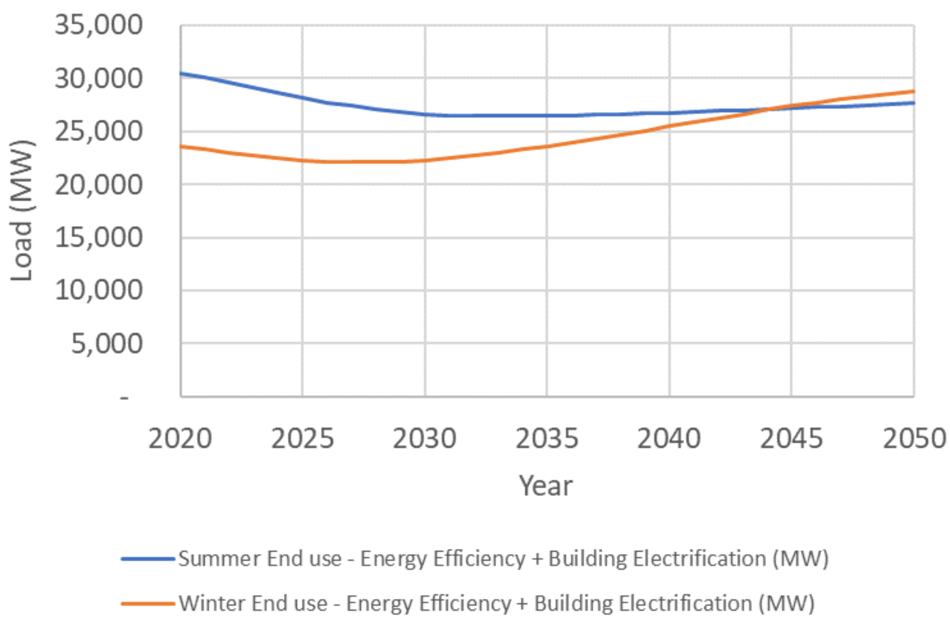


Figure 10. BTM PV and Energy Storage Capacity for the LDI Scenario

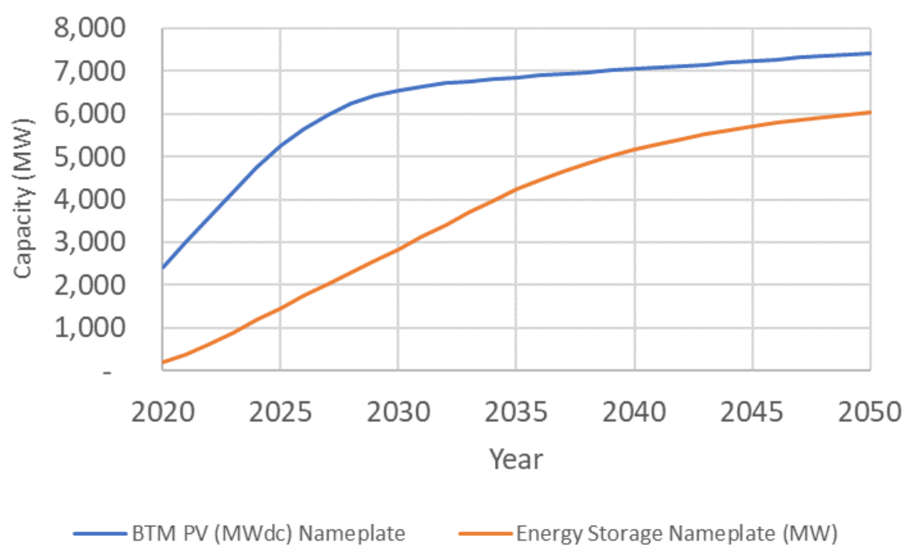


Figure 11. Unmanaged EV Charging Profile for the LDI Scenario

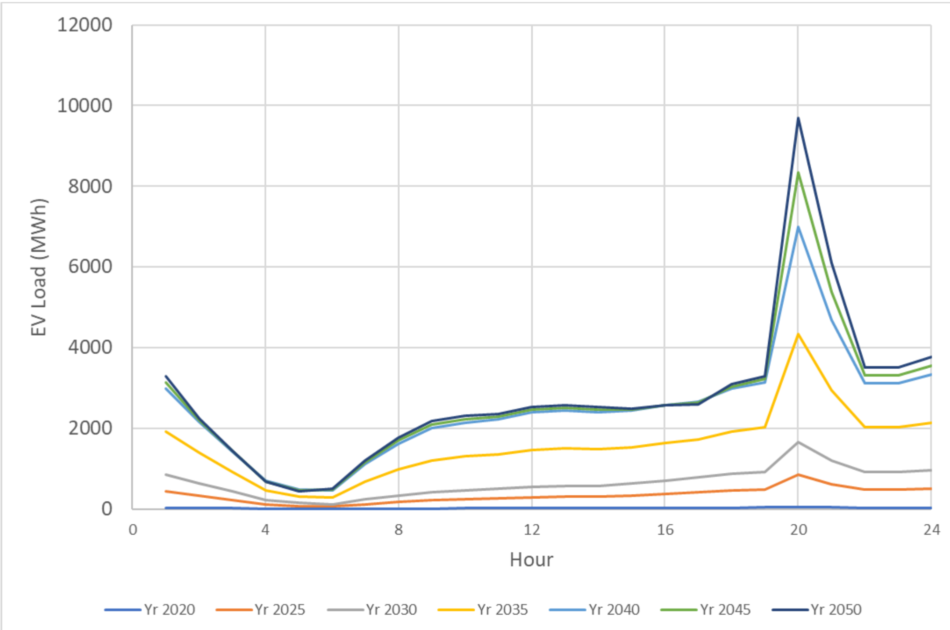
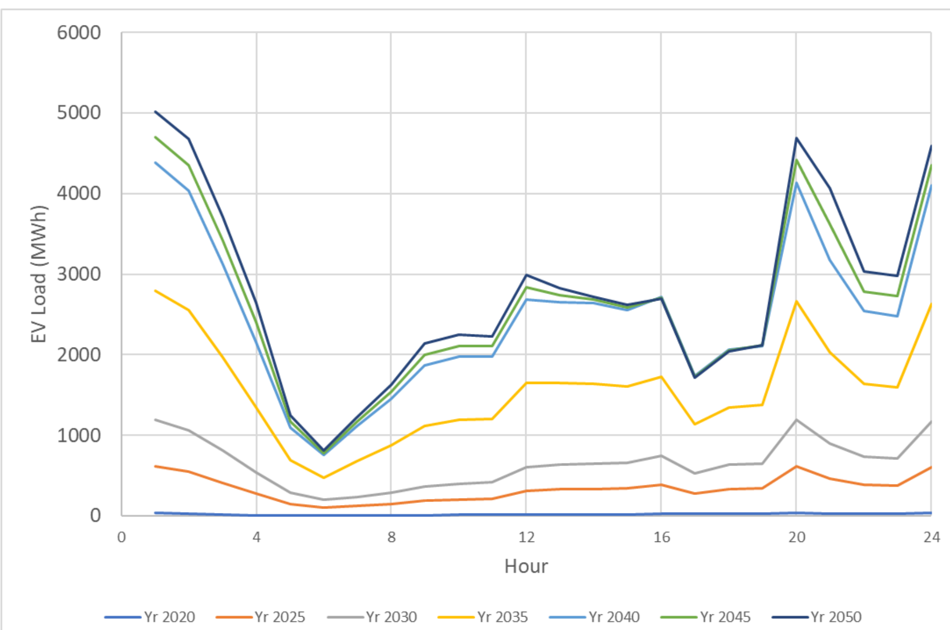


Figure 12. Managed EV Charging Profile for the LDI Scenario



4 National Grid Distribution Impact Assessment

As mentioned in section 2, National Grid's distribution system was chosen to study the impact of transportation electrification on radial distribution circuits. This section presents the methodology and the results of the analysis conducted on National Grid's distribution system.

4.1 Overview of Study Methodology

In this study, 27 representative circuits and substation configurations were studied under the scenarios described in section 3. The capacity related upgrade costs obtained from this analysis were then extrapolated for National Grid's entire service territory. Section 4.2 describes the process by which the 27 representative circuits were chosen. This section also describes how the net peak loads for each of the study years was determined for these representative circuits, banks, and the substations using the end-use load growth forecast and the growth forecasts for energy efficiency, BTM, PV, energy storage, building electrification, and transportation electrification.

The forecasted net peak load for the circuits and banks were compared with their ratings to determine if there was a projected overload. When there was a projected overload, a rule-based approach was used to determine the solution and its cost. The solutions included upgrading or adding new circuits, upgrading or adding new banks, and adding new substations. The methodology is described in detail in section 4.3. In addition to the substation, bank, and circuit-level costs, the segment-level costs for the representative circuits were also estimated. This is described in section 4.4.

Finally, the distribution upgrade costs for the 27 representative circuits were used to extrapolate the costs for National Grid's service territory based on the number of circuits that resembled these 27 circuits. The methodology used for extrapolating the costs and the results is provided in section 4.5.

4.2 Representative Circuits and Substation Configurations

National Grid's service territory in New York State is divided into three regions (East, West, and Central), based on geographic and topological differences. A map showing the approximate boundaries of the three regions is shown in Table 4. Within each of these three regions, there are three voltages used for distribution— 13.2 kilovolts (kV), 4.8 kV, and 4.16 kV—resulting in nine groups. Within each group, three different circuit types were selected based on the peak load contribution by customer class, that is, residential and commercial. The three types of circuits are: (1) R circuits—circuits where at least 80 percent of the peak load contribution is from residential customers, (2) C circuits—circuits where at least 80 percent of the peak load contribution is from commercial customers, and (3) M circuits—mixed-use feeders that do not meet the classification criteria of the other two. The above classification results in 27 representative feeders. However, only 26 representative circuits were chosen for the study since there is no "C" circuit in the "East" region as shown in Table 4.

Figure 13. Map showing National Grid's service Territories with approximate boundaries

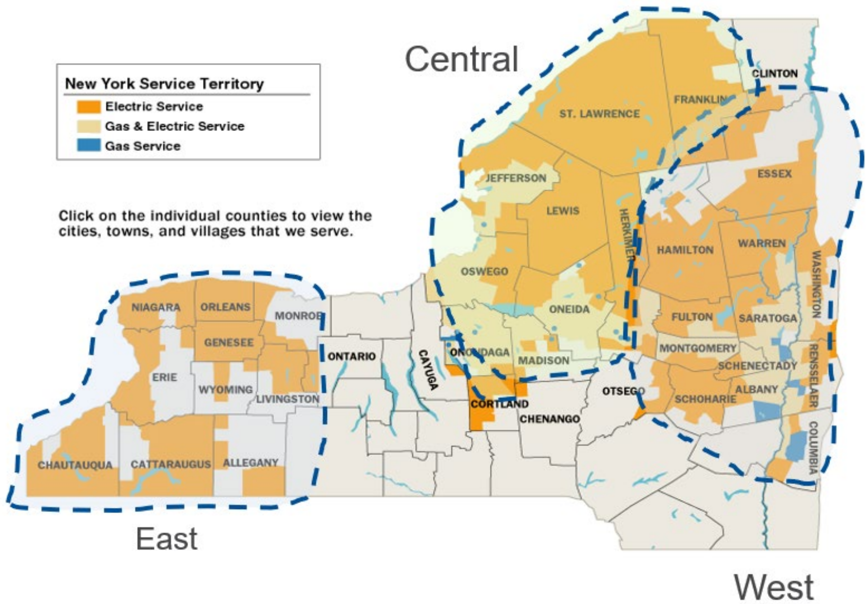


Table 4. Representative Circuits and Substation Configurations for National Grid's System

Number	Study For	Group	Number of Banks	# R	# C	# M	Config.	Group-Key
1	R	(4.16, Central)	1	1	0	3	1B, 4F	4.16, Central, R
2	C	(4.16, Central)	1	1	1	0	1B, 2F	4.16, Central, C
3	M	(4.16, Central)	1	0	0	1	1B, 1F	4.16, Central, M
4	R	(4.16, East)	2	1	0	5	2B, 6F	4.16, East, R
5	C	(4.16, East)	2	1	2	3	2B, 6F	4.16, East, C
6	M	(4.16, East)	1	0	0	3	1B, 3F	4.16, East, M
7	R	(4.16, West)	2	1	0	5	2B, 6F	4.16, West, R
8	C	(4.16, West)	2	3	1	3	2B, 7F	4.16, West, C
9	M	(4.16, West)	2	1	0	5	2B, 6F	4.16, West, M
10	R	(4.8, Central)	1	2	0	4	1B, 6F	4.8, Central, R
11	C	(4.8, Central)	1	1	1	2	1B, 4F	4.8, Central, C
12	M	(4.8, Central)	1	0	0	1	1B, 1F	4.8, Central, M
13	R	(4.8, East)	2	1	0	5	2B, 6F	4.8, East, R
14	M	(4.8, East)	1	0	0	1	1B, 1F	4.8, East, M
15	R	(4.8, West)	1	1	0	1	1B, 2F	4.8, West, R
16	C	(4.8, West)	1	0	1	2	1B, 3F	4.8, West, C
17	M	(4.8, West)	1	0	0	2	1B, 2F	4.8, West, M
18	R	(13.2, Central)	2	2	0	4	2B, 6F	13.2, Central, R
19	C	(13.2, Central)	2	0	1	6	2B, 7F	13.2, Central, C
20	M	(13.2, Central)	1	0	0	1	1B, 1F	13.2, Central, M
21	R	(13.2, East)	2	2	0	4	2B, 6F	13.2, East, R
22	C	(13.2, East)	1	0	1	3	1B, 4F	13.2, East, C
23	M	(13.2, East)	1	0	0	2	1B, 2F	13.2, East, M
24	R	(13.2, West)	2	4	0	3	2B, 7F	13.2, West, R
25	C	(13.2, West)	1	0	1	0	1B, 1F	13.2, West, C
26	M	(13.2, West)	1	0	0	3	1B, 3F	13.2, West, M

For each representative circuit, the most common substation configuration, that is, number of circuits connected to a bank and the total number of banks at the substation, were also determined using the data for all circuits and banks in National Grid's service territory. The representative circuits and their substation configurations are shown in Table 4. For example, the substation configuration for an "R" circuit in 4.16 Central is one bank with 4 feeders (1B, 4F) where there are three other "M" circuits. Note that circuit names are not included in the table due to issues of confidentiality.

4.2.1 Development of Representative Circuit Load Profiles

The net summer and winter day load profiles for each representative circuit were developed using the 2019 average net load as a starting point and adding end use, energy efficiency, PV solar, energy storage, building, and transportation electrification growth forecasts to it for each scenario. Additional details regarding the development of representative circuit load profiles are provided below for the reference and policy scenarios.

Starting point net peak load: The starting point net peak load for each representative circuit was based on the average loading of all the circuits represented by the representative circuit. For example, the starting point loading for 4.16 Central representative circuit was calculated as the average loading of all circuits that belonged to the 4.16 Central group. The summer and winter day profiles for this representative circuit (derived from historical data) was obtained from the data provided by National Grid. This profile was then scaled to match the starting point net peak load.

End-use load growth: End-use load growth for all representative circuits was based on the end-use growth for National Grid's service territory. The end-use growth for National Grid's territory was calculated as a percentage of the A-F zonal end-use forecast from the Gold Book for the reference scenario and the Pathways Study[2] for the policy scenarios. The typical summer and winter day profiles for end-use load is assumed to be the same as the load profiles for the starting point load.

Energy efficiency: Energy efficiency growth for all representative circuits is based on the energy efficiency growth for National Grid's service territory. The energy efficiency growth for National Grid's territory was calculated as a percentage of the A-F zonal energy efficiency forecast from the Gold Book for the reference scenario and the Pathways Study (see footnote 1) for the policy scenarios. The typical summer and winter day profiles for energy efficiency is assumed to be the same as the load profiles for the starting point load.

BTM PV solar: BTM PV solar growth for all representative circuits is based on the PV solar growth forecast for National Grid's service territory. Each representative circuit is assigned a portion of National Grid's PV solar growth based on its contribution to peak load. The PV solar growth for National Grid's territory was calculated as a percentage of the A-F zonal BTM PV solar forecast from the Gold Book for the reference scenario and the Pathways Study for the policy scenarios. The typical summer and winter day profiles for BTM PV solar is based on data obtained from PV Watts.

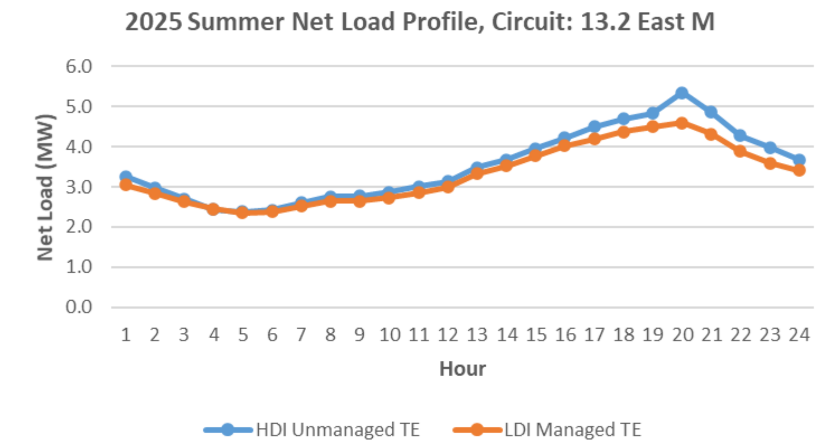
BTM energy storage: BTM energy storage growth for all representative circuits is based on the energy storage growth forecast for National Grid's service territory. Each representative circuit is assigned a portion of National Grid's energy storage growth based on its contribution to peak load. The energy storage growth for National Grid's territory was calculated as a percentage of the A-F zonal BTM energy storage forecast from the Gold Book for the reference scenario and the Pathways Study for the policy scenarios. The typical summer and winter day profiles for BTM energy storage is based on the assumption that most storage will be operated to reduce load during peak hours.

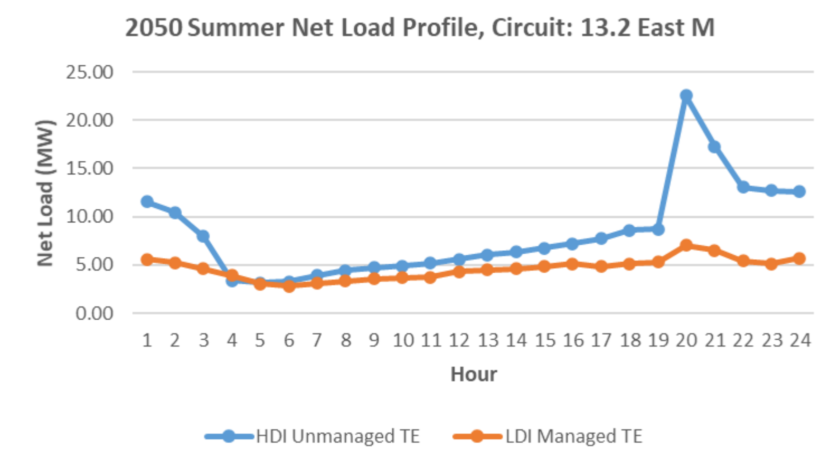
Building electrification: Building electrification (BE) growth for all representative circuits is based on the BE growth forecast for National Grid's service territory. Each representative circuit is assigned a portion of National Grid's BE growth based on its contribution to peak load. The BE growth for National Grid's territory was calculated as a percentage of the A-F zonal BE forecast from the Gold Book for the Reference Scenario and the Pathways study for the Policy Scenarios. The typical summer and winter day profiles for BE is based on an analysis of publicly available information on building electrification load profiles.

Transportation electrification: Transportation electrification load profiles for the reference and policy scenarios were developed from the ZIP code level EVSE forecast derived from the CTR study. This is discussed in section 4.2.2.

Figure 14 shows the summer and winter net peak load profile for 2025 and 2050 for one representative circuit. The net peak loads for all the representative circuits under each scenario can be found in appendix C.

Figure 14. Net Peak Load Profile for 2025 and 2050 for the Policy Scenarios for 13.2 East Circuit





4.2.2 Development of Electric Vehicle Load Profiles

As a part of the Clean Transportation Roadmap, Cadmus estimated the total energy required to support transportation electrification in New York State. This was estimated for the reference and each mitigation case and assigned to charger use cases. For the TEDI study, Cadmus derived unmanaged and managed EV load shapes using the energy estimates from the CTR.

Cadmus derived the unmanaged load shapes for each charger use case based on publicly available empirical data, vehicle duty cycles for MHDVs, and expert insight. Managed charging measures modeled in the Study primarily focus on managing EV load around NYISO system net load after integration of renewables— referred to as "system peak avoidance." Additionally, measures to address site-level peak demand, referred to as "demand management," were modeled for some MHDV charger use cases, as applicable. In its analysis, Cadmus determined that the most appropriate and promising applications for managed charging measures and resulting flexible load are from residential charging of LDVs and depot charging of MHDV fleet vehicles.[3,4,5]

Economy-wide modeling conducted by E3 as part of the Pathways Study determined system peaks and troughs for each season in benchmark years. This system-level information informed how managed charging measures were applied to each vehicle sub-sector. Notably, most vehicle operations and charging protocols do not vary significantly by season. To account for this constraint, managed charging measures were designed to minimize system peaks across the entire year.

For the LDV sub-sector, to analyze user participation and responsiveness to electricity price signals, Cadmus drew from real-world data and thus incorporated some of the unique factors that characterize charging behavior. For the analysis, Cadmus applied take-up rates of up to 92 percent, akin to take-up rates documented for single-metered charge management measures where participants are defaulted into participation. This reflects the assumption that technology readiness and regulatory acceptance of virtual submetering or internal EVSE metering will eliminate the need for the installation of a secondary EV-specific meter.

For the MHDV sub-sector, take-up of managed charging measures varies across vehicle categories and measure type. Given this understanding, Cadmus assumed less than 100 percent of the State's medium- and heavy-duty fleet take up a managed measure. In all cases, Cadmus assumed fleet managers were rational actors that would cost optimize to the extent feasible within the constraints of their operational duty cycles. Cadmus applied time-of-use (TOU) signals based on TOU periods designed around system peaks to enable system peak avoidance. Duty cycles were then shifted in response to signals from the TOU rate. Additionally, Cadmus applied site-specific demand management designed to reduce the site-specific peak. This was modeled by evenly distributing vehicle energy over the entire period the vehicle is in the yard.

Appendix B provides additional information on the ZIP-code level derivation of energy consumption from EVs.

4.3 Expansion Methodology for Circuits and Bank Addition

For this study, Resource Innovations developed an Excel-based distribution system, economic expansion model to study the overloads on circuits, banks, and substations, and estimated potential distribution upgrades. The key inputs to this tool are the summer and winter daily net load profiles for all the representative circuits for the study years 2021 to 2050. The expansion model captures typical planning criteria such as N-0 loading and loss of a bank (N-1). However, they do not duplicate the utility planning processes which are much more data intensive, more granular, and focus on a much shorter timeframe. The overall approach is one of simulating the planning processes followed by the utilities to estimate the approximate costs of distribution system upgrades due to EV load growth. Since it's a long-term economic study, it does not replicate the exact planning processes used or deal with the granularity that short-term distribution planning must consider. A high-level description of the key functionality of the tool is provided in the following sections.

4.3.1 Circuit and Bank Overload Determination

As described in section 5.2, National Grid's distribution upgrade costs are estimated by studying the upgrade investments identified by the economic expansion model for the 27 representative circuits under each circuit's most common substation configuration. For example, "R" circuit in 4.16 Central is studied using a "1 bank with 4 feeders" configuration where there are three other "M" circuits in addition to the "R" circuit.

As mentioned earlier, a key input to this tool are the summer and winter daily net load profiles for each representative circuit. The summer and winter load profiles for the bank are calculated by adding any changes (increases or decreases) in the circuit loading to the starting point bank loading. The starting point bank loading is determined statistically by averaging the loading of all the banks in that group. For example, the starting point loading of the bank in 4.16 Central is determined by averaging the loads of all the banks in this group. The loading of this bank going forward is calculated by adding any changes in loading from the 1R and the 3M circuits to this load.

The peak load on each representative circuit is determined from the summer and winter daily net load profiles discussed above. Similarly, the peak load on the bank(s) associated with each representative circuit is determined from the summer and winter daily net load profiles for banks discussed above. The model cycles through each year and determines the overloads on the representative circuits and banks by comparing their peak loads with the respective ratings. If a representative circuit or bank is overloaded, the model uses a rule-based approach to determine the upgrades or additions required. This is discussed in the following sections for circuits and banks.

4.3.2 Circuit Expansion Process

If a circuit is projected to overload, the model first determines the possibility of reconductoring the circuit (replacing the existing conductors with larger conductors while using the same poles) using a standard National Grid conductor (336 AL). The first check the model performs is to see if the rating of the circuit can be increased by reconductoring with a standard conductor. If it's possible, then the model checks to see if the reconductored circuit will again be overloaded within the next three years using the load forecast. If the reconductored circuit will not be overloaded within three years, then the model makes the decision to reconductor the circuit. If not, the model adds a new circuit with the standard conductor instead of reconductoring.

The cost of reconductoring[6] utilizes a methodology that duplicates the inherent variability of reconductoring needs. Reconductoring costs largely depend on the length of the circuit segment that requires an upgrade in the conductor. A repeatable, pseudo-random function was created to introduce some amount of uncertainty in the length of the reconductored circuit and its cost. New circuit costs are determined in a similar fashion to reconductoring costs. There were also limits placed on the number of circuits that could be added to a bank. This limit for various regions is given in Table 5.

Table 5. Maximum Number of Circuits per Bank

Voltage	Region	Maximum Feeders per Bank
4.16	West	4
4.16	Central	4
4.16	East	4
4.8	West	3
4.8	Central	3
4.8	East	3
13.2	West	4
13.2	Central	4
13.2	East	4

4.3.3 Bank and Substation Expansion Process

Bank overloads are checked simultaneously with circuit overloads in the model. National Grid's (N-1) planning criteria for loss of bank at multi-bank substations is used for determining the cumulative rating of banks at a substation. For example, if there are two banks at a substation each rated at 4.68 Mega Volt-Ampere (MVA), the cumulative rating of the two banks per National Grid's policy will be 5.62 MVA (120 percent of 4.68) and not 9.36 MVA (4.68 x 2). This is because of the N-1 rule which requires the substation to handle the full load in the event that a bank is out. In this case, the bank that is still in service should be able to take the load of the bank that is on outage and is allowed to operate at its emergency rating of 120 percent. The N-1 rule was applied to determine the cumulative bank capacity at a substation not only for existing banks, but also when new banks were added. Similar to circuits, there was a limit placed on the number of new banks that could be added to a substation. Based on the input provided by National Grid, it was assumed that it would be possible to add one more bank at the substations in all the groups, except 4.16 West where it was assumed that no additional banks could be added.

The rating and cost of the standard banks used in the model for the various distribution voltages are shown in Table 6.

Table 6. Standard Bank Ratings and Costs

Low-Side Voltage (KV)	Standard Bank Rating (MVA)	Cost ($)
4.16	6.25	2,000,000
4.8	6.25	2,000,000
13.2	12.5	2,600,000

If the banks are overloaded and the limit on the number of banks that can be added to the substation is reached, the next option is to add a new substation. The total capital cost of adding a new substation with one bank (three breakers) and one circuit with an average length of 2 miles is given in Table 7.

Table 7. Standard Substation Costs

Voltage	Bank Cost ($)	Feeder Cost ($)	Total Cost ($)
4.16	4,000,000	1,400,000	5,400,000
4.8	4,000,000	1,400,000	5,400,000
13.2	5,200,000	1,800,000	7,000,000

In addition to identifying the capital investment costs associated with circuit, bank, and substation upgrades or additions, the model also assigns annual operations and maintenance (O&M) costs for 45 years from the year the capital upgrade is made. This is based on an assumed 45-year life associated with circuits, banks, and substations. The annual O&M cost is assumed to be 5 percent of the capital cost for National Grid.

4.4 Methodology for Estimating Segment-Level Upgrade Costs

In addition to costs associated with improvements to substations, banks, and circuits, there may be other costs associated with upgrading downstream circuit segments to increase capacity, adding voltage regulation equipment, and upgrading or adding new distribution service transformers. This section describes how these costs were estimated.

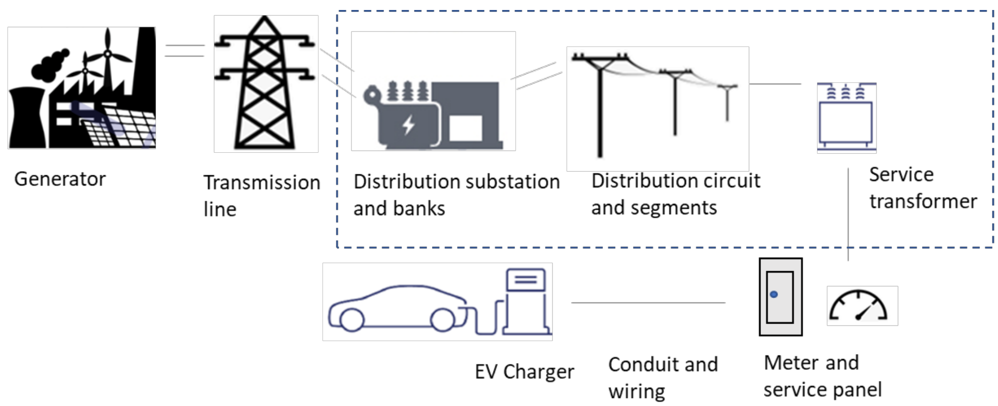
For estimating the number of distribution transformers that needed to be replaced, a simple analysis using loadflow files was used to obtain a high-level estimate of how many needed to be upgraded. Resource Innovations obtained CYME[7] loadflow files from National Grid for 10 circuits that represented system conditions in 2019. The loading of each distribution transformer was increased over the study period at the same growth rate that was observed on similar circuits. For example, if the 13.8 KV circuit loading doubled in 2050, it was assumed that the loading on each distribution transformer on that circuit would also double. This simple approach was taken since there was not sufficient reliable information to allocate the circuit-level load growth to the distribution transformers based on customer information and adoption rates.

Based on this analysis, the percentage of distribution transformers that would be overloaded (loaded above 120 percent of its normal rating) and hence need to be replaced was estimated. This value was then applied to the total population of distribution transformers to estimate how many would need to be replaced in the period between 2020 and 2050. In making these calculations, the team recognized that some of these transformers would have to be replaced anyway due to aging. Based on the final count of transformers that needed to be replaced and using a typical cost for replacement ($5,000), provided by National Grid, the distribution transformer upgrade costs were calculated. As pointed out earlier, this high-level analysis was conducted with the limited information available.

In order to estimate the costs associated with upgrading downstream circuit segments for capacity and maintaining voltage, it was assumed that every time a circuit, bank, or substation was upgraded, some costs would be incurred for making upgrades at the segment level for improving capacity and voltage. Specifically, for any upgrade of circuit, bank, or substation, an additional cost $150,000 was assumed for voltage regulation equipment and $95,000 for segment-level capacity upgrade.[8]

In addition to these segment-level costs, there may be other costs associated with electric vehicles, such as costs of providing service to the charging stations and connecting them to the distribution grid, costs of upgrades on the customer-side of the meter[9], etc. These costs are not estimated in this study. Figure 15 shows the components of the utility's and customer's distribution systems. The costs that are estimated in this study are shown in the blue dotted box.

Figure 15. Figure Showing the Components of the Utility Distribution System and Customer Connection



4.5 Extrapolation for National Grid's Service Territory

Sections 4.3 and 4.4 presented how circuit, bank, substation, and segment-level costs were calculated at the representative circuit level. In this section, the methodology used to extrapolate these costs to the National Grid service territory is discussed. Section 6.1 provides the methodology for scaling these results to the New York State level for utilities other than Con Edison.

The output of the National Grid expansion model includes the type of upgrade (reconductoring, feeder, bank, or substation), the capital cost for the upgrade, and the O&M cost associated with the upgrade for all 26 representative circuits. Segment costs associated with upgrading downstream circuit segments and adding voltage regulation equipment were added to the capital costs developed by the model. This resulted in total capital and O&M costs for substations, circuits, and segments for all 26 representative circuits. Before these costs could be scaled up, they were unitized, that is, they were revised to represent a cost per unit for circuits or substation banks.

To extrapolate the unitized upgrade-related costs for the 26 representative circuits to the National Grid level, 26 circuit groups and nine bank groups were defined. The circuit groups were formulated based on the three voltage levels (4.16 kV, 4.8 kV, and 13.2 kV), three regions (east, west, and central) and three customer types (residential, commercial, and mixed). The bank groups were formulated based on the three voltage levels and the three regions.

The scaling process for circuits is slightly different to the bank scaling process as described in the following.

Scaling Up of Circuit Costs: Unitized capital costs and O&M costs were scaled up using the number of circuits in the respective grouping as a multiplier. There were 26 groups used in this scaling process.

Scaling Up of Bank Costs: A weighted average cost has been developed based on number of residential, commercial, and mixed circuits in the bank group. Finally, the bank costs were scaled up using the weighted cost and the number of banks in the group as a multiplier.

The scaled-up circuit costs, bank costs, and distribution transformer upgrade costs discussed in section 4.4 were aggregated together to obtain a total annual capital and O&M cost for National Grid's service territory for each year of the study.

These annual capital and O&M costs were then averaged for each five-year period, 2021–2025, 2026–2030, etc. to more easily present the study results. These five-year average annual capital and O&M costs are in 2020 dollars. The net present value (NPV) of these costs is also calculated for each scenario using a discount rate of 3.6 percent. The NPV can be used for comparing the distribution cost impact of the different scenarios.

5 Con Edison Distribution Impact Assessment

5.1 Overview of Study Methodology

Con Edison serves customers in the five boroughs of New York City and Westchester County. The distribution systems in Manhattan, Bronx, Brooklyn, and Queens are secondary networked distribution systems and the ones in Staten Island and Westchester are radial distribution systems. Con Edison's 82 secondary networks deliver power to specific geographies within its service territory. Each network is supplied by high-voltage "feeders" coming from local substations. Transformers connected to these feeders are dispersed throughout the networks to support the low-voltage grid from which many of their customers draw their power.

Most, if not all, of Con Edison's network distribution systems have a "N-2" (also known as second contingency) design criteria. Under this criteria customers' peak electric demand should still be able to be met without overloading network components beyond design limits when any two network feeders are out of service.

Due to the complexities associated with planning for a secondary networked system with N-2 contingencies and in an effort to improve accuracy, the team decided that the TEDI study team employ the same tool used by Con Edison for its distribution planning rather than simulate the expansion as in the case of National Grid. Con Edison uses PVL (Poly Voltage Loadflow) as its principal distribution system design and analysis tool. PVL is capable of identifying overload of transformers, primary feeder sections, secondary mains, low voltage of primary and secondary buses, and provides detailed reports showing the loading and voltages of each component in the system. Due to the proprietary nature of the PVL software and the steep learning curve associated with learning how to use it, the PVL simulations were performed by Con Edison's regional planners.

For the Con Edison study, five representative networks were studied under the scenarios described in section 3. The upgrade costs obtained from this analysis were then extrapolated to all of Con Edison's service territory. Section 5.2 describes the process by which the five representative networks were chosen. This section also describes how the net peak loads for each of the study years was determined for the five networks using the end-use load growth forecast and the growth forecasts for energy efficiency, BTM PV, energy storage, building electrification, and transportation electrification.

The forecasted net peak loads were fed into PVL by regional planners to identify overloads and then engineers applied design standards to determine the solutions and their cost. The solutions included upgrading equipment on both the primary and secondary portions of the distribution network. The results of the expansion modeling for the five representative networks are presented in section 5.3. Since the network upgrade costs do not include any costs associated with area substation upgrades or additions, a separate process was used to estimate these costs. This is discussed in section 5.4. Finally, section 5.5 provides information on the approach used for extrapolating the results for the representative networks to Con Edison's service territory.

5.2 Representative Networks

Con Edison serves customers in the five boroughs of New York City and Westchester County. The distribution systems in Manhattan, Bronx, Brooklyn, and Queens are secondary networked distribution systems and the ones in Staten Island and Westchester are radial distribution systems. For this analysis, four representative networks from Manhattan, Bronx, Brooklyn, and Queens were initially chosen. They were as follows: Grand Central, Central Bronx, Sheepshead Bay, and Wainwright. The representative networks were chosen such that their loading generally represented the group of networks or their borough location. Later in the study, another network (Yorkville) was added to represent residential networks in Manhattan. The PVL simulations were performed on these five representative networks and extrapolated to the group of networks that they represented.

5.2.1 Development of Network Load Profiles

The net summer and winter day load profiles for each representative network was developed using the 2021 (forecasted) net peak load as a starting point and adding the following to each scenario: end use, energy efficiency, PV solar, energy storage, and building and transportation electrification growth forecast. Additional details regarding the development of representative network load profiles are provided below for the reference and policy scenarios.

Starting point net peak load: The starting point net peak load for each representative network was based on the 2021 (forecasted) net peak load obtained from Con Edison. The typical summer and winter day profiles for each representative circuit was also obtained from the data provided by Con Edison. This typical profile was then scaled to match the starting point net peak load.

End use load growth: End-use load growth for all representative networks is based on the end-use growth for the group or borough the network represents. The end-use growth for the group was calculated using the load growth for Con Edison's service territory and the load in each group (load-weighted growth rate). The end-use growth for Con Edison's territory was calculated as a percentage of the NYISO H-J zonal end-use forecast from the Gold Book for the reference scenario and the Pathways Study[10] for the policy scenarios. The typical summer and winter day profiles for end-use load is assumed to be the same as the load profiles for the starting point load.

Energy efficiency: Energy efficiency growth for all representative networks is based on the energy efficiency growth for Con Edison's service territory. The energy efficiency growth for Con Edison's territory was calculated as a percentage of the H-J zonal energy efficiency forecast from the Gold Book for the reference scenario and the Pathways Study (see footnote 7) for the policy scenarios. The typical summer and winter day profiles for energy efficiency is assumed to be the same as the load profiles for the starting point load.

BTM PV solar: BTM PV solar growth for all representative networks is based on the PV solar growth forecast for Con Edison's service territory. Each representative network is assigned a portion of Con Edison's PV solar growth based on its contribution to peak load. The PV solar growth for Con Edison's territory was calculated as a percentage of the H-J zonal BTM PV solar forecast from the Gold Book for the reference scenario and the Pathways Study for the policy scenarios. The typical summer and winter day profiles for BTM PV solar is based on data obtained from PV Watts.

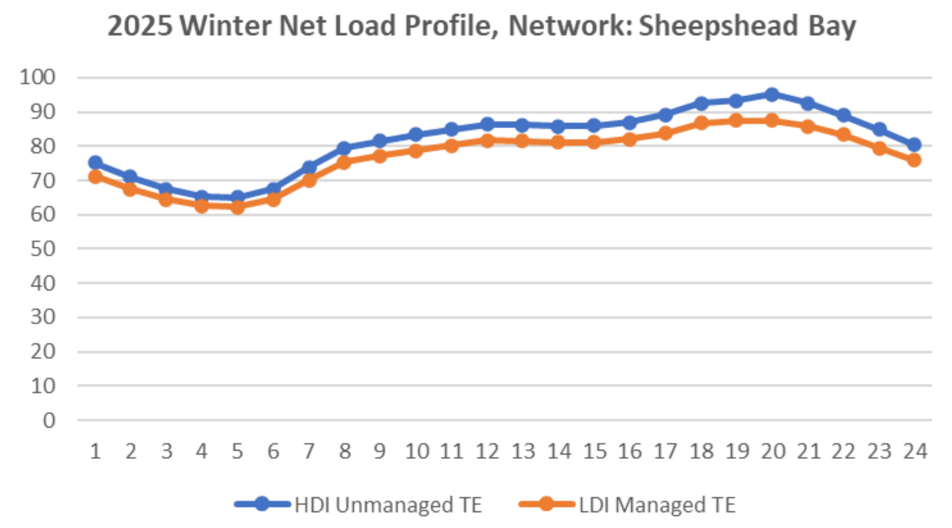
BTM energy storage: BTM energy storage growth for all representative networks is based on the energy storage growth forecast for Con Edison's service territory. Each representative network is assigned a portion of Con Edison's energy storage growth based on its contribution to peak load. The energy storage growth for Con Edison's territory was calculated as a percentage of the H-J zonal BTM energy storage forecast from the Gold Book for the reference scenario and the Pathways Study for the policy scenarios. The typical summer and winter day profiles for BTM energy storage are based on the assumption that most storage will be operated to reduce load during peak hours.

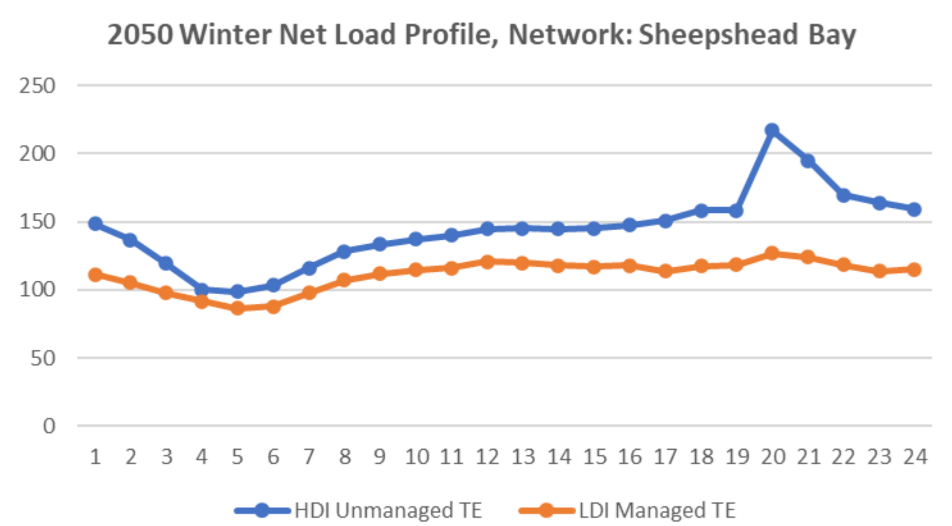
Building electrification: Building electrification growth for all representative networks is based on the BE growth forecast for Con Edison's service territory. Each representative network is assigned a portion of Con Edison's BE growth based on its contribution to peak load. The BE growth for Con Edison's territory was calculated as a percentage of the H-J zonal BE forecast from the Gold Book for the reference scenario and the Pathways Study for the policy scenarios. The typical summer and winter day profiles for BE is based on an analysis of publicly available information on building electrification load profiles.

Transportation electrification: Electrification load profiles for the reference and policy scenarios were developed from the ZIP code-level EVSE forecast derived from the CTR study. This is discussed in section 6.2.2.

Figure 16 shows the winter peak load profiles with and without managed charging for the years 2025 and 2050 for one representative network. The net peak loads for all the representative circuits under each scenario can be found in appendix D.

Figure 16. Winter Net Load Profile for Sheepshead Bay for the Years 2025 and 2050





5.2.2 Development of Electric Vehicle Load Profiles

Cadmus estimated the total energy required to support transportation electrification in New York State. This was estimated for the reference and for each mitigation case and assigned to charger use cases. Cadmus derived unmanaged load shapes for each charger use case based on publicly available empirical data, vehicle duty cycles for MHDVs, and expert insight. The process used by Cadmus for developing electric vehicle load profiles is described in section 4.2.2. The process used for developing the load profiles for Con Edison is the same as the process used for National Grid.

5.3 Approach for Estimating Distribution Costs for Representative Networks

The distribution capital costs for the five representative networks used in the study were developed by Con Edison. These costs were developed using the PVL analysis mentioned in section 5.1. The inputs to the PVL analysis were the net load forecasts for the five representative networks developed by Resource Innovations. The capital costs developed included costs for installation of new equipment and the capital cost associated with the replacement of equipment as part of the capital project. The cost of replacement of equipment[11] was estimated by scaling up the capital costs by 23.6 percent, a factor provided by Con Edison for this purpose.

O&M costs over the 45-year life of the new assets were calculated using the following two factors:

- One time O&M cost: 6.5 percent of the capital costs
- Ongoing annual O&M: 1.1 percent of the capital costs

Since the cost estimating process using PVL is very labor intensive, the approach used to estimate the capital and O&M costs was to study the highest net load among all the study cases for the five representative networks and then to use a form of interpolation to estimate the costs for cases with lower net load. For example, Grand Central, one of the five representative networks, had the highest net load of 197 megawatts (MW). Using the PVL analysis, Con Edison developed the costs associated with this load. For the reference case with Managed TE study scenario, the highest net load was 189 MW. This net load was reached in 2035 in the PVL analysis. The interpolation methodology first determined the upgrade costs that were incurred between 2020 and 2035, and then these costs were distributed over the full-study period of 30 years. This interpolation methodology was used for all study scenarios and for all representative networks.

5.4 Approach for Estimating Area Substation Upgrade Costs

Area substation upgrade costs were estimated using a system level approach rather than a representative network approach. This is because the area substations are connected together and function more like a network and less like a radial system. Thus, projected overloads of an area substation can be addressed by shifting load from one substation to another, thus minimizing capital investments. Summer and winter peak loads along with the area station upgrade costs in Con Edison's service territory were provided by Con Edison for the year 2050.

First, area upgrade costs for year 2050 were developed using the total system load and the area station upgrade costs for the study case of interest for both summer and winter. These costs represent the costs for all of the upgrades that would need to be made over the 2020 to 2050 time period. An interpolation method was used to determine how these costs were likely to be spent on an annual basis during this 30-year period. The methodology assumed that costs would grow slightly more in the last 15 years than in the first 15 years and also considered whether the Con Ed system peaks in summer or winter in each of the 30 years.

Finally, associated O&M costs over the 45-year life of the new asset were calculated using the following two factors provided by Con Ed:

- One time O&M cost: 2.7 percent of the capital costs
- Ongoing annual O&M: 1 percent of the capital costs

5.5 Extrapolation for Con Edison's Service Territory

Section 6.3 discussed how the representative network costs were calculated. In this section, the discussion relates to the methodology used to scale up these costs to Con Edison's service territory.

As mentioned in section 5.2, the representative networks represent various regions and group of networks in Con Edison's service territory. In order to scale up the representative network costs to their entire service territory, a scaling factor for a group was developed using the 2021 peak loads. The following formula was used to develop the scaling factor:

Scaling factor = Total peak load for the representative network group/peak load for the representative network.

Table 8 shows the total peak load and the scaling factors that were developed.

Table 8. Scaling Factors for Representative Networks

Representative Network	Number of Networks in the Group	Representative Network Peak (MW)	Sum of Peak for Group (MW)	Scaling Factor
Grand Central	26	161	2666	16.56
Central Bronx	6	193	745	3.86
Sheepshead Bay	16	162	3490	21.54
Wainright	19	85	2651	31.19
Yorkville	15	289	2796	9.67

The representative network costs were multiplied by the respective scaling factors and aggregated together to obtain the total Con Edison level capital and O&M costs for network upgrades. Finally, Con Edison's system level area station costs (discussed in section 5.4) were added to the network upgrade costs to obtain the total capital and O&M costs for Con Edison's service territory.

6 New York State Distribution Upgrade Costs

6.1 Overview of Extrapolation Approach

The distribution upgrade costs for the remaining utilities (excluding Con Edison and National Grid) were calculated using National Grid's per unit circuit and bank costs because their distribution networks are similar to National Grid's. The data provided by the remaining utilities consisted of peak loads for the circuits and the type (residential versus commercial) of the circuits in their service region. This information was categorized into six groups (residential high voltage, residential low voltage, commercial high voltage, commercial low voltage, mixed high voltage, and mixed low voltage) and the count of circuits within each group was developed. Similarly, National Grid's unitized circuit and bank costs were categorized into the same six groups based on the voltage level and the customer type of the representative circuits. The cost of distribution upgrades for the remaining utilities was calculated by taking the product of per unit cost and the count of circuits within the respective groups.

The total State-level capital and O&M cost was obtained by adding the capital cost and O&M cost for National Grid, Con Edison, and the remaining utilities.

6.2 Data Received from Other Utilities

In order to estimate distribution upgrade costs for the other utilities, PSEGLI, O&R, CHGE, NYSEG, and RGE provided the following data:

- Number and list of voltage level utilized.
- Number of residential circuits (circuits with 80 percent or more of the peak attributed to residential customers).
- Number of commercial circuits (circuits with 80 percent or more of the peak attributed to commercial customers).
- Average peak demand for the residential customers.
- Average peak demand for the commercial customers.
- Total non-coincident peak load on the distribution system for 2019.

This information was processed as per section 6.1 to develop the distribution upgrade cost for the above-mentioned utilities (remaining utilities). The next section discusses the distribution upgrade costs for New York State as a whole based on the costs estimated for National Grid, Con Edison, and the remaining utilities.

6.3 New York State Distribution Upgrade Costs

As mentioned earlier, the statewide annual capital and O&M costs associated with distribution system upgrades are averaged for each five-year period, 2021–2025, 2026–2030, etc. to more easily present the study results. These five-year average annual capital and O&M costs are expressed in 2020 dollars. A discount rate of 3.6 percent was used to calculate the NPV of the annual costs for the year 2021. The NPV can be used for comparing the distribution cost impact of the difference scenarios.

Figure 17 shows the NPV of the capital costs for the reference and policy cases with and without managed EV charging. It can be observed that the NPV ranges from $2.18 in the LDI Managed EV charging case to $27.2 billion in the HDI unmanaged case. These costs can be thought of as bookends to the distribution upgrade costs. The ratio of the upper to lower bookend distribution costs is 12.5. This ratio tightens to 7.5 times if compare to the distribution system upgrade costs for the HDI and LDI managed EV charging cases.

It can be observed from the results that the distribution upgrade costs are significantly lower with managed EV charging—61 percent and 46 percent of the unmanaged case for HDI and LDI scenarios respectively showing that managed charging would play a significant factor in lowering the distribution upgrade costs. Table 9 shows the NPV of the capital upgrade costs for each five-year period for the nine study cases. Table 10 shows the capital upgrade costs for each five-year period in 2020 dollars.

The NPV of the distribution upgrade costs due to transportation electrification alone can be calculated by subtracting the costs of the "No-TE" case from the case with TE. This value ranges from $1.4 billion in the LDI Managed EV charging case to $26.8 billion to the HDI Unmanaged case as shown in Table 11.

Figure 18 shows the distribution upgrade costs (in 2020 $) associated with the "No-TE," managed and unmanaged EV charging for the HDI scenario. It can be observed that as the peak load grows due to transportation electrification, the distribution upgrade costs increase almost linearly.

Figure 17. Plot Showing NPV of Capital Costs Associated with Distribution Upgrade Projects

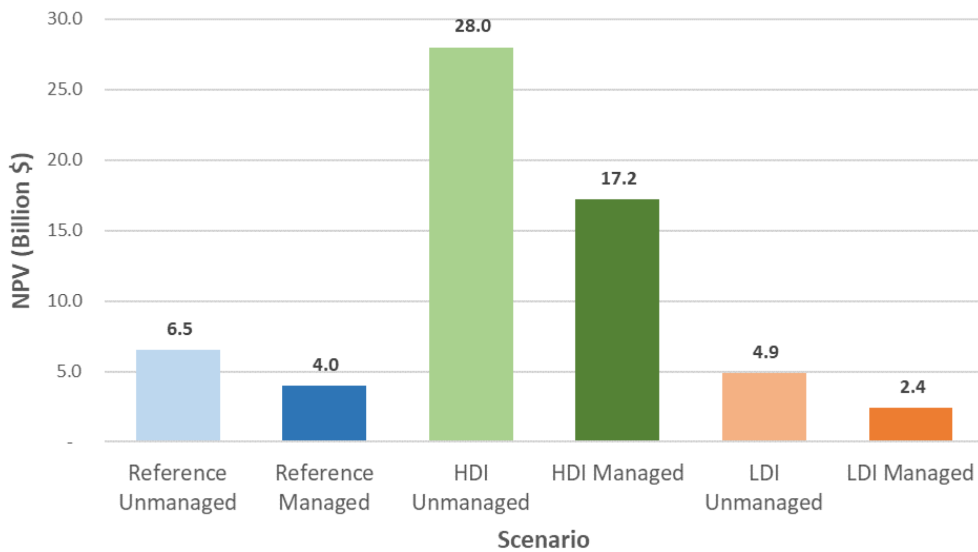


Figure 18. System Peak Load and NPV of Distribution Upgrade Costs for the HDI Scenario

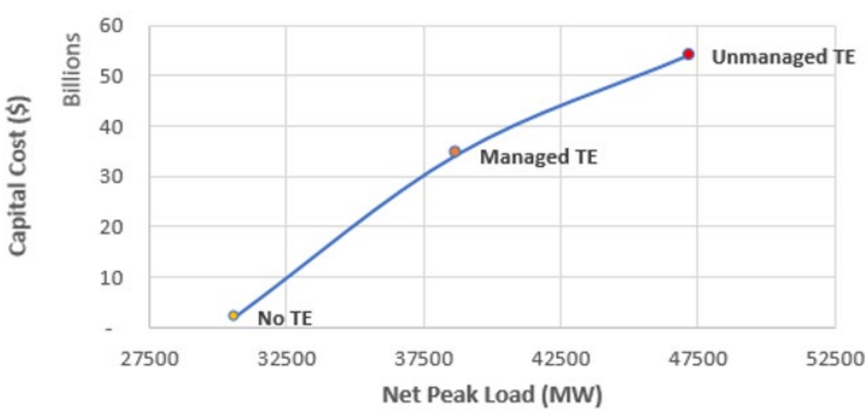


Table 12 shows the NPV of the operations and maintenance costs for each five-year period from 2021 to 2095. As mentioned earlier, it was assumed that operations and maintenance (O&M) costs would be incurred for 45 years from the year the capital upgrade is made.

Table 9. Statewide Five-Year NPV Capital Costs

	Reference Scenario			High-Distribution System Impact Scenario			Low-Distribution System Impact Scenario		
	Unmanaged TE	Managed TE	No TE	Unmanaged TE	Managed TE	No TE	Unmanaged TE	Managed TE	No TE
2021-2025	907,614,435	442,673,900	263,081,243	938,363,848	625,534,598	136,028,804	298,979,240	152,449,250	116,453,613
2026-2030	678,520,429	482,997,485	281,018,056	1,589,387,857	774,711,042	178,945,396	316,151,575	185,281,774	148,269,851
2031-2035	1,386,155,689	752,284,057	286,229,036	9,687,804,099	5,414,242,405	205,632,611	1,012,863,769	314,862,069	166,713,048
2036-2040	1,026,525,439	580,602,287	282,368,239	6,508,733,706	4,661,854,493	216,862,434	961,513,009	567,999,877	175,282,442
2041-2045	935,949,152	713,806,458	292,694,948	4,253,716,930	1,244,067,169	219,931,847	1,118,162,324	852,190,341	176,694,258
2046-2050	1,594,364,928	1,055,945,542	275,524,890	4,987,815,621	4,495,001,947	218,616,378	1,234,846,548	281,701,490	173,043,610
Total	6,529,130,072	4,028,309,730	1,680,916,412	27,965,822,060	17,215,411,654	1,176,017,469	4,942,516,465	2,354,484,801	956,456,821

Table 10. Statewide Five-Year Capital Costs in 2020 Dollars

	Reference Scenario			High-Distribution System Impact Scenario			Low-Distribution System Impact Scenario		
	Unmanaged TE	Managed TE	No TE		Unmanaged TE	Managed TE	No TE		Unmanaged TE
2021-2025	983,577,467	491,609,310	292,163,574	2021-2025	983,577,467	491,609,310	292,163,574	2021-2025	983,577,467
2026-2030	899,286,114	640,147,169	372,451,035	2026-2030	899,286,114	640,147,169	372,451,035	2026-2030	899,286,114
2031-2035	2,199,325,918	1,217,930,565	452,738,496	2031-2035	2,199,325,918	1,217,930,565	452,738,496	2031-2035	2,199,325,918
2036-2040	1,955,772,517	1,092,944,675	533,025,957	2036-2040	1,955,772,517	1,092,944,675	533,025,957	2036-2040	1,955,772,517
2041-2045	2,090,391,237	1,592,255,633	659,396,317	2041-2045	2,090,391,237	1,592,255,633	659,396,317	2041-2045	2,090,391,237
2046-2050	4,286,276,419	2,852,362,676	740,782,827	2046-2050	4,286,276,419	2,852,362,676	740,782,827	2046-2050	4,286,276,419
Total	12,414,629,672	7,887,250,029	3,050,558,207	Total	12,414,629,672	7,887,250,029	3,050,558,207	Total	12,414,629,672

Table 11. NPV of Distribution Upgrade Costs due to Transportation Electrification

	Reference Scenario		High-Distribution System Impact Scenario		Low-Distribution System Impact Scenario	
	Unmanaged TE	Managed TE	Unmanaged TE	Managed TE	Unmanaged TE	Managed TE
Total	4,848,213,660	2,347,393,317	26,789,804,591	16,039,394,185	3,986,059,643	1,398,027,980

Table 12. Statewide Five-Year NPV O&M Costs

	Reference Scenario			High-Distribution System Impact Scenario			Low-Distribution System Impact Scenario		
	Unmanaged TE	Managed TE	No TE	Unmanaged TE	Managed TE	No TE	Unmanaged TE	Managed TE	No TE
2021-2025	45,362,711	18,011,425	11,897,710	33,551,031	24,171,002	7,752,695	13,069,464	8,055,433	6,637,045
2026-2030	70,409,547	38,845,697	24,967,480	87,530,203	56,890,935	15,897,687	27,889,187	16,523,351	13,329,275
2031-2035	119,600,097	60,607,590	36,025,880	478,468,573	219,409,580	23,960,912	61,812,129	25,648,514	19,801,515
2036-2040	162,025,622	92,424,256	44,970,214	927,300,519	552,888,638	31,263,330	108,093,138	49,397,358	25,605,043
2041-2045	194,389,278	114,585,642	52,509,715	1,137,059,632	632,781,618	37,459,949	156,060,547	97,413,862	30,498,172
2046-2050	240,523,131	145,501,246	58,320,445	1,236,041,876	746,374,849	42,427,748	189,057,401	95,223,617	34,381,875
2051-2055	231,985,788	141,699,296	48,978,884	1,142,387,074	728,395,416	34,283,466	191,425,462	80,894,658	27,795,208
2056-2060	194,384,934	118,732,309	41,040,260	957,226,038	610,335,212	28,726,714	160,398,731	67,783,043	23,290,089
2061-2065	162,878,524	99,487,871	34,388,349	802,076,379	511,410,511	24,070,614	134,400,892	56,796,593	19,515,171
2066-2070	128,143,575	80,548,484	27,170,893	666,365,856	424,553,320	19,357,841	110,737,982	46,666,324	15,657,512
2071-2075	101,206,542	63,050,896	20,054,769	546,897,423	348,784,037	14,672,376	89,710,606	37,437,021	11,823,928
2076-2080	72,823,220	47,448,955	14,014,877	376,298,043	257,705,161	10,434,798	67,652,600	29,237,737	8,389,293
2081-2085	48,736,018	31,556,730	8,973,045	208,573,463	141,146,484	6,723,100	45,483,701	19,044,573	5,395,082
2086-2090	29,152,622	19,111,395	4,700,385	101,828,085	84,051,071	3,555,467	24,995,101	4,741,565	2,847,486
2091-2095	8,830,459	6,131,737	1,190,851	27,956,928	26,663,261	912,015	9,257,241	1,364,089	729,597
Total	1,810,452,069	1,077,743,529	429,203,757	8,729,561,123	5,365,561,096	301,498,713	1,390,044,183	636,227,739	245,696,291

6.4 Use of Distribution Upgrade Costs in the Clean Transportation Roadmap

The distribution system upgrade costs estimated above were used in the companion study—The Clean Transportation Roadmap—to contextualize how shifting on-road transportation to electric vehicles could impact the grid and result in additional distribution costs. Based on the formula in Table 13, Cadmus estimated the incremental revenue requirement required by utilities in five-year increments from 2020 to 2050. For each study period, Resource Innovations estimated and supplied Cadmus with the annual incremental operating and maintenance (O&M) and capital expenditure (CapEx) costs based on forecasted load increases and infrastructure upgrades (e.g., charger counts and costs). Incremental taxes were computed according to the cumulative incremental allowed return (r*IRB) using an averaged 6.5 percent tax rate. The TEDI study assumed a 45-year asset life for all CapEx resulting in a depreciation rate of roughly 2 percent per year. Incremental depreciation represented the depreciated sum of installed capital after the base year cumulative to the study end year. The study calculated the incremental rate base by summing Resource Innovations' capital expenditure estimates and any prior depreciated incremental investments. Finally, the rate of return (r) comprised a statewide weighted average cost of capital (WACC), based on the WACC values reported by State utilities in their benefit cost analysis handbooks between 2019 and 2021 and included Central Hudson, CECONY, ORU, National Grid, NYSEG, and RG&E. The resulting average WACC, 6.76 percent, was used as the rate of return in all cases.

Table 13. Incremental Revenue Requirement Calculation

$$\mathbf{IRR = \overbrace{IO + IT + Id}^{\text{Expenses}} + r^{*}(IRB)}$$

IRR = Incremental Revenue Requirement

IO = Incremental Operating Expenses

IT = Incremental Taxes

Id = Incremental Annual Depreciation Expense

IRB = Incremental Rate Base

r = Overall Rate of Return (WACC)

The utility incremental revenue requirements were divided by various system loads to allocate the costs to the associated load categories on a dollar per kilowatt-hour basis. For transportation-related load, Table 14 displays the estimated incremental dollars per kWh under each scenario necessary to recover distribution system costs from forecasted system loads with and without transportation electrification loads. These rate impacts with additional TE loads translate to 2050 rates that are between 0.5 percent and 6percent above today's rates, whereas without any transportation electrification, rates increase by less than 0.5 percent in the reference and mitigation cases.

Cadmus incorporated these incremental rate increases into its vehicle diffusion model to estimate the impact of these higher rates on EV adoption. Cadmus found that these increased rates had minimal effect on consumers choice to purchase EVs. Even under the worst case (High-Distribution System Impact Scenario's unmanaged TE load rate impact), the rate increases resulted in 0.0012 percent fewer EV sales in a given year.

Table 14. Incremental Revenue Requirement ($/kWh) due to Distribution System Upgrades

Parent Scenario	Transportation Scenario	2021-	2026-	2031-	2036-	2041-	2046-
Reference Scenario	Unmanaged TE	$0.00	$0.001	$0.001	$0.001	$0.002	$0.003
Reference Scenario	Managed TE	$0.00	$0.00	$0.001	$0.001	$0.001	$0.002
Reference Scenario	No TE	$0.00	$0.00	$0.00	$0.00	$0.001	$0.001
High-Distribution Impact Scenario	Unmanaged TE	$0.00	$0.001	$0.005	$0.007	$0.008	$0.009
High-Distribution Impact Scenario	Managed TE	$0.00	$0.001	$0.003	$0.004	$0.004	$0.005
High-Distribution Impact Scenario	No TE	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Low-Distribution Impact Scenario	Unmanaged TE	$0.00	$0.00	$0.001	$0.001	$0.001	$0.002
Low-Distribution Impact Scenario	Managed TE	$0.00	$0.00	$0.00	$0.00	$0.001	$0.001
Low-Distribution Impact Scenario	No TE	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

7 Observations and Conclusions

7.1 Approach

The team offers the following observations and conclusions regarding the approach taken to perform the Transportation Electrification Distribution Impact (TEDI) study:

- Simulating the distribution systems planning process of utilities that have radial systems is a feasible way to estimate the costs associated with the various transportation electrification future scenarios. Such simulations can capture typical radial type planning criteria such as N-0 loading and loss of a bank (N-1). Such simulations do not duplicate the utility planning processes which is much more data intensive, more granular, and focuses on a much shorter term.
- This study focused on using the existing utility planning criteria and planning process to estimate potential costs over a 30-year time frame. It did not attempt to use the 30-year forecasts to determine if a different approach could be taken to better prepare the grid for transportation electrification expansion and to potentially optimize grid investments resulting in reduced customer costs/rates. Such a study was beyond the scope of the project but is recommended for future consideration as a way to work with utilities to prepare for rapidly changing electrification futures at the lowest cost.
- For systems that have secondary distribution networks like Con Edison, developing an economic model that captures the complexity of their planning process which uses multiple outage contingency planning criteria is much more difficult, time consuming, and expensive than for radial systems. Con Edison agreed to have their planning engineers work with Resource Innovations to simulate their planning process over a 30-year planning horizon using growth data developed by Resource Innovations. This approach allowed for analyzing the grid down to the customer transformer level, and it also allowed for costs to be developed based upon the specifics of the region and circuits where upgrades were needed.
- A simple analysis using CYME loadflow files was used to obtain a high-level estimate of how many distribution transformers need to be upgraded over the 30-year study period. This approach was taken for National Grid and the other utilities similar to National Grid, since there was not sufficient reliable information to allocate the circuit-level load growth to the distribution transformers based on customer information and adoption rates. Given the relatively small size of the impact of transformer replacement costs on the total costs, this method is believed to be adequate. However, if a study is focused to isolate these costs with precision, it is recommended that a more thorough study be considered on the costs associated with distribution transformer upgrades due to electrification.

7.2 Results

The team offers the following observations and conclusion regarding the results of the Transportation Electrification Distribution Impact (TEDI) study:

- The TEDI Study estimates the cost of upgrading the distribution systems in New York State to meet the needs of increased loading. Such upgrades, often referred to as capacity upgrades, are the result of a need for more distribution capacity to support increased power flow and voltage control equipment and the incremental operations and maintenance associated with those upgrades. The team observed that these estimates do not cover many other costs to operate the distribution systems. Examples of other costs not included in the study include costs associated with (1) replacement of equipment as part of an asset management program that considers equipment age and condition, (2) investment programs targeted to improve reliability or resiliency, (3) grid modernization, (4) operations and maintenance costs of the existing grid, etc. Thus, the team observed that these costs are not comparable to the costs that must be considered when developing rates.
- The NPV of New York State's distribution system upgrade costs due to transportation electrification varies considerably depending on the scenarios. These costs range from $2.4 billion in the LDI Managed EV charging case to approximately $28 billion in the HDI Unmanaged case. The team also observe that the distribution upgrade costs are significantly lower with managed EV charging—61 percent and 46 percent of the unmanaged case for HDI and LDI scenarios, respectively, showing that managed charging could play a signification factor in lowering the distribution upgrade costs.
- The team noted that the policy scenarios developed for this study achieve the Climate Act goals. However, the reference scenario is a business-as-usual scenario and does not meet those Climate Act goals. It is important to keep this in mind when comparing the results of the reference scenario with the results of the policy scenarios.
- The cost estimate results are, to a large extent, a result of the definition of the scenarios that were studied, and the assumptions included in each of those scenarios. The results would be different if the assumptions were different. The assumptions are based upon best available data and judgment at the time they were made. The team observed that they are likely to improve over time as more insight is gained into which scenarios are more or less likely to be the pathways that are followed to reach the Climate Act goals.
- The team observed that Con Edison developed their own set of EV projections for some of their networks which are different than what was used in this study. These projections were not available during the TEDI study and the writing of this report. Such differences could result in higher EV penetration in some networks and lower in others and these differences could shift peaks from summer to winter (see discussion below). As assumptions are improved over time, the team recommends updating the study to take advantage of more detailed insights gained through the utilities' TE and BE studies.
- By design the team observed that the TEDI study focused on developing a set of cost estimates that bracket the likely future costs. As more insight is gained into the likely pathways, the team recommends that additional study focus also on the "most likely" scenarios to provide policy makers additional insight.

- Only one of Con Edison's representative networks (Grand Central) had net load forecasts that indicated a switch from a summer peaking area to a winter peaking area. With a different assumption of load growth (i.e., more building electrification) Con Edison forecasts could have indicated a more widespread shift from summer to winter peaking.
- The analysis regarding the impact of distribution upgrade costs on adoption of EVs as described in section 6.4 used the incremental costs developed in the TEDI study to develop an approximate rate impact for each of the cases studied. Based upon this work summarized in the CTR study report the increase in rates is not likely to be a significant factor in the adoption of EVs.
- There was an interest in looking at building electrification sensitivities as part of the study in addition to TE impacts. However, this was not possible because BE load growth was not separable in the forecast used in the HDI and LDI cases. The team recommends that if there is an intertest in BE impacts, forecasts of net load should be developed to allow the various load components to be separated to facilitate analyzing their impacts.

Appendix A. Comparisons of Managed and Unmanaged EV Profiles

Figure A-1—Comparison of Managed and Unmanaged EV Load Profiles for the Year 2025

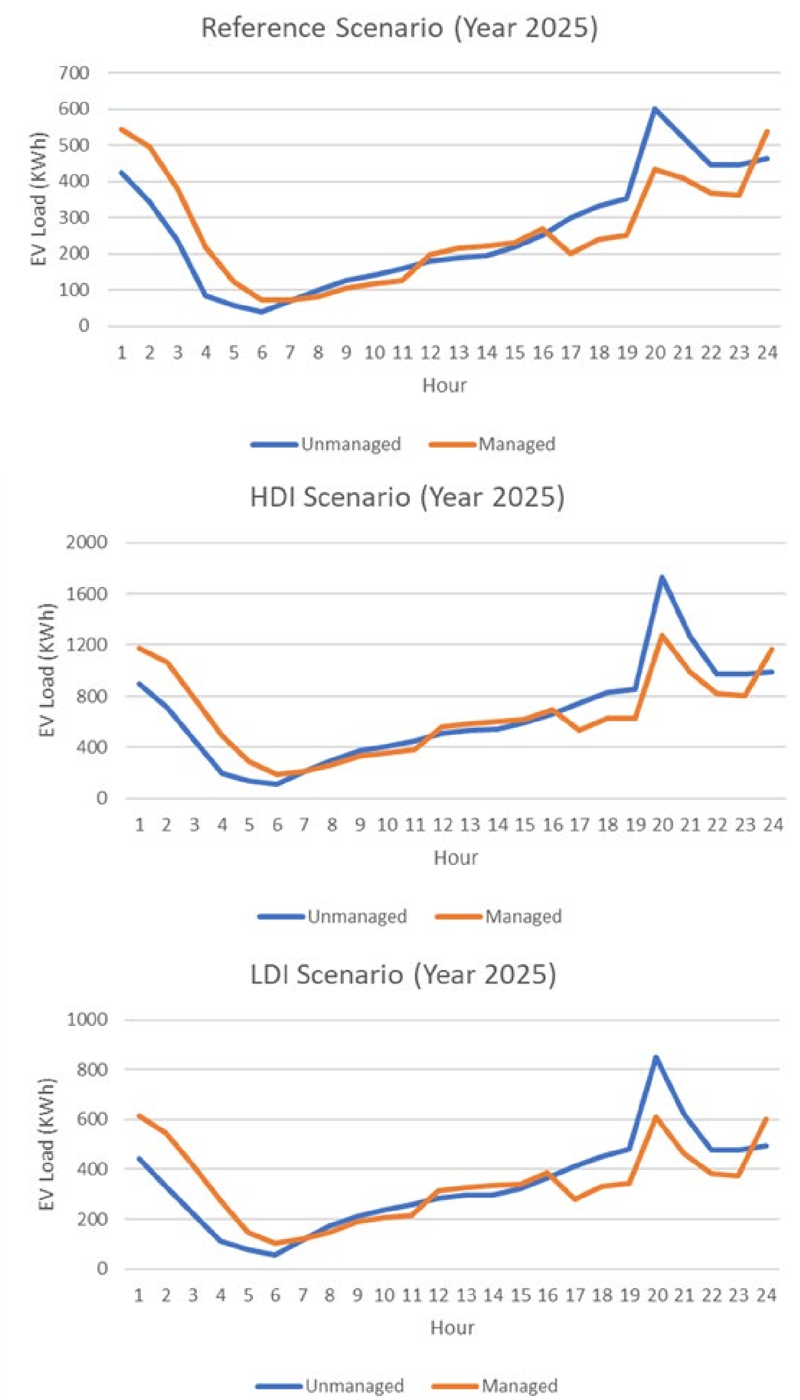
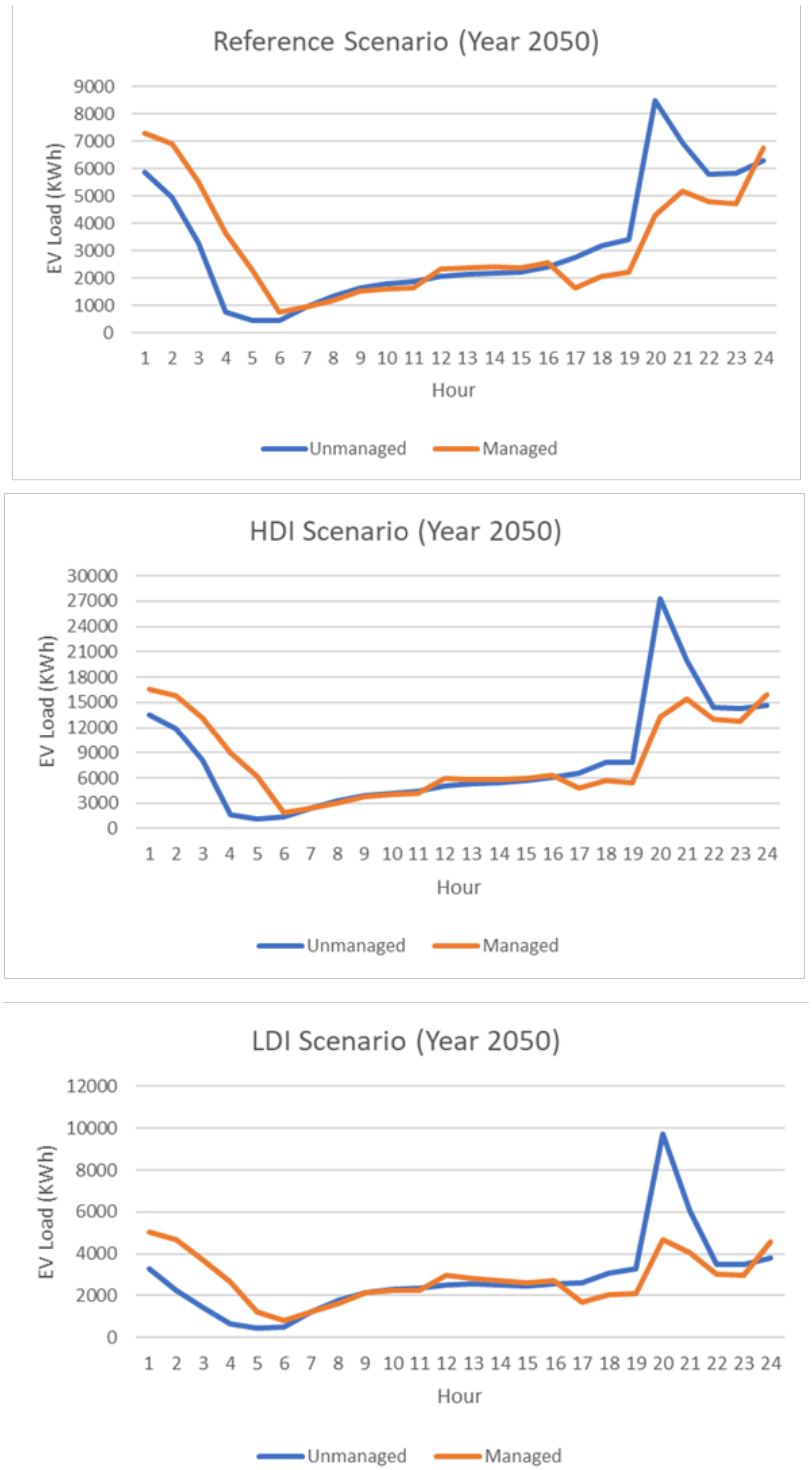


Figure A-2—Comparison of Managed and Unmanaged EV Load Profiles for the Year 2050



Appendix B. ZIP Code Level Estimation of EVs

The light-duty vehicle charger use cases are:

- Residential Level 1 (1.4 kW)
- Residential Level 2 (7.6 kW)[12]
- Commercial Level 2 (7.6 kW)
- Public DCFC (50 kW)

To assign residential charging load across the state's zip codes, Cadmus used vehicle registration data to establish an estimate of the share of residential charging that would occur in each zip code.

- In 2020, Cadmus applied the current share of the *existing EV* population in each zip code.
- In 2050, Cadmus applied the current share of the *entire vehicle* population in each zip code, assuming EVs will be evenly distributed through the population by this time.
- For the intervening years between 2020 and 2050, Cadmus interpolated between these shares.

For energy disbursed from public and workplace chargers, zip code-level assignments depended on existing land use patterns.

- In 2020, Cadmus used the current location of EV chargers based on resources including the Alternative Fuels Data Center and other New York State-specific data sources.
- In 2050, Cadmus used the GAP USGS developed land area for each zip code and applied the assumption that by 2050 EV chargers will be evenly distributed through developed areas.
- For the intervening years between 2020 and 2050, Cadmus interpolated between these shares.

The following vehicle categories summarize the medium- and heavy-duty vehicle sub-sector included in the analysis:

- Light Commercial Trucks (19.2 kW)
- Transit Buses (80 kW)
- School Buses (19.2 kW)
- Refuse Trucks (50 kW)
- Single Unit Short Haul Truck (50 kW)
- Combination Unit Short Haul truck (80 kW)
- Single Unit Long Haul Truck (50 kW)
- Combination Unit Long Haul Truck (150 kW)

The zip code-level disaggregation of energy was based directly on the locations of current vehicle registrations. It was assumed that fleets would charge at a depot or yard located where the vehicle is registered.

Appendix C. Net Peak Loads for National Grid's Representative Circuits

Table C-1: Reference Case—Unmanaged EV Peak Loads

Circuit	Reference Unmanaged TE Summer							Reference Unmanaged TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
4.8, West, R	2.05	2.09	2.12	2.22	2.31	2.40	2.52	1.77	1.80	1.82	1.92	2.05	2.18	2.38
4.8, West, C	1.33	1.28	1.25	1.25	1.27	1.35	1.44	1.14	1.11	1.11	1.16	1.24	1.34	1.49
4.8, West, M	1.53	1.61	1.73	2.11	2.48	2.87	3.28	1.32	1.42	1.52	1.89	2.29	2.71	3.18
4.8, East, R	1.39	1.43	1.48	1.62	1.74	1.84	1.95	1.14	1.19	1.23	1.36	1.50	1.63	1.80
4.8, East, C	0.54	0.53	0.52	0.51	0.50	0.50	0.50	0.42	0.42	0.41	0.41	0.41	0.42	0.44
4.8, East, M	1.37	1.37	1.43	1.61	1.79	1.96	2.15	1.07	1.13	1.18	1.36	1.56	1.76	2.00
4.8, Central, R	1.99	2.02	2.05	2.08	2.10	2.11	2.16	1.52	1.54	1.52	1.55	1.60	1.66	1.78
4.8, Central, C	1.78	1.72	1.77	2.21	2.63	3.13	3.65	1.52	1.57	1.67	2.10	2.55	3.09	3.68
4.8, Central, M	1.16	1.20	1.24	1.32	1.39	1.48	1.59	0.92	0.95	0.97	1.07	1.18	1.30	1.45
4.16, West, R	1.29	1.36	1.44	1.62	1.79	1.94	2.12	0.99	1.04	1.10	1.30	1.51	1.70	1.92
4.16, West, C	1.12	1.08	1.10	1.32	1.54	1.81	2.10	0.89	0.92	0.97	1.19	1.43	1.72	2.05
4.16, West, M	1.29	1.36	1.44	1.69	1.95	2.22	2.51	0.99	1.06	1.14	1.40	1.69	1.98	2.31
4.16, East, R	1.43	1.49	1.56	1.69	1.81	1.89	2.00	1.10	1.14	1.18	1.32	1.46	1.58	1.75
4.16, East, C	1.57	1.53	1.51	1.71	1.90	2.15	2.41	1.11	1.15	1.19	1.39	1.60	1.88	2.20
4.16, East, M	1.39	1.51	1.67	2.13	2.60	3.09	3.60	1.12	1.25	1.38	1.85	2.33	2.85	3.41
4.16, Central, R	1.47	1.50	1.52	1.57	1.62	1.67	1.74	1.16	1.18	1.19	1.26	1.34	1.42	1.54
4.16, Central, C	1.53	1.52	1.54	1.57	1.59	1.63	1.69	1.18	1.18	1.18	1.21	1.26	1.33	1.44
4.16, Central, M	1.13	1.14	1.18	1.26	1.34	1.43	1.52	0.85	0.88	0.90	0.98	1.08	1.19	1.32
13.2, West, R	4.49	4.60	4.72	4.91	5.08	5.23	5.44	3.46	3.51	3.55	3.77	4.03	4.29	4.68
13.2, West, C	2.35	2.26	2.21	2.24	2.41	2.63	2.87	1.92	1.87	1.87	2.04	2.25	2.52	2.86
13.2, West, M	4.31	4.28	4.51	5.23	5.93	6.68	7.47	3.31	3.49	3.67	4.39	5.15	5.98	6.94
13.2, East, R	4.71	4.85	5.01	5.26	5.49	5.67	5.91	3.63	3.72	3.79	4.05	4.36	4.65	5.06
13.2, East, C	4.84	4.64	4.55	4.50	4.51	4.58	4.71	4.64	4.65	4.60	4.62	4.70	4.88	5.22
13.2, East, M	4.85	5.07	5.44	6.45	7.44	8.52	9.65	4.27	4.55	4.83	5.83	6.90	8.07	9.40
13.2, Central, R	5.49	5.57	5.66	5.71	5.73	5.77	5.87	4.35	4.37	4.33	4.38	4.50	4.65	4.96
13.2, Central, C	4.47	4.30	4.23	4.44	4.65	4.93	5.27	3.94	4.00	4.02	4.24	4.51	4.89	5.41
13.2, Central, M	2.89	2.90	3.07	3.57	4.06	4.58	5.14	2.41	2.54	2.66	3.16	3.69	4.28	4.95

Table C-2: Reference Case—Managed EV Peak Loads

Circuit	Reference Managed TE Summer							Reference Managed TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
4.8, West, R	2.05	2.07	2.10	2.13	2.17	2.20	2.26	1.77	1.78	1.79	1.84	1.91	1.98	2.14
4.8, West, C	1.33	1.28	1.25	1.25	1.24	1.24	1.26	1.14	1.11	1.10	1.12	1.15	1.20	1.31
4.8, West, M	1.52	1.57	1.67	1.86	2.05	2.25	2.48	1.32	1.39	1.45	1.64	1.86	2.11	2.48
4.8, East, R	1.38	1.42	1.45	1.52	1.58	1.63	1.76	1.14	1.17	1.19	1.26	1.36	1.52	1.75
4.8, East, C	0.54	0.53	0.52	0.51	0.50	0.50	0.50	0.42	0.42	0.41	0.40	0.40	0.41	0.43
4.8, East, M	1.37	1.36	1.38	1.48	1.57	1.63	1.77	1.06	1.10	1.14	1.23	1.40	1.60	1.84
4.8, Central, R	1.99	2.02	2.04	2.05	2.05	2.06	2.09	1.52	1.53	1.51	1.52	1.54	1.58	1.68
4.8, Central, C	1.78	1.72	1.71	1.92	2.12	2.30	2.59	1.52	1.53	1.60	1.82	2.05	2.33	2.70
4.8, Central, M	1.16	1.19	1.22	1.27	1.32	1.37	1.44	0.92	0.94	0.95	1.00	1.06	1.11	1.22
4.16, West, R	1.29	1.34	1.40	1.52	1.63	1.73	1.91	0.99	1.02	1.06	1.17	1.35	1.57	1.84
4.16, West, C	1.12	1.08	1.07	1.17	1.28	1.38	1.53	0.89	0.90	0.93	1.04	1.16	1.32	1.52
4.16, West, M	1.29	1.34	1.41	1.56	1.71	1.86	2.03	0.99	1.04	1.09	1.23	1.38	1.56	1.83
4.16, East, R	1.43	1.47	1.53	1.61	1.68	1.73	1.82	1.09	1.12	1.15	1.22	1.32	1.48	1.71
4.16, East, C	1.57	1.53	1.51	1.57	1.66	1.73	1.88	1.11	1.13	1.16	1.25	1.36	1.50	1.70
4.16, East, M	1.38	1.46	1.58	1.83	2.07	2.33	2.68	1.11	1.20	1.29	1.54	1.86	2.27	2.71
4.16, Central, R	1.47	1.49	1.51	1.52	1.54	1.56	1.59	1.15	1.17	1.17	1.21	1.26	1.36	1.50
4.16, Central, C	1.53	1.51	1.53	1.54	1.53	1.53	1.55	1.18	1.18	1.17	1.18	1.20	1.23	1.31
4.16, Central, M	1.13	1.14	1.16	1.20	1.24	1.26	1.32	0.85	0.87	0.88	0.92	0.97	1.02	1.14
13.2, West, R	4.48	4.57	4.67	4.79	4.88	4.97	5.12	3.45	3.49	3.49	3.60	3.74	3.89	4.16
13.2, West, C	2.35	2.26	2.21	2.21	2.21	2.23	2.32	1.92	1.87	1.84	1.92	2.02	2.16	2.39
13.2, West, M	4.30	4.25	4.38	4.75	5.09	5.41	5.88	3.29	3.43	3.54	3.91	4.32	4.78	5.53
13.2, East, R	4.70	4.81	4.94	5.09	5.21	5.32	5.49	3.62	3.68	3.70	3.84	4.02	4.19	4.65
13.2, East, C	4.84	4.64	4.55	4.50	4.45	4.43	4.46	4.64	4.64	4.59	4.56	4.59	4.68	4.94
13.2, East, M	4.84	4.97	5.24	5.77	6.27	6.74	7.41	4.26	4.45	4.63	5.15	5.72	6.49	7.57
13.2, Central, R	5.49	5.56	5.63	5.64	5.63	5.63	5.71	4.34	4.36	4.31	4.30	4.36	4.46	4.73
13.2, Central, C	4.47	4.30	4.24	4.26	4.33	4.38	4.48	3.94	3.98	3.98	4.06	4.19	4.35	4.73
13.2, Central, M	2.89	2.85	2.98	3.23	3.47	3.67	3.99	2.40	2.49	2.57	2.82	3.10	3.41	3.92

Table C-3: Reference Case—No Transportation Electrification (TE) Peak Loads

Circuit	Reference No TE Summer							Reference No TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
4.8, West, R	2.04	2.05	2.05	2.02	1.97	1.94	1.94	1.76	1.76	1.73	1.69	1.68	1.70	1.78
4.8, West, C	1.33	1.28	1.25	1.23	1.21	1.20	1.21	1.14	1.11	1.07	1.05	1.06	1.08	1.14
4.8, West, M	1.51	1.52	1.52	1.49	1.46	1.44	1.44	1.30	1.30	1.28	1.25	1.25	1.26	1.32
4.8, East, R	1.37	1.38	1.38	1.35	1.32	1.31	1.31	1.13	1.13	1.11	1.08	1.08	1.09	1.14
4.8, East, C	0.54	0.53	0.52	0.51	0.50	0.50	0.50	0.42	0.42	0.41	0.40	0.40	0.40	0.42
4.8, East, M	1.36	1.33	1.31	1.29	1.27	1.25	1.26	1.05	1.05	1.03	1.01	1.01	1.02	1.07
4.8, Central, R	1.98	2.00	2.01	1.99	1.95	1.93	1.93	1.52	1.52	1.49	1.46	1.45	1.47	1.54
4.8, Central, C	1.78	1.70	1.66	1.64	1.62	1.60	1.61	1.51	1.46	1.42	1.40	1.40	1.43	1.52
4.8, Central, M	1.15	1.16	1.17	1.16	1.13	1.12	1.12	0.92	0.91	0.90	0.88	0.88	0.89	0.93
4.16, West, R	1.27	1.28	1.29	1.28	1.25	1.24	1.24	0.97	0.97	0.95	0.93	0.93	0.94	0.99
4.16, West, C	1.11	1.07	1.05	1.03	1.02	1.01	1.01	0.88	0.86	0.84	0.83	0.82	0.84	0.90
4.16, West, M	1.27	1.28	1.29	1.28	1.25	1.24	1.24	0.98	0.98	0.96	0.94	0.94	0.95	0.99
4.16, East, R	1.41	1.42	1.44	1.42	1.39	1.37	1.38	1.08	1.08	1.06	1.04	1.03	1.04	1.10
4.16, East, C	1.57	1.52	1.49	1.47	1.45	1.44	1.44	1.11	1.11	1.09	1.06	1.05	1.06	1.13
4.16, East, M	1.37	1.37	1.37	1.35	1.32	1.30	1.30	1.09	1.09	1.07	1.05	1.04	1.06	1.11
4.16, Central, R	1.46	1.47	1.47	1.44	1.41	1.39	1.39	1.15	1.15	1.13	1.11	1.10	1.11	1.17
4.16, Central, C	1.53	1.51	1.51	1.49	1.46	1.44	1.44	1.18	1.18	1.15	1.13	1.13	1.14	1.20
4.16, Central, M	1.13	1.12	1.12	1.10	1.08	1.07	1.06	0.85	0.85	0.83	0.81	0.81	0.82	0.86
13.2, West, R	4.46	4.50	4.53	4.47	4.39	4.34	4.35	3.44	3.43	3.37	3.29	3.28	3.32	3.48
13.2, West, C	2.35	2.25	2.19	2.17	2.14	2.12	2.13	1.92	1.86	1.80	1.78	1.78	1.81	1.92
13.2, West, M	4.28	4.18	4.14	4.06	3.99	3.94	3.95	3.27	3.27	3.20	3.14	3.12	3.16	3.32
13.2, East, R	4.67	4.71	4.74	4.68	4.59	4.54	4.55	3.60	3.59	3.53	3.45	3.43	3.47	3.64
13.2, East, C	4.84	4.63	4.54	4.48	4.41	4.38	4.39	4.64	4.64	4.55	4.47	4.44	4.53	4.83
13.2, East, M	4.80	4.82	4.82	4.74	4.63	4.57	4.57	4.21	4.21	4.13	4.05	4.03	4.07	4.28
13.2, Central, R	5.47	5.52	5.56	5.49	5.38	5.32	5.33	4.33	4.33	4.25	4.15	4.13	4.18	4.39
13.2, Central, C	4.47	4.28	4.20	4.15	4.09	4.06	4.07	3.94	3.93	3.86	3.79	3.77	3.82	4.07
13.2, Central, M	2.87	2.81	2.80	2.75	2.69	2.65	2.65	2.38	2.38	2.34	2.29	2.28	2.31	2.42

Table C-4: HDI Case—Unmanaged EV Peak Loads

Circuit	HDI Unmanaged TE Summer							HDI Unmanaged TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
4.8, West, R	2.01	1.94	1.96	2.37	2.81	3.16	3.56	1.69	1.78	1.95	2.48	3.02	3.45	3.89
4.8, West, C	1.30	1.16	1.09	1.44	1.80	2.23	2.68	1.09	1.09	1.20	1.62	2.04	2.52	3.00
4.8, West, M	1.52	1.73	2.02	3.56	5.12	6.77	8.46	1.32	1.61	2.02	3.64	5.27	6.99	8.70
4.8, East, R	1.37	1.38	1.45	1.83	2.23	2.49	2.79	1.11	1.21	1.39	1.84	2.30	2.62	2.93
4.8, East, C	0.53	0.47	0.44	0.46	0.48	0.51	0.56	0.40	0.39	0.41	0.46	0.51	0.56	0.61
4.8, East, M	1.35	1.36	1.48	2.13	2.79	3.38	4.00	1.04	1.19	1.42	2.13	2.85	3.49	4.14
4.8, Central, R	1.94	1.86	1.80	1.94	2.11	2.23	2.39	1.45	1.47	1.57	1.82	2.09	2.28	2.47
4.8, Central, C	1.75	1.83	2.20	4.27	6.37	8.81	11.28	1.46	1.81	2.31	4.48	6.66	9.17	11.68
4.8, Central, M	1.14	1.14	1.17	1.58	2.01	2.43	2.87	0.89	0.97	1.11	1.58	2.06	2.52	2.97
4.16, West, R	1.28	1.34	1.45	2.07	2.71	3.20	3.73	0.97	1.12	1.34	2.02	2.71	3.25	3.79
4.16, West, C	1.09	1.11	1.29	2.38	3.49	4.81	6.15	0.86	1.04	1.30	2.45	3.61	4.97	6.33
4.16, West, M	1.29	1.40	1.60	2.66	3.74	4.84	5.98	0.99	1.19	1.49	2.61	3.74	4.89	6.05
4.16, East, R	1.41	1.44	1.49	1.83	2.21	2.44	2.71	1.06	1.17	1.35	1.78	2.21	2.49	2.77
4.16, East, C	1.54	1.46	1.60	2.56	3.53	4.66	5.81	1.08	1.24	1.48	2.51	3.55	4.72	5.89
4.16, East, M	1.41	1.70	2.10	3.88	5.69	7.54	9.43	1.14	1.51	2.01	3.86	5.73	7.63	9.53
4.16, Central, R	1.44	1.40	1.38	1.61	1.86	2.03	2.23	1.11	1.16	1.28	1.58	1.90	2.12	2.33
4.16, Central, C	1.49	1.41	1.38	1.63	1.89	2.20	2.54	1.12	1.15	1.24	1.56	1.89	2.25	2.60
4.16, Central, M	1.11	1.10	1.14	1.50	1.89	2.25	2.63	0.82	0.89	1.02	1.44	1.87	2.26	2.66
13.2, West, R	4.40	4.30	4.27	5.00	5.85	6.52	7.28	3.31	3.47	3.83	4.85	5.89	6.71	7.53
13.2, West, C	2.29	2.05	2.05	3.00	3.97	5.13	6.33	1.83	1.88	2.13	3.20	4.27	5.51	6.76
13.2, West, M	4.23	4.39	4.90	7.89	10.93	14.15	17.44	3.25	3.82	4.65	7.84	11.06	14.42	17.78
13.2, East, R	4.63	4.58	4.61	5.35	6.20	6.78	7.45	3.49	3.70	4.12	5.17	6.25	6.98	7.72
13.2, East, C	4.71	4.18	3.92	4.40	4.93	5.53	6.23	4.41	4.45	4.69	5.47	6.29	7.12	7.96
13.2, East, M	4.80	5.34	6.12	10.11	14.15	18.30	22.55	4.22	5.02	6.19	10.45	14.73	19.07	23.41
13.2, Central, R	5.36	5.11	4.93	5.29	5.71	6.02	6.44	4.14	4.18	4.43	5.09	5.79	6.30	6.82
13.2, Central, C	4.36	3.94	4.00	5.35	6.74	8.34	10.03	3.78	3.99	4.39	6.00	7.62	9.41	11.21
13.2, Central, M	2.84	3.01	3.38	5.58	7.81	10.19	12.62	2.37	2.77	3.37	5.72	8.09	10.57	13.06

Table C-5: HDI Case—Managed EV Peak Loads

Circuit	HDI Managed TE Summer							HDI Managed TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
4.8, West, R	2.01	1.92	1.88	2.13	2.40	2.55	2.84	1.69	1.74	1.88	2.24	2.61	2.84	3.13
4.8, West, C	1.30	1.16	1.06	1.25	1.45	1.59	1.87	1.09	1.07	1.16	1.42	1.69	1.89	2.22
4.8, West, M	1.50	1.63	1.82	2.67	3.55	4.24	5.32	1.30	1.51	1.82	2.76	3.70	4.44	5.55
4.8, East, R	1.36	1.33	1.36	1.59	1.95	2.18	2.45	1.10	1.17	1.30	1.60	2.01	2.30	2.59
4.8, East, C	0.53	0.47	0.44	0.45	0.47	0.48	0.51	0.40	0.39	0.41	0.45	0.49	0.53	0.56
4.8, East, M	1.35	1.30	1.37	1.74	2.12	2.42	2.85	1.03	1.14	1.31	1.75	2.19	2.63	3.09
4.8, Central, R	1.94	1.85	1.77	1.88	2.01	2.11	2.25	1.45	1.46	1.54	1.73	1.94	2.08	2.22
4.8, Central, C	1.75	1.71	1.96	3.08	4.22	5.13	6.69	1.46	1.70	2.07	3.29	4.51	5.53	7.13
4.8, Central, M	1.14	1.12	1.12	1.34	1.59	1.84	2.14	0.88	0.94	1.05	1.34	1.64	1.83	2.14
4.16, West, R	1.28	1.30	1.35	1.71	2.24	2.61	3.02	0.95	1.06	1.22	1.65	2.20	2.64	3.08
4.16, West, C	1.09	1.05	1.17	1.76	2.37	2.86	3.72	0.85	0.98	1.18	1.83	2.48	3.03	3.91
4.16, West, M	1.28	1.32	1.45	2.04	2.65	3.20	3.94	0.97	1.12	1.34	2.00	2.66	3.15	3.90
4.16, East, R	1.41	1.40	1.42	1.65	2.01	2.23	2.46	1.05	1.12	1.26	1.54	1.96	2.24	2.52
4.16, East, C	1.54	1.41	1.49	2.01	2.55	2.94	3.67	1.07	1.18	1.37	1.97	2.57	3.00	3.75
4.16, East, M	1.38	1.57	1.84	2.83	3.84	4.58	5.77	1.11	1.38	1.75	2.81	3.88	4.65	5.86
4.16, Central, R	1.44	1.38	1.33	1.47	1.64	1.73	1.90	1.11	1.14	1.23	1.45	1.74	1.93	2.12
4.16, Central, C	1.49	1.40	1.35	1.49	1.65	1.76	1.98	1.12	1.14	1.21	1.43	1.65	1.81	2.04
4.16, Central, M	1.11	1.07	1.08	1.29	1.52	1.67	1.92	0.82	0.87	0.96	1.22	1.49	1.67	1.94
13.2, West, R	4.39	4.25	4.16	4.64	5.18	5.65	6.21	3.30	3.40	3.68	4.38	5.10	5.54	6.06
13.2, West, C	2.29	2.05	1.95	2.47	3.01	3.39	4.16	1.83	1.83	2.03	2.66	3.31	3.83	4.65
13.2, West, M	4.22	4.19	4.50	6.17	7.88	9.20	11.34	3.21	3.61	4.25	6.12	8.01	9.45	11.65
13.2, East, R	4.61	4.50	4.46	4.97	5.54	5.96	6.48	3.47	3.60	3.93	4.66	5.41	5.86	6.48
13.2, East, C	4.71	4.18	3.87	4.14	4.47	4.71	5.04	4.41	4.43	4.64	5.22	5.83	6.30	6.82
13.2, East, M	4.77	5.06	5.55	7.77	10.06	11.64	14.35	4.16	4.74	5.62	8.11	10.63	12.39	15.18
13.2, Central, R	5.36	5.09	4.87	5.13	5.46	5.72	6.09	4.14	4.15	4.35	4.88	5.43	5.81	6.20
13.2, Central, C	4.36	3.91	3.85	4.59	5.37	5.89	6.94	3.77	3.91	4.24	5.24	6.26	7.00	8.22
13.2, Central, M	2.83	2.86	3.10	4.31	5.55	6.49	8.05	2.34	2.63	3.09	4.45	5.83	6.88	8.50

Table C-6: HDI Case—No Transportation Electrification (TE) Peak Loads

Circuit	HDI No TE Summer							HDI No TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
4.8, West, R	1.99	1.85	1.73	1.74	1.78	1.82	1.91	1.67	1.66	1.71	1.83	1.97	2.09	2.21
4.8, West, C	1.30	1.15	1.04	1.05	1.09	1.13	1.19	1.08	1.04	1.06	1.15	1.25	1.34	1.42
4.8, West, M	1.47	1.37	1.28	1.29	1.32	1.35	1.41	1.24	1.23	1.26	1.36	1.46	1.55	1.64
4.8, East, R	1.34	1.24	1.16	1.17	1.20	1.23	1.28	1.07	1.06	1.09	1.17	1.26	1.34	1.42
4.8, East, C	0.53	0.47	0.43	0.44	0.45	0.47	0.49	0.40	0.39	0.40	0.43	0.47	0.50	0.52
4.8, East, M	1.33	1.20	1.10	1.11	1.15	1.18	1.24	1.00	0.99	1.02	1.10	1.18	1.25	1.32
4.8, Central, R	1.93	1.81	1.70	1.72	1.77	1.81	1.89	1.44	1.43	1.47	1.58	1.70	1.80	1.91
4.8, Central, C	1.73	1.53	1.38	1.40	1.46	1.51	1.59	1.43	1.38	1.40	1.52	1.66	1.77	1.88
4.8, Central, M	1.12	1.05	0.99	1.00	1.03	1.05	1.10	0.87	0.86	0.89	0.95	1.03	1.09	1.15
4.16, West, R	1.24	1.16	1.09	1.11	1.13	1.16	1.21	0.92	0.92	0.94	1.01	1.09	1.15	1.22
4.16, West, C	1.09	0.96	0.87	0.89	0.92	0.95	1.00	0.84	0.81	0.84	0.90	0.97	1.04	1.10
4.16, West, M	1.24	1.16	1.09	1.11	1.13	1.16	1.21	0.93	0.92	0.95	1.02	1.10	1.17	1.23
4.16, East, R	1.38	1.29	1.21	1.23	1.26	1.29	1.35	1.03	1.02	1.05	1.13	1.21	1.28	1.36
4.16, East, C	1.53	1.36	1.24	1.26	1.31	1.35	1.42	1.05	1.04	1.08	1.16	1.25	1.33	1.40
4.16, East, M	1.33	1.24	1.16	1.17	1.19	1.22	1.28	1.04	1.03	1.06	1.14	1.22	1.30	1.37
4.16, Central, R	1.43	1.33	1.24	1.25	1.28	1.31	1.37	1.09	1.08	1.12	1.20	1.29	1.37	1.45
4.16, Central, C	1.49	1.37	1.28	1.29	1.32	1.35	1.41	1.12	1.11	1.14	1.23	1.32	1.40	1.48
4.16, Central, M	1.10	1.02	0.95	0.96	0.98	1.00	1.04	0.80	0.80	0.82	0.88	0.95	1.01	1.06
13.2, West, R	4.35	4.07	3.83	3.88	3.98	4.07	4.25	3.26	3.24	3.33	3.58	3.85	4.08	4.31
13.2, West, C	2.29	2.02	1.82	1.85	1.93	1.99	2.10	1.82	1.75	1.78	1.94	2.11	2.25	2.40
13.2, West, M	4.17	3.77	3.49	3.51	3.61	3.71	3.89	3.10	3.08	3.17	3.40	3.66	3.88	4.11
13.2, East, R	4.55	4.26	4.01	4.06	4.16	4.26	4.45	3.41	3.39	3.49	3.75	4.03	4.27	4.51
13.2, East, C	4.71	4.16	3.80	3.84	3.99	4.11	4.33	4.41	4.37	4.50	4.84	5.21	5.52	5.84
13.2, East, M	4.67	4.36	4.07	4.10	4.20	4.29	4.48	4.00	3.97	4.09	4.39	4.72	5.00	5.29
13.2, Central, R	5.33	5.00	4.70	4.76	4.88	4.99	5.22	4.12	4.08	4.20	4.51	4.85	5.14	5.44
13.2, Central, C	4.35	3.86	3.52	3.56	3.70	3.81	4.02	3.74	3.71	3.82	4.10	4.42	4.68	4.96
13.2, Central, M	2.80	2.53	2.36	2.38	2.43	2.49	2.61	2.26	2.25	2.31	2.48	2.67	2.84	3.00

Table C-7: LDI Case—Unmanaged EV Peak Loads

Circuit	LDI Unmanaged TE Summer							LDI Unmanaged TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
4.8, West, R	1.99	1.88	1.81	2.02	2.26	2.34	2.41	1.78	1.74	1.79	2.08	2.39	2.56	2.68
4.8, West, C	1.30	1.14	1.02	1.12	1.27	1.38	1.50	1.15	1.06	1.08	1.26	1.46	1.63	1.78
4.8, West, M	1.49	1.51	1.60	2.25	2.92	3.30	3.68	1.34	1.42	1.58	2.29	3.02	3.46	3.88
4.8, East, R	1.35	1.30	1.30	1.51	1.74	1.79	1.83	1.15	1.16	1.23	1.49	1.77	1.87	1.94
4.8, East, C	0.52	0.47	0.42	0.43	0.45	0.46	0.47	0.42	0.40	0.39	0.42	0.45	0.49	0.51
4.8, East, M	1.34	1.24	1.26	1.58	1.90	2.03	2.16	1.08	1.11	1.20	1.55	1.92	2.10	2.26
4.8, Central, R	1.93	1.82	1.72	1.82	1.93	1.96	1.99	1.53	1.48	1.48	1.64	1.82	1.93	2.00
4.8, Central, C	1.73	1.55	1.65	2.47	3.30	3.90	4.50	1.53	1.57	1.74	2.63	3.53	4.20	4.85
4.8, Central, M	1.13	1.08	1.05	1.24	1.44	1.54	1.63	0.93	0.93	0.97	1.21	1.45	1.59	1.71
4.16, West, R	1.26	1.25	1.26	1.57	1.91	2.00	2.08	1.00	1.04	1.13	1.50	1.88	2.01	2.12
4.16, West, C	1.09	0.97	0.99	1.41	1.84	2.17	2.50	0.89	0.91	1.00	1.45	1.92	2.29	2.64
4.16, West, M	1.26	1.24	1.29	1.76	2.23	2.49	2.73	1.01	1.07	1.18	1.69	2.20	2.50	2.77
4.16, East, R	1.39	1.36	1.35	1.55	1.76	1.79	1.82	1.11	1.12	1.19	1.44	1.72	1.80	1.86
4.16, East, C	1.53	1.37	1.33	1.71	2.10	2.39	2.68	1.12	1.13	1.20	1.63	2.07	2.41	2.74
4.16, East, M	1.36	1.44	1.58	2.35	3.14	3.58	4.01	1.14	1.27	1.48	2.30	3.14	3.62	4.09
4.16, Central, R	1.43	1.35	1.29	1.43	1.58	1.62	1.64	1.16	1.15	1.17	1.37	1.58	1.66	1.72
4.16, Central, C	1.48	1.36	1.29	1.40	1.51	1.60	1.69	1.18	1.14	1.14	1.30	1.46	1.61	1.73
4.16, Central, M	1.10	1.04	1.02	1.20	1.39	1.47	1.55	0.86	0.86	0.89	1.11	1.33	1.45	1.56
13.2, West, R	4.36	4.15	4.00	4.38	4.79	4.94	5.08	3.48	3.41	3.49	4.07	4.70	5.01	5.24
13.2, West, C	2.28	2.01	1.81	2.15	2.53	2.83	3.12	1.93	1.80	1.84	2.28	2.75	3.14	3.49
13.2, West, M	4.19	3.95	4.05	5.33	6.64	7.40	8.13	3.34	3.47	3.76	5.18	6.65	7.55	8.38
13.2, East, R	4.58	4.39	4.27	4.72	5.20	5.29	5.36	3.65	3.60	3.73	4.36	5.04	5.33	5.52
13.2, East, C	4.69	4.11	3.73	3.93	4.17	4.37	4.55	4.66	4.46	4.43	4.84	5.31	5.75	6.08
13.2, East, M	4.72	4.73	4.94	6.68	8.45	9.45	10.42	4.32	4.52	4.96	6.88	8.85	10.05	11.15
13.2, Central, R	5.33	5.01	4.73	4.97	5.25	5.34	5.42	4.37	4.20	4.19	4.62	5.10	5.40	5.61
13.2, Central, C	4.34	3.83	3.60	4.14	4.72	5.15	5.56	3.96	3.87	3.94	4.66	5.42	6.05	6.59
13.2, Central, M	2.81	2.69	2.77	3.72	4.69	5.25	5.80	2.44	2.52	2.73	3.78	4.86	5.54	6.17

Table C-8: LDI Case—Managed EV Peak Loads

Circuit	LDI Managed TE Summer							LDI Managed TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
4.8, West, R	1.99	1.87	1.77	1.90	2.04	2.08	2.11	1.78	1.72	1.74	1.95	2.18	2.30	2.38
4.8, West, C	1.30	1.14	1.02	1.06	1.13	1.16	1.20	1.15	1.06	1.06	1.18	1.31	1.41	1.47
4.8, West, M	1.48	1.46	1.49	1.85	2.21	2.30	2.39	1.33	1.37	1.48	1.89	2.31	2.47	2.59
4.8, East, R	1.35	1.28	1.24	1.38	1.52	1.54	1.55	1.15	1.13	1.17	1.36	1.55	1.62	1.67
4.8, East, C	0.52	0.47	0.42	0.43	0.44	0.45	0.46	0.42	0.40	0.39	0.42	0.45	0.48	0.50
4.8, East, M	1.34	1.22	1.20	1.38	1.57	1.61	1.64	1.07	1.08	1.13	1.36	1.59	1.68	1.74
4.8, Central, R	1.93	1.81	1.71	1.78	1.86	1.89	1.92	1.53	1.47	1.46	1.59	1.74	1.84	1.90
4.8, Central, C	1.73	1.55	1.54	1.96	2.39	2.53	2.66	1.53	1.52	1.63	2.12	2.62	2.83	3.01
4.8, Central, M	1.13	1.07	1.03	1.13	1.24	1.27	1.31	0.93	0.91	0.94	1.09	1.25	1.32	1.37
4.16, West, R	1.25	1.22	1.21	1.39	1.62	1.64	1.65	0.99	1.00	1.07	1.30	1.55	1.61	1.66
4.16, West, C	1.09	0.97	0.94	1.16	1.38	1.46	1.53	0.89	0.89	0.94	1.19	1.46	1.58	1.68
4.16, West, M	1.25	1.22	1.22	1.47	1.74	1.80	1.85	1.00	1.03	1.10	1.40	1.71	1.81	1.90
4.16, East, R	1.39	1.34	1.31	1.44	1.59	1.61	1.63	1.10	1.09	1.13	1.31	1.50	1.57	1.61
4.16, East, C	1.53	1.37	1.28	1.48	1.68	1.76	1.84	1.12	1.11	1.15	1.40	1.66	1.79	1.89
4.16, East, M	1.35	1.37	1.45	1.87	2.30	2.40	2.49	1.13	1.20	1.35	1.81	2.29	2.44	2.57
4.16, Central, R	1.43	1.34	1.27	1.35	1.45	1.47	1.48	1.16	1.13	1.15	1.29	1.45	1.51	1.56
4.16, Central, C	1.48	1.36	1.28	1.34	1.41	1.44	1.48	1.18	1.13	1.13	1.24	1.36	1.45	1.52
4.16, Central, M	1.10	1.03	0.99	1.09	1.20	1.23	1.25	0.86	0.84	0.86	1.00	1.15	1.22	1.26
13.2, West, R	4.36	4.12	3.93	4.19	4.49	4.58	4.66	3.47	3.36	3.41	3.82	4.27	4.50	4.66
13.2, West, C	2.28	2.01	1.81	1.93	2.13	2.22	2.30	1.93	1.80	1.80	2.06	2.36	2.53	2.66
13.2, West, M	4.18	3.85	3.84	4.54	5.27	5.46	5.64	3.32	3.36	3.56	4.40	5.28	5.62	5.88
13.2, East, R	4.57	4.34	4.18	4.49	4.83	4.91	4.97	3.64	3.55	3.62	4.07	4.57	4.80	4.94
13.2, East, C	4.69	4.11	3.72	3.82	3.97	4.07	4.15	4.66	4.45	4.41	4.73	5.12	5.46	5.68
13.2, East, M	4.71	4.59	4.65	5.60	6.58	6.83	7.05	4.29	4.38	4.67	5.80	6.98	7.43	7.78
13.2, Central, R	5.33	4.99	4.70	4.87	5.09	5.18	5.25	4.36	4.19	4.15	4.49	4.89	5.17	5.35
13.2, Central, C	4.34	3.83	3.53	3.82	4.14	4.28	4.40	3.96	3.84	3.87	4.33	4.85	5.18	5.43
13.2, Central, M	2.80	2.62	2.62	3.14	3.67	3.81	3.93	2.42	2.45	2.59	3.20	3.85	4.10	4.29

Table C-9: LDI Case—No Transportation Electrification (TE) Peak Loads

Circuit	LDI No TE Summer							LDI No TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
4.8, West, R	1.98	1.83	1.69	1.70	1.73	1.77	1.79	1.77	1.68	1.65	1.74	1.85	1.96	2.04
4.8, West, C	1.29	1.13	1.01	1.03	1.06	1.09	1.12	1.15	1.06	1.03	1.09	1.17	1.26	1.31
4.8, West, M	1.47	1.36	1.25	1.26	1.28	1.31	1.33	1.31	1.25	1.22	1.29	1.37	1.46	1.51
4.8, East, R	1.33	1.23	1.14	1.15	1.17	1.19	1.20	1.13	1.08	1.06	1.11	1.18	1.26	1.31
4.8, East, C	0.52	0.47	0.42	0.43	0.44	0.45	0.46	0.42	0.40	0.39	0.41	0.44	0.47	0.48
4.8, East, M	1.32	1.18	1.07	1.08	1.11	1.14	1.16	1.06	1.01	0.99	1.04	1.11	1.18	1.22
4.8, Central, R	1.92	1.79	1.67	1.69	1.72	1.75	1.78	1.53	1.45	1.43	1.50	1.60	1.70	1.76
4.8, Central, C	1.72	1.51	1.34	1.37	1.41	1.46	1.49	1.52	1.40	1.36	1.44	1.55	1.66	1.74
4.8, Central, M	1.12	1.04	0.97	0.98	1.00	1.02	1.03	0.92	0.87	0.86	0.90	0.96	1.02	1.06
4.16, West, R	1.23	1.15	1.07	1.08	1.10	1.12	1.14	0.98	0.93	0.91	0.96	1.02	1.09	1.13
4.16, West, C	1.08	0.95	0.85	0.87	0.89	0.92	0.94	0.89	0.82	0.81	0.85	0.91	0.97	1.02
4.16, West, M	1.23	1.15	1.07	1.08	1.10	1.12	1.14	0.99	0.94	0.92	0.97	1.03	1.10	1.14
4.16, East, R	1.37	1.27	1.19	1.20	1.22	1.25	1.27	1.09	1.03	1.02	1.07	1.14	1.21	1.25
4.16, East, C	1.52	1.35	1.21	1.23	1.27	1.30	1.33	1.11	1.06	1.04	1.10	1.17	1.25	1.30
4.16, East, M	1.33	1.22	1.13	1.14	1.16	1.18	1.20	1.10	1.04	1.02	1.08	1.15	1.22	1.27
4.16, Central, R	1.42	1.31	1.21	1.22	1.24	1.27	1.28	1.15	1.10	1.08	1.14	1.21	1.29	1.34
4.16, Central, C	1.48	1.35	1.25	1.26	1.28	1.31	1.33	1.18	1.12	1.11	1.16	1.24	1.32	1.37
4.16, Central, M	1.09	1.00	0.93	0.93	0.95	0.97	0.98	0.85	0.81	0.79	0.84	0.89	0.95	0.98
13.2, West, R	4.33	4.02	3.75	3.79	3.87	3.94	4.00	3.45	3.28	3.22	3.39	3.61	3.84	3.98
13.2, West, C	2.28	1.99	1.78	1.81	1.87	1.92	1.96	1.93	1.78	1.72	1.83	1.97	2.12	2.21
13.2, West, M	4.15	3.72	3.41	3.44	3.50	3.58	3.65	3.28	3.12	3.07	3.23	3.44	3.65	3.79
13.2, East, R	4.53	4.21	3.92	3.97	4.05	4.13	4.19	3.61	3.44	3.37	3.55	3.78	4.01	4.17
13.2, East, C	4.69	4.11	3.71	3.75	3.87	3.98	4.06	4.66	4.43	4.36	4.59	4.89	5.20	5.40
13.2, East, M	4.66	4.30	3.98	4.01	4.08	4.15	4.21	4.23	4.03	3.95	4.16	4.43	4.71	4.89
13.2, Central, R	5.31	4.94	4.60	4.65	4.75	4.84	4.91	4.35	4.14	4.07	4.28	4.55	4.84	5.02
13.2, Central, C	4.33	3.80	3.43	3.47	3.58	3.68	3.76	3.95	3.76	3.69	3.89	4.14	4.41	4.58
13.2, Central, M	2.79	2.50	2.31	2.32	2.36	2.41	2.45	2.39	2.28	2.24	2.35	2.51	2.67	2.77

Appendix D. Net Peak Load for Con Edison's Representative Networks

Table D-1: Reference Scenario—Unmanaged, Managed and No TE Peak Loads

Network	Reference Unmanaged TE Summer							Reference Unmanaged TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
Central Bronx	193.01	194.06	198.39	208.63	218.72	229.01	238.45	114.62	119.11	126.43	140.60	155.49	172.54	191.95
Grand Central	161.03	163.43	169.81	177.76	184.31	187.48	189.53	116.07	122.32	128.71	137.56	146.98	156.54	168.99
Sheepshead Bay	162.01	162.94	166.39	175.83	185.65	195.76	205.27	90.46	94.24	100.45	113.18	126.53	142.17	159.62
Wainwright	85.07	85.87	87.93	92.20	98.16	104.06	109.61	31.01	33.70	36.73	43.23	49.91	57.30	65.33
Yorkville	289.06	290.78	298.66	313.28	326.56	336.62	345.04	175.58	182.91	192.27	207.37	225.17	244.52	267.71

Table D-2: HDI Scenario—Unmanaged, Managed and No TE Peak Loads

Network	HDI Unmanaged TE Summer							HDI Unmanaged TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
Central Bronx	193.03	188.23	187.30	208.19	231.57	255.73	283.19	114.65	119.19	132.12	163.88	197.58	229.32	261.17
Grand Central	161.04	149.12	140.92	141.12	144.68	149.86	159.59	115.96	116.44	130.16	149.27	171.38	190.62	209.96
Sheepshead Bay	162.08	160.30	160.96	180.78	202.50	224.52	249.04	90.40	95.20	105.87	133.44	162.41	189.63	216.94
Wainwright	85.03	83.74	83.27	95.39	108.72	120.75	134.19	30.96	35.32	41.46	56.83	72.74	86.33	99.95
Yorkville	289.01	277.15	270.65	287.23	308.32	329.97	357.65	175.48	178.03	194.49	230.95	270.92	306.39	342.05
Network	**HDI Managed TE Summer**							**HDI Managed TE Winter**						
	2021	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2021**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Central Bronx	193.03	187.43	184.41	195.92	209.92	221.82	240.76	114.65	117.74	129.22	151.60	175.93	193.75	215.73
Grand Central	161.04	149.08	140.84	140.96	144.52	149.87	159.71	115.96	116.45	130.18	149.31	171.45	190.72	210.08
Sheepshead Bay	162.08	158.94	157.94	169.04	182.05	194.43	211.51	90.40	93.68	102.85	121.71	141.96	157.49	176.46
Wainwright	85.03	83.12	82.03	88.38	96.86	102.05	108.90	30.96	34.24	39.30	49.82	60.88	67.63	75.25
Yorkville	289.01	275.94	268.25	277.46	291.18	302.39	321.37	175.48	177.62	193.24	221.17	253.77	278.81	304.03
Network	**HDI No TE Summer**							**HDI No TE Winter**						
	2021	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2021**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Central Bronx	193.03	184.39	178.26	177.83	179.87	183.48	190.39	114.65	114.67	121.95	132.15	144.36	155.43	166.67
Grand Central	161.04	148.86	140.42	140.06	143.06	148.16	157.82	115.96	116.14	129.60	148.08	169.56	188.80	208.14
Sheepshead Bay	162.08	155.54	150.87	150.51	152.02	154.72	159.93	90.40	90.37	95.40	102.49	111.06	118.85	126.73
Wainwright	85.03	81.03	78.08	77.73	78.54	80.07	83.10	30.96	30.99	33.03	35.88	39.26	42.31	45.40
Yorkville	289.01	272.99	261.18	260.44	264.26	270.87	283.54	175.48	175.63	189.47	208.82	232.56	253.81	275.17

Table D-3: LDI Scenario—Unmanaged, Managed and No TE Peak Loads

Network	LDI Unmanaged TE Summer							LDI Unmanaged TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
Central Bronx	192.97	184.44	178.43	185.19	195.03	202.88	211.16	114.57	110.60	113.88	129.55	148.20	163.93	176.92
Grand Central	160.98	146.46	135.80	132.57	133.29	136.16	139.56	115.96	106.75	108.86	120.28	136.47	153.34	165.47
Sheepshead Bay	162.01	156.34	152.69	160.22	169.85	177.02	184.53	90.37	88.33	91.40	105.17	121.05	133.73	144.48
Wainwright	85.00	81.64	79.26	82.11	87.92	91.12	94.52	31.03	31.71	33.94	41.41	49.69	54.83	59.22
Yorkville	289.02	271.38	259.37	262.69	271.00	279.09	287.98	175.47	166.24	168.36	185.77	210.24	232.77	250.28
	LDI Managed TE Summer							LDI Managed TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
Central Bronx	192.97	183.98	177.51	179.27	184.71	188.08	191.88	114.57	109.87	112.35	123.63	137.89	149.13	157.64
Grand Central	160.98	146.44	135.75	132.46	133.33	136.21	139.62	115.96	106.76	108.87	120.30	136.52	153.39	165.54
Sheepshead Bay	162.01	155.78	151.38	154.37	159.75	163.14	166.87	90.37	87.52	89.80	99.32	110.96	119.85	126.81
Wainwright	85.00	81.28	78.53	79.24	82.03	83.22	84.61	31.03	31.12	32.78	37.88	43.80	46.93	49.31
Yorkville	289.02	270.74	258.10	257.86	262.62	267.10	272.38	175.47	165.98	167.85	184.32	206.50	225.92	240.15
	LDI No TE Summer							LDI No TE Winter						
	2021	2025	2030	2035	2040	2045	2050	2021	2025	2030	2035	2040	2045	2050
Central Bronx	192.97	182.58	174.78	172.04	172.03	173.81	176.03	114.57	108.93	109.34	114.90	123.53	133.29	140.37
Grand Central	160.98	146.34	135.57	131.99	132.16	134.75	138.04	115.96	106.60	108.57	119.40	135.01	151.84	163.95
Sheepshead Bay	162.01	154.15	148.22	146.11	146.07	147.40	149.05	90.37	86.32	86.46	90.27	96.29	103.00	107.76
Wainwright	85.00	80.21	76.51	75.13	75.02	75.74	76.66	31.03	29.51	29.67	31.25	33.66	36.31	38.20
Yorkville	289.02	269.79	254.91	250.01	250.09	253.41	257.57	175.47	165.05	166.09	177.15	194.32	212.83	226.14

Endnotes

1 Please note that while the NYISO Gold Book includes its own assumptions for load growth from electric vehicles, the TEDI study relied on the CTR for transportation electrification assumptions for all the scenarios including the reference scenario.

2 In the Pathways Study, the end-use, energy efficiency and building electrification load growth are rolled into one value.

3 California Energy Commission. 2019. Joint IOU Electric Vehicle Load Research - 7th Report. https://efiling.energy.ca.gov/GetDocument.aspx?tn=228787-14&DocumentContentId=60075

4 https://www.sciencedirect.com/science/article/pii/S030142151930638X

5 https://www.mckinsey.com/business-functions/sustainability/our-insights/charging-electric-vehicle-fleets-how-to-seize-the-emerging-opportunity

6 The cost per mile of reconductoring or adding a new circuit was assumed to be $700,000.

7 CYME is the loadflow program used by National Grid.

8 This was based on the average length (700 feet) of segment-level upgrades provided by National Grid.

9 Some utilities offer incentive programs such as the EV Make Ready Infrastructure Program to upgrade or add infrastructure on the customer side of the meter.

10 In the Pathways Study, the end-use, energy efficiency and building electrification load growth are rolled into one value.

11 This factor is used to capture the fact that Con Edison capital cost estimates include two components— one for new equipment added and one for equipment installed that replaces existing equipment. The estimates that were developed in the PVL planning process includes only the first component. The second component is estimated using the 23.6 percent scale-up factor to arrive at the total capital costs for the project.

12 Level 2 chargers can be rated up to 19.2 kW, but most existing EV models can only accept charge up to a 7.6 kW (240 V/16-40 amps).

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