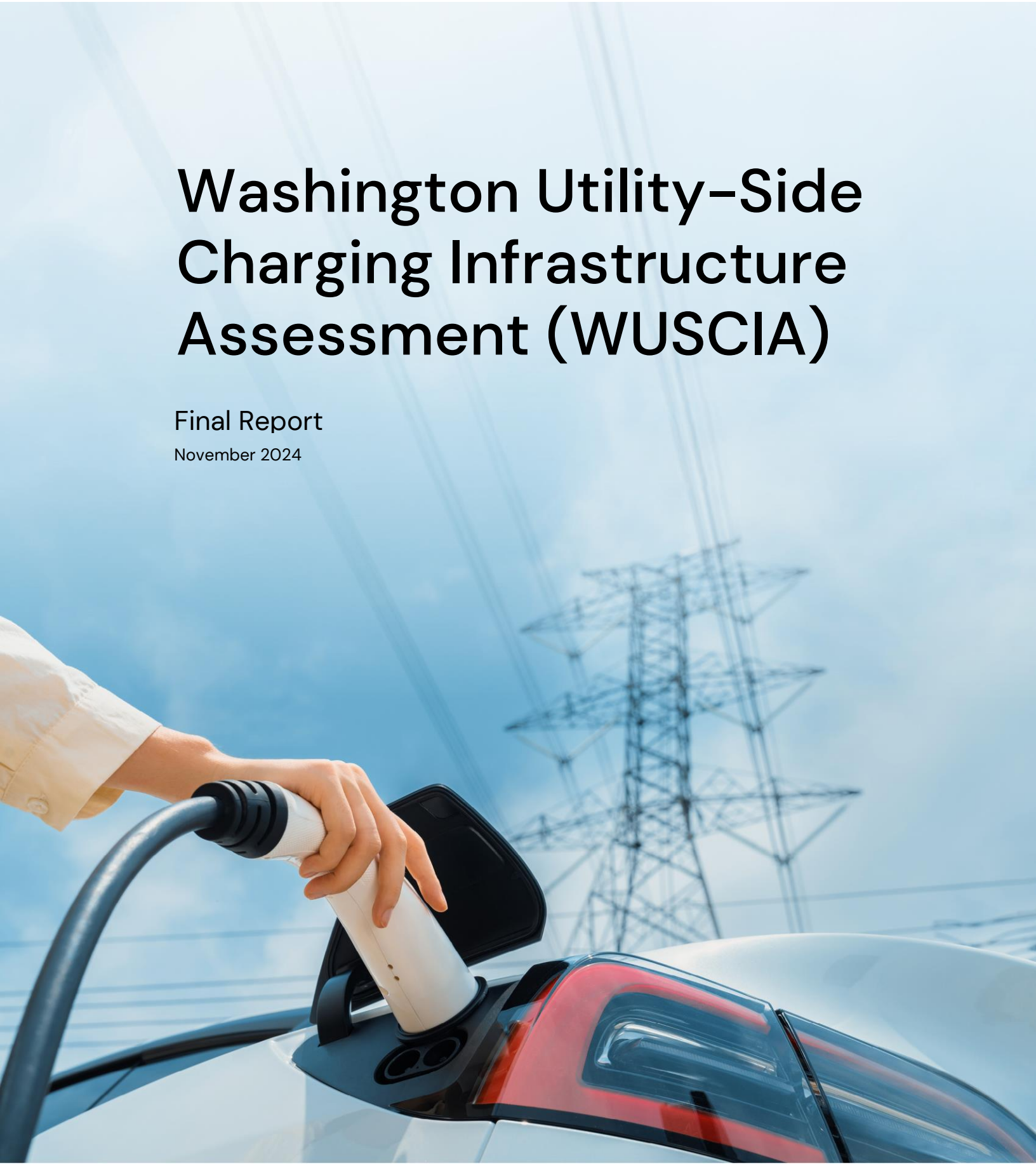
Washington Utility-Side Charging Infrastructure Assessment (WUSCIA)

Final Report

November 2024



Washington State Department of Commerce

ICF

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Executive Summary

The Washington Utility-Side Charging Infrastructure Assessment (WUSCIA) estimates utility-side costs needed to deliver power to the state's growing electric vehicle population, benchmarked to the landmark Transportation Electrification Strategy (TES). The TES was developed by the Interagency Electric Vehicle Coordinating Council (EV Council), published in February 2024, and includes recommended actions the state can take to ensure the benefits of driving electric vehicles (EVs), charging infrastructure, and market incentives are accessible and available to all people in Washington. This strategy is part of Washington's broader goal of reducing greenhouse gas (GHG) emissions and promoting sustainable energy solutions.

The Washington State Department of Commerce (Commerce) was appropriated funds in the 2024 supplemental transportation budget to commission this study based on the findings of the TES about costs of installation, maintenance, and operation of electrical distribution infrastructure on the utility's side of the meter to commercial customers installing electric vehicle supply equipment. Commerce was required to gather data from at least five electric utilities serving retail customers in the state, and submit findings and an explanation of how these findings will support implementation of the TES authorized under RCW 43.392.040 to the governor and appropriate legislative committees.

The transition to EVs will require significant upgrades to the electrical infrastructure, including the installation of new distribution circuits, transformers, and substations to handle the increased electricity loads. The assessment provides detailed cost projections for the planning, installation, and maintenance of the necessary infrastructure through 2035. The projected costs of transportation electrification can be used for prioritizing distribution planning, and identifying the cost savings due to managed charging and off-peak charging incentives. The assessment then examines the financial implications for various stakeholders including utilities, ratepayers, and electric vehicle service providers, and emphasizes the importance of equitable cost distribution to avoid disproportionate economic burdens on any single group. Understanding the total utility-side costs associated with reaching Washington's transportation electrification goals allows for strategic investment in grid infrastructure that minimizes unnecessary costs.

ICF worked closely with several utilities in the state of Washington to gather vital information about the distribution system to assess the financial and logistical impacts of increased electrification on the utility grid. Through this collaboration, ICF analyzed over 1,200 circuits, which provided more accurate projections for system upgrades and cost estimates for all utilities in the state. Below is a summary of the participating utilities and the number of circuits provided for the analysis.

Table ES1. Summary of utility data analyzed

Utility	Number of Circuits Analyzed
Mason County PUD No. 1	12
Avista	228
Kittitas PUD No.1	12
Seattle City Light	173
Puget Sound Energy	814
Total	1,239

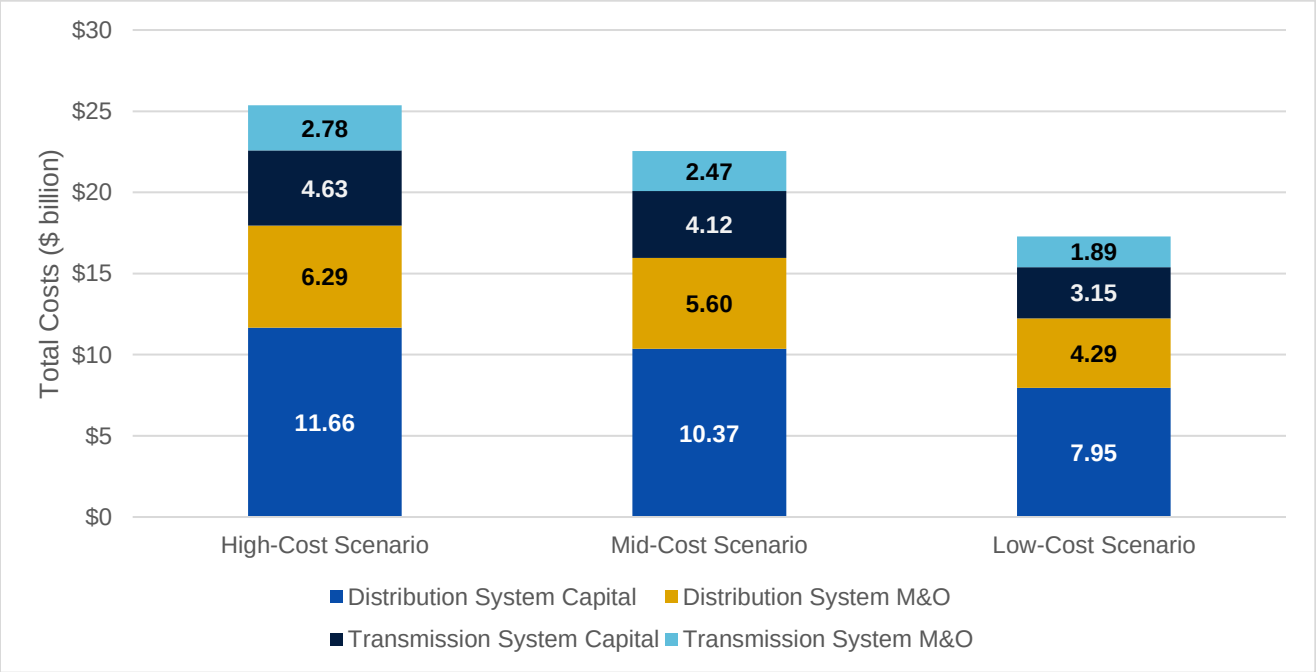
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1.1 Findings

The analysis finds that the capacity of the distribution system will likely need to increase by 4-7 gigawatts (GW) by 2035. The needed statewide utility infrastructure upgrades are estimated to cost between $17 billion and $25 billion, including $8 billion to $12 billion dedicated to building out the distribution system, considerably less than the alternative of gasoline and diesel energy costs, as indicated by the 2021 State Energy Strategy. The total costs include high-level transmission capital and operation and maintenance cost estimates. .

The analysis points to the importance of scaling up the initial utility efforts to manage charging to more evenly spread electricity needs across different times. This work is essential to lower overall costs, remove financial barriers to large-scale charging projects, and protect ratepayers who have less access to EVs.

Figure ES1. Statewide high-, mid-, and low-cost scenarios associated with utility-side infrastructure upgrades to support transportation electrification, maintenance and operation (M&O) included

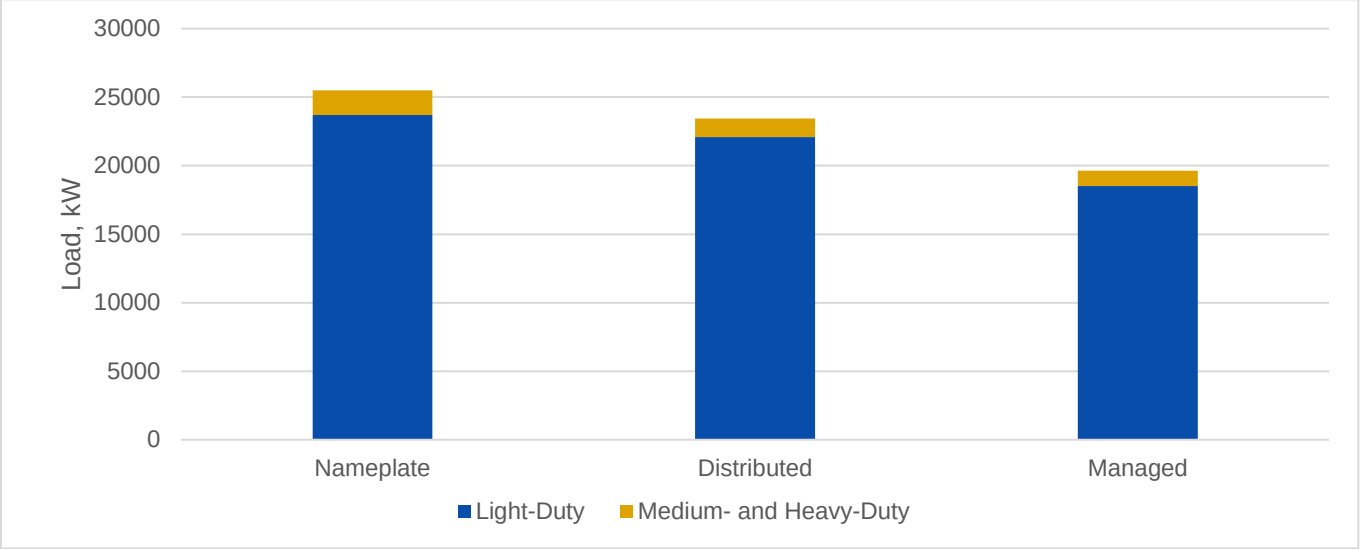


EV-related grid costs can be reduced by more than 30% through carefully planned managed charging.

With appropriate measures and reinforcement, the implementation of managed charging could save up to $8 billion dollars in infrastructure and operations. The project team recommends that both the state and utilities examine the full set of options for incentives, rate policies, actively managed charging and demand response programs to help mitigate the impacts of EV charging costs to utilities and ratepayers. Compared to the nameplate standard, defined as the maximum possible demand scenario, the distributed and managed scenarios in Figure ES2 demonstrate a smaller peak load. Peak load is used to determine what grid infrastructure is needed to meet the electricity demand. Reducing the peak load through programs and strategic distribution planning by utilities can save unnecessary and costly grid upgrades.

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Figure ES2. Sample peak loads under the nameplate standard, distributed scenario, and managed scenario



The report provides more detail on potential strategies to manage charging loads, such as shifting charging times to off-peak hours to reduce peak loads and strain on the grid. Part of these strategies include preparing for disproportionate strain on the grid from different vehicle classes. Larger vehicles will demand greater charging concentrated along corridors, while light duty vehicles will largely charge at home. These strategies will optimize the use of existing infrastructure.

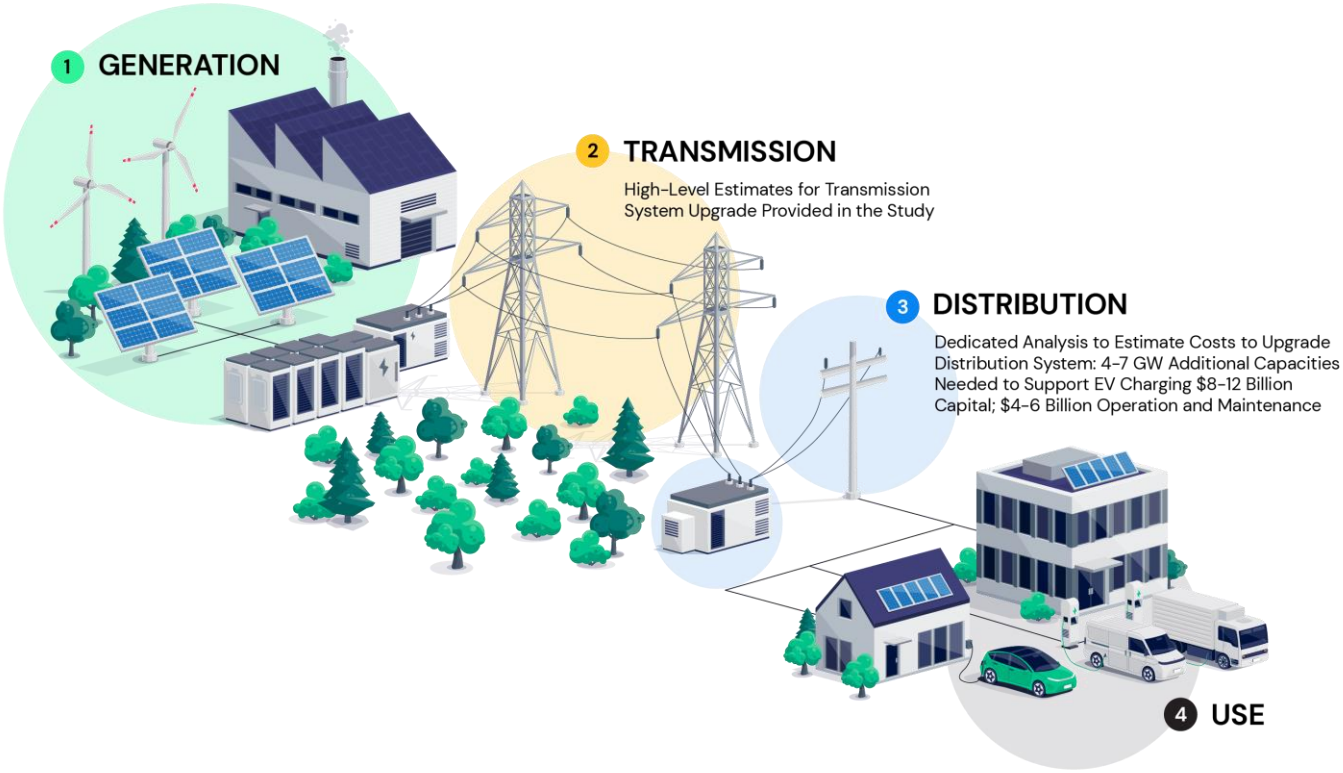
Utilities need to plan to prevent project backlogs that risk slowing the EV transition.

The state will need to identify who is coordinating planning work between utilities and fleets and ensure those efforts are funded. Additionally, utilities will need to carefully plan EV-required upgrade projects with general system planning upgrades that normally occur throughout the distribution planning process. Due to current limitations such as supply chain delays for required equipment, general system improvement projects are experiencing a longer timeline for completion, sometimes taking over a year to energize a new load on the system. Planning for the increased equipment required to support electrification will need to be included in the project planning process.

Upgrading utility infrastructure for electric vehicles will cost considerably less than gasoline and diesel alternatives. However, not all ratepayers have access to electric options. The state and utilities should structure costs to ensure those who are most able to shoulder costs and access benefits take on of the cost burden.

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Figure ES3. Overview of the cost analysis undertaken in this study



1.2 Methodology

The project team gathered data from utilities, state agencies, and industry reports to complete the analysis. By overlaying estimated charging electricity loads over utility grid data, the costs for needed circuit and transformer upgrades or expansions and corresponding maintenance were then identified.

Utility data: Participating utilities provided circuit and transformer data to understand the loading of their existing systems. Utilities also provided cost estimates for conductors, transformers, and substation equipment, which were used to estimate the cost of upgrades for each circuit.

Charging targets: To understand the effect of load on utilities, the project team used the charger estimates from the TES for 2035 as outlined in the Strong Electrification Policy scenario. This scenario includes both the state's requirement that 100% of new passenger vehicles and light-duty truck sales be electric by 2035, and larger state and federal incentives for zero emission vehicles (ZEVs) and charging infrastructure. This scenario also assumes considerably faster adoption of zero emission medium- and heavy-duty (MHD) trucks and buses based on federal incentives from the Inflation Reduction Act.

To use the TES results, the project team developed a specific methodology to distribute heavy-duty charger counts from the county level to the Census Block Group (CBG) level. Hourly charging loads were then estimated at each CBG using three charging cases – (1) nameplate standard, (2) distributed scenario, and (3) managed scenario - which each represent different ways utilities estimate the impacts of EV charging infrastructure.

Grid analysis: Electricity loads were then applied to the utility grid data to identify the overloaded circuits and transformers across the three case studies. This data was used to estimate the costs of upgrading this

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infrastructure for the participating utilities. Then, these costs were projected across the entire state to fill in the regions of the state the project team did not have access to utility data. Ultimately, the model used utility data covering 47% of the state's population, and cost projections to cover the remainder of the state.

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List of Definitions

ACC	Advanced Clean Cars
ACF	Advanced Clean Fleets
ACS	American Community Survey
CBG	Census Block Group
CCA	Climate Commitment Act
CETA	Clean Energy Transformation Act
Commerce	Washington State Department of Commerce
CO2e	Carbon Dioxide Equivalent
COUs	Consumer-Publicly Owned Utilities
DCFC	Direct Current Fast Charging
DER	Distributed Energy Resources
EIA	U.S. Energy Information Administration
EV	Electric Vehicle
EV Council	The Interagency Electric Vehicle Coordinating Council
EVSP	Electric Vehicle Service Providers
GHG	Greenhouse Gases
HD	Heavy-Duty
ICEV	Internal Combustion Engine Vehicle
IOU	Investor-Owned Utility
LD	Light-Duty
L2	Level 2 Charger
MD	Medium-Duty
MFH	Multi-Family Housing
MHD	Medium- and Heavy-Duty
MHDV	Medium- and Heavy-Duty Vehicle
MMT	Million Metric Tons
MW	Megawatt
MY	Model Year
NTD	National Transit Database
PUD	Public Utility District
TES	Transportation Electrification Strategy
TOU	Time-of-Use
TWh	Terawatt-Hour
UTC	Washington Utilities and Transportation Commission
VMT	Vehicle Miles Travelled
VPP	Virtual Power Plant
V2G	Vehicle-to-Grid
WAC	Washington Administrative Code
WUSCIA	Washington Utility-Side Charging Infrastructure Assessment
ZEV	Zero-Emission Vehicle

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Introduction

In the state of Washington, the transportation sector represents 39% of economy-wide greenhouse gas (GHG) emissions.[1] In an effort to reduce carbon emissions from the transportation sector, the state has taken multiple actionable steps, including adopting clean vehicle regulations by reference from California. These regulations are part of a strong set of policies that will help Washington reach 100% electric sales for passenger vehicles and light-duty (LD) trucks by model year (MY) 2035, while also accelerating the transition of medium- and heavy-duty vehicles (MHDV) to zero emission.[2] To fulfill Washington's clean transportation and climate goals, the Interagency Electric Vehicle Coordinating Council (EV Council)[3], jointly led by the Washington State Department of Commerce (Commerce) and the Washington State Department of Transportation (WSDOT), created a comprehensive scoping plan, the Transportation Electrification Strategy (TES), to facilitate the transition to ZEVs across the state. The Washington Utility-Side Charging Infrastructure Assessment (hereby referred to as WUSCIA) serves as a follow-up to the TES, providing a comprehensive utility-side cost evaluation of the charging infrastructure buildout necessary for achieving Washington's ZEV goals.

1.3 Transportation Electrification in Washington

The TES reflects Washington's strong commitment to reducing GHG emissions from transportation through aggressive policy actions. In recent years, Washington has passed several such regulations that either indirectly or directly impact the transportation sector. In 2019, Governor Jay Inslee signed into law the monumental Clean Energy Transformation Act (CETA), which mandates that the state's electricity supply be 100% GHG-neutral by 2030 and 100% free of GHG emissions by 2045. In 2020, the Washington State Legislature enacted new emissions limits to cut GHG emissions 45% below 1990 levels by 2030, 70% below 1990 levels by 2040, and 95% below 1990 levels with net zero emissions by 2050. In line with these economy-wide limits, the Legislature established the non-binding target of 100% electric sales of publicly owned and privately owned passenger and light duty vehicles (LDV) by model year (MY) 2030. This regulation established the EV Council, a formal interagency council, to coordinate the state's transportation electrification efforts. The EV Council ensures the state is leveraging state and federal resources to the best extent possible and makes zero emissions incentives, infrastructure, and opportunities available and accessible to all Washingtonians.

Multiple ZEV regulations have been adopted since then to reduce transportation-related emissions. Notably, the Advanced Clean Cars (ACC) I and II programs mandate automakers to incrementally increase the sales of ZEVs, including battery-electric, hydrogen fuel cell, and plug-in hybrids with a minimum all-electric range of 50 miles, beginning in MY 2025. The sale percentage is projected to increase from 8-9% in MY 2025 to 100% by MY 2035. ACC I and II also include a provision for environmental justice credits to incentivize automakers to offer lower-cost ZEVs across the state.[4] Similarly, the Advanced Clean Trucks (ACT) regulation was adopted

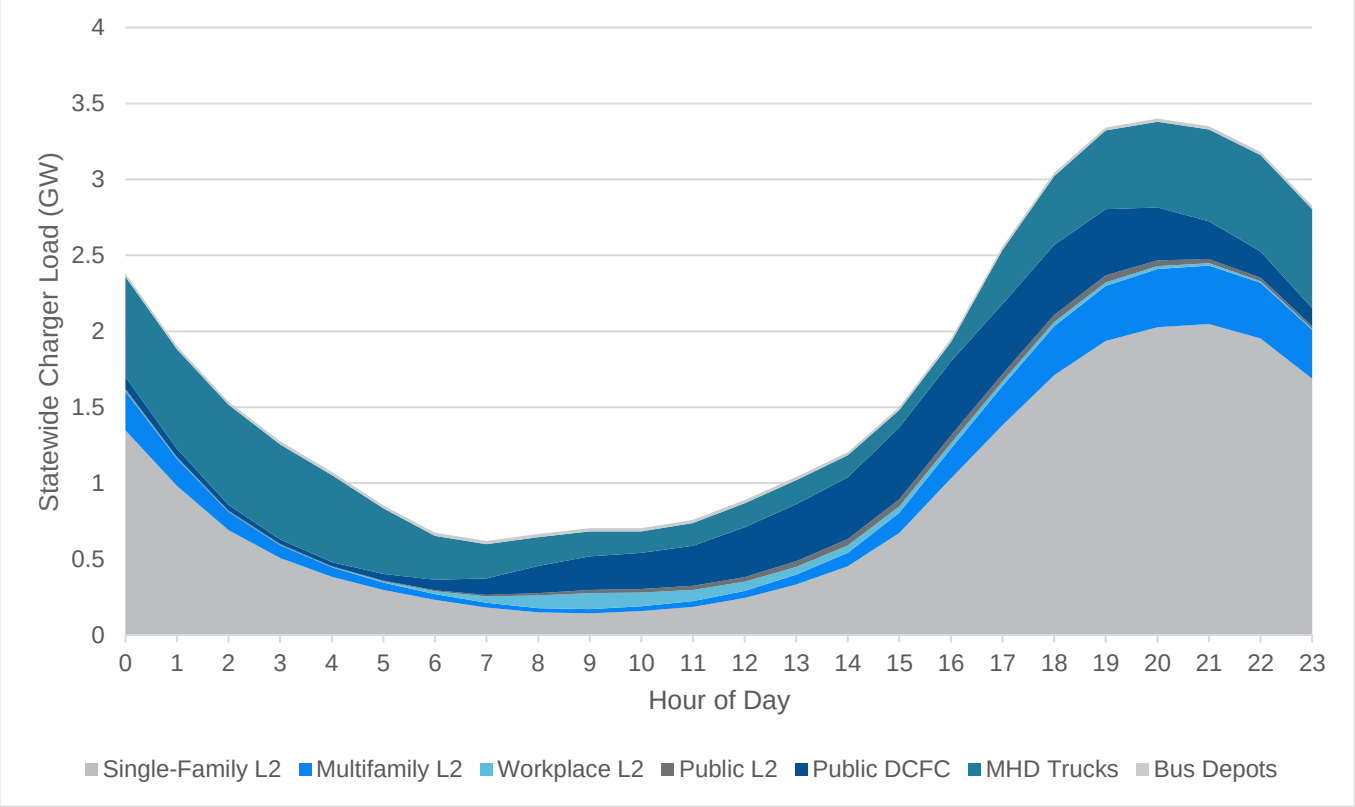
[1] Washington State Greenhouse Gas Emissions Inventory: 1990–2019. Available at: https://apps.ecology.wa.gov/publications/documents/2202054.pdf
[2] Washington State Department of Ecology, Clean vehicles. Available at: https://ecology.wa.gov/air-climate/reducing-greenhouse-gas-emissions/zev
[3] Washington State Department of Commerce, Electric Vehicle Coordinating Council (EVCC). Available at: https://www.commerce.wa.gov/growing-the-economy/energy/clean-transportation/ev-coordinating-council/
[4] Washington State Legislature, WAC 173-423-075: Zero-emission Vehicle Standards. Available at: https://app.leg.wa.gov/wac/default.aspx?cite=173-423-075

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in 2021, which requires manufacturers to produce and sell an increasing percentage of zero-emission MHD vehicles.[5] The ACT mandates 40-75% zero-emission MHDV sales, based on weight class, by MY 2035.

In 2024, the EV Council published the final TES for the period up to 2035. The TES provides a thorough evaluation of the state's infrastructure requirements, including electric vehicle supply equipment (EVSE), to accommodate the expected increase in ZEVs in the coming years. According to this evaluation, the state of Washington requires more than 3 million charging ports by 2035, generating an evening peak load of 3.4 GW under the Strong Electrification Policy scenario.[6] An overview of this projected load by 2035 is included in Figure 1. Given the substantial increase in demand from the accelerated deployment of EV charging infrastructure, significant upgrades to the electrical infrastructure are inevitable on both the customer and utility sides of the meter. These enhancements, crucial for maintaining grid capacity and reliability, will encompass a range of improvements, such as upgrading or adding new distribution circuits, replacing or augmenting transformers to handle higher loads, expanding or modernizing distribution substations for increased capacity, and implementing segment-level upgrades in areas heavily impacted by EV charging. In addition, they also involve upgrading distribution system components downstream from substations and main feeders, installing or enhancing voltage regulation systems for stable power supply, and strengthening transmission system components within each utility's territory.

Figure 1. Projected statewide EV load in 2035 under strong electrification policy scenario (TES)



[5] Washington Department of Ecology. Available at: https://ecology.wa.gov/blog/april-2023/electric-trucks-to-join-state-s-clean-transportati

[6] This scenario assumes that Washington enacts additional policy to support electrification such as higher incentives for ZEVs and EVSE, inclusion of the Advanced Clean Fleets (ACF) rule's adoption rates and education and outreach to encourage strong consumer interest in ZEVs.

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These necessary upgrades to support EV charging infrastructure will incur significant costs. The WUSCIA is designed to chart these financial requirements to successfully execute the TES. This encompasses the entire spectrum of costs related to planning, installing, maintaining, and operating the requisite utility infrastructure, to ensure efficient powering of all projected EV charging stations, ports, and connectors as outlined in the TES Strong Electrification Policy scenario, extending through 2035. This initiative is a critical step in managing the transition to an electrified transportation system in Washington, balancing cost-effectiveness with the ambitious objectives of the TES.

1.4 Washington Electric Utility Landscape

Washington has roughly 60 electric utilities in total. The Washington Utilities and Transportation Commission (UTC) regulates the state's three electric investor-owned utilities (IOUs): Avista Corporation, PacifiCorp, and Puget Sound Energy (PSE). The remaining utilities are consumer-publicly owned utilities (COUs) and include public utility districts (PUDs), municipal utilities, and electric cooperatives (Coop), each operating under unique governance models and an elected commission or city council. Figure 2 provides a map showing each utility's service area.

Figure 2. Map of utility service areas in Washington state[7]

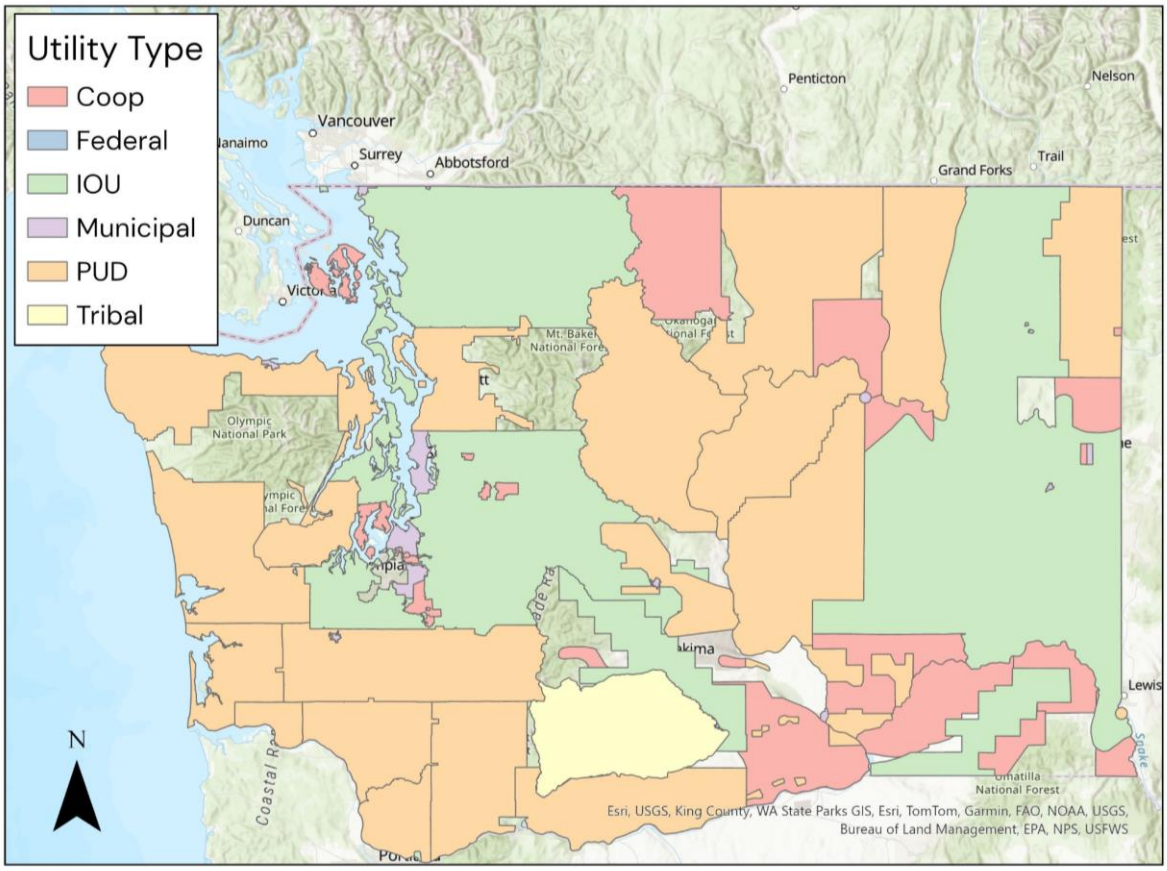
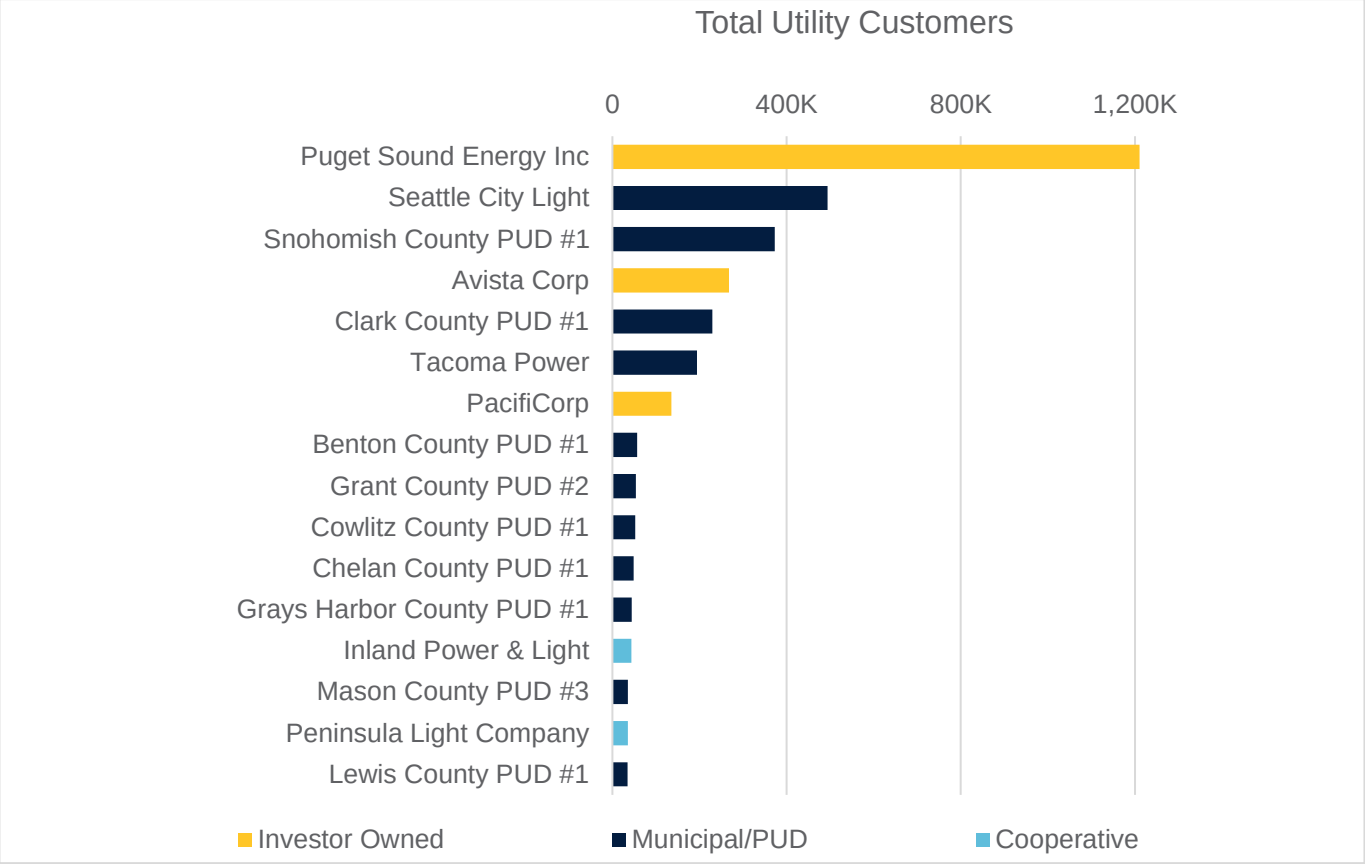


Figure *3* lists the total customers and the ownership type of Washington's sixteen largest electric utilities. The diverse profiles of utilities also lead to a variety of practices for grid planning, with multiple actors driving

[7] Washington State Department of Ecology, Electric Utility Service Areas. Available at: https://gis.ecology.wa.gov/portal/home/item.html?id=e62c6fcb7b674f15b8267fe9dc02f34f#

decision-making. This makes collective action on transportation electrification challenging. A major objective of WUSCIA is to enable these diverse stakeholders to work together. As such, several local utilities were engaged during their development to determine their diverse goals and interests, incorporate transportation electrification plans, and provide a platform for collective decision-making on EVSE-related grid upgrade planning in line with the TES.

Figure 3. Sixteen largest electric utilities in Washington by ownership type, and customers served[8]



1.5 Structure Overview

WUSCIA is a strategic initiative designed to provide a comprehensive estimation of the net present value costs associated with EVSE-related infrastructure on the utility side of the meter. It serves as a critical step in managing the transition to an electrified transportation system, balancing cost-effectiveness and diverse stakeholder interests with the ambitious objectives of the TES. The next section of this report describes the methodology used to conduct the net present cost estimation for EVSE-related grid upgrades. The following sections detail the local utility engagement process, key results and findings of the assessment, their implications for key stakeholders and the broader economy, and actionable recommendations for policymakers to facilitate utility-side infrastructure development in line with the TES and state climate goals.

[8] Northwest Clean Energy Atlas, Washington Electric Utilities Overview. Available at: https://www.nwceatlas.org/visualization/washington-electric-utilities-overview

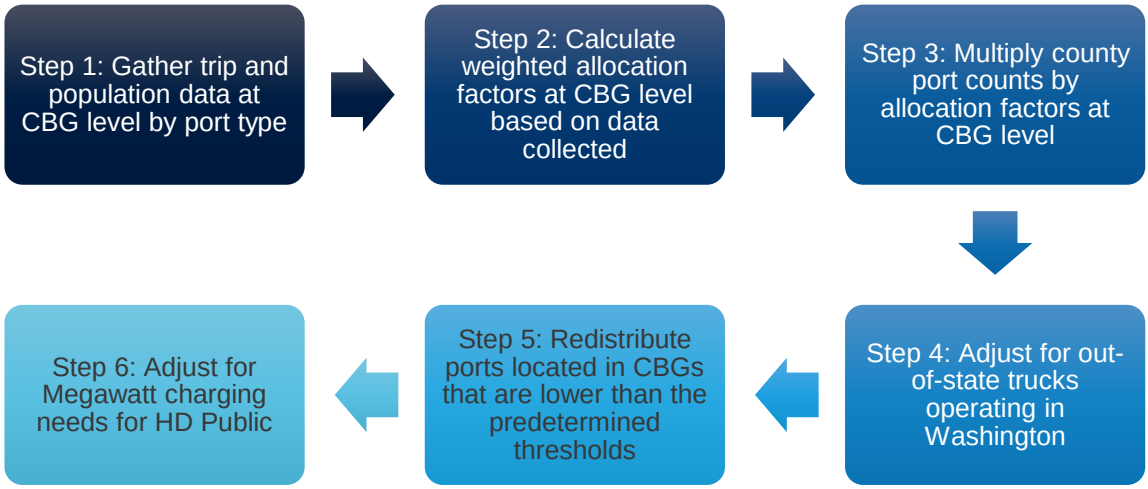
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Methodology

1.6 Refine TES EV Charging Results

This analysis utilized the results of the TES, which included projections of EV adoption in the state of Washington by 2035 and estimates of vehicle miles traveled (VMT) and the electrical load needed to power them across several different policy scenarios. At the direction of Commerce, the project team used the Strong Electrification Policy (#3) scenario[9] as a basis for this work in estimating the number of charging ports needed throughout the state. In order to understand the impacts of these vehicles on utilities at the most granular level, the project team needed to estimate the additional capacity needed at the smallest geographical level of analysis possible. For this study, Census Block Groups (CBG) were used since it is the smallest area in which trip data and population data are both available. The TES also used CBG as the unit of analysis for LD vehicles, so the estimates of LD EVSE port counts can be applied directly. However, the TES only produced estimates of MHD charging ports at the county level, and thus the project team downscaled them to the CBG level to allow the analysis to take place at the consistent geographic scale across all port types. This section describes the techniques used to downscale this data as well as other adjustments made to the TES MHD results. A summary of this process is described in Figure 4.

Figure 4. Procedure for distributing county-level EVSE port counts to the CBG level



First, the project team used a set of variables to determine the allocation factors of ports from each county that should be distributed to a given CBG. For each of the vehicle and charger type combinations, the variables shown in

[9] This scenario was seen as the most feasible and likely EV adoption scenario based on the state's current policy commitments. It considers the effects of Washington's implementation of California's Advanced Clean Cars II and Advanced Clean Fleet policies through its commitments as a Section 177 state, as well as proposed vehicle and infrastructure incentive policies. More details on this can be found in the final TES.

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Table *1* were used to calculate the allocation factor, which reflected the fraction of that EVSE ports which fell into each CBG.

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Table 1. Variables used to distribute county chargers down to CBG level

Vehicle Type	Charger Type	Input Data	Data Source	Weight
School Bus	Depot	School-aged population (5-17 yrs.)	US Census	100%
Transit Bus	Depot	Revenue-miles by transit agency	National Transit Database (NTD)	100%
		Locations of bus depots by transit agency	NTD	N/A[10]
		Buses in operation by bus depot	NTD	N/A[11]
Medium and Heavy Duty	Public	Commercial vehicle trip origins	Replica[12]	30%
		Commercial vehicle trips over 50 miles	Replica	20%
		Number of truck parking spaces in truck stops	Washington Department of Commerce	50%
	Depot	Commercial vehicle trip origins	Replica	50%
		Area zoned as industrial or warehousing	Washington State Parcels Project[13] (2023)	50%

One of the limitations for the assumptions used for transit buses is that it assumes that all charging for buses will happen at depots – and not along routes. While some transit agencies have expressed interest in expanding on-route charging, there is currently a lack of commitment from the industry toward this technology as well as notably higher infrastructure costs compared with depot charging. Thus, all transit charging was assumed to take place at the depot. This is a fair assumption since a depot is usually the most cost-effective place to install chargers for the agency and in many cases, charging at a depot is used directly by the utility which oversees that depot for grid planning purposes.

Given there is not a dataset which covers school bus depots for all school districts in Washington, school bus depots are assumed to be reasonably distributed along with student populations. An example to calculate the allocation factor for school bus depot charging ports is given in Equation 1. When calculating the allocation factor of charging ports, the school-aged population in any given CBG is divided by the total school aged population of that county.

Equation 1. Example of the allocation factor calculations for the school bus depot ports

$$School\ Bus\ Depot\ Allocation\ Factor_{CBG} = \frac{School\ Aged\ Population_{CBG}}{School\ Aged\ Population_{County}}$$

[10] Used to identify which CBGs to locate each transit agency's revenue miles in.
[11] Used to allocate revenue miles between depot locations for agencies with multiple depots.
[12] Replica data lists every trip taken by commercial trucks which either starts or ends in Washington in Spring 2023 on a typical Thursday. It includes the census block group in which each trip started and ended, trip purpose, trip length and the trip start and end times.
[13] Washington State Geospatial Open Data Portal. Available at: https://geo.wa.gov/datasets/a0ddbd4e0e2141b3841a6a42ff5aff46

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For the public charger data, the locations of existing truck stops were assigned with a highest weight because those are the most likely sites for future MHD public chargers. These places already show high demand for truck traffic and often have amenities, which would serve drivers that are staying for extended periods of time while charging. Truck trips over 50 miles were weighted higher because they are more likely to require public charging. Given there are more data sources used for this EVSE category, the formula to calculate the weighing factor, as shown in Equation 2 is more complicated than that for school bus depot.

Equation 2. Example of the allocation factor calculations for the HD public charging ports

$$\begin{aligned} &HD\ Public\ Charger\ Allocation\ Factor_{CBG} \\ &= 30\% \times \frac{Number\ of\ HD\ Trips\ Originated_{CBG}}{Number\ of\ HD\ Trips\ Originated_{County}} + 20\% \\ &\times \frac{Number\ of\ HD\ Long\ Distance\ Trips\ Originated_{CBG}}{Number\ of\ HD\ Long\ Distance\ Trips\ Originated_{County}} + 50\% \\ &\times \frac{Number\ of\ HD\ Truck\ Parking\ Spaces_{CBG}}{Number\ of\ HD\ Truck\ Parking\ Spaces_{County}} \end{aligned}$$

For MHD depot charging, trips over 50 miles were no longer considered because depots can be home to an assortment of different vocation types with more frequent and shorter trips. However, areas within a given CBG zoned as industrial or warehousing were accounted for, since these are the types of locations which already serve as truck depots and are anticipated to host depot chargers in the future.

After calculating the allocation factors for each CBG by EVSE port and vehicle type, county level charging port data to the CBG level by multiplying the county total by that CBG's factor. An example of this for the HD Public chargers is shown below in Equation 3.

Equation 3. Example of the allocation of ports from the county to CBG level for HD public ports

$$HD\ Public\ Port_{CBG} = HD\ Public\ Charger\ Allocation\ Factor_{CBG} \times HD\ Public\ Port_{County}$$

The project team then adjusted the charger counts for trucks operating in Washington that are registered out of state. Note that the EVSE projections from the TES did not account for the charging demand of trucks not registered in Washington. The TES, however, has determined that out-of-state registration is roughly 18% to 30% for MD trucks, and 30% to 50% for HD trucks.[14] These factors were used to scale up the electricity demand to reflect charging demands from out-of-state trucks. This adjustment is necessary because it assesses the energy demand more accurately as trucks operated in the state, are likely to charge. The project team also confirmed the out-of-state fraction by cross-referencing it with the trip fractions from out-of-state trucks in the Replica data to ensure that the applied scaling factor is appropriate.

While trip- and population-based data serve as a reasonable proxy to distribute chargers from county to CBG levels, this methodology could lead to some unreasonably small numbers of chargers in certain CBGs. For instance, from a profit-generating perspective, it is very unlikely to see one public DCFC port by itself in one CBG. As a reference, currently in the state of Washington, one public DCFC charging station has four ports on average.[15] Therefore, the project team applied a threshold to regroup chargers from CBGs with small fractions.

[14] RMI analysis of FHWA data suggests that in Washington, the percentage of total state highway miles driven by vehicles registered outside the state is approximately 18% for MD trucks and potentially as high as 50% for HD trucks.
[15] Average calculated based on the U.S. Department of Energy Alternative Fuels Data Center Station Locator. Available at: https://afdc.energy.gov/stations#/find/nearest

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In the case of depot chargers, any CBG with less than one port for a given type was reallocated into the pool of total chargers. For public chargers, any CBG with fewer than four chargers were reallocated. This difference is explained by the fact that one business might have a single charger in a given area. Still, it is not expected that MHD charger installations be made with only one or two chargers due to the high cost of electrical and charging infrastructure required to install them. Then, the chargers in the pool were reallocated to CBGs based on the proportion of chargers in the county that they already received. This follows the principle that the relative proportion should not change but that these reallocated chargers are more likely to go to places with very high demand (dozens of chargers) than those which are projected to only have one or two chargers.

Lastly, the project team apportioned some of the charging demand from long-haul trucks to megawatt (MW) charging stations. Long-haul trucking is expected to rely upon these faster charging options to make interstate travel possible, which typically use a larger draw than 350kW. The TES assumed that public charging power caps out at 350 kW, which was determined to be too small for this analysis. For instance, according to long-haul tractors telematics data, 25% of trips are slip-seat operations, which means the truck is driven for more than 700 miles or 16 hours without stopping for a break of 4 hours or longer.[16] In such cases, high-power MW public charging will be necessary. Per communication with HD charging providers, the project team learned that these providers intend to exclusively use MW-charging compatible chargers at their larger charger depots since these stations provide the highest hourly revenue per station. This allows the providers to recoup their upfront investment in charger installation faster and make them a destination for electric truckers in the future. Knowing this, every CBG with 20 or more HD public chargers was upgraded to host MW chargers. This leads to a higher peak demand than what was originally estimated in the TES, but this would be necessary for long-haul fleet applications given this new data. The results of this distribution are illustrated in Figure 5. Note that not all CBGs are expected to have MHD chargers.

1.7 EV Charging Peak Loads

Having determined the number of chargers at each CBG in Washington, the project team estimated the amount of additional capacity in the distribution system needed in each CBG. In this study, peak hourly loads imposed by these chargers were used on the grid as a proxy for capacities required to support EV charging activities. These loads were then fed into the electrical simulation software (e.g., Windmil, Synergi, and CYME) that models and analyzes power distribution systems to estimate the excess capacities that need to be built out by utilities. The project team has defined three different cases for estimating the peak loads of these chargers across the day, as summarized in Table 2 below.

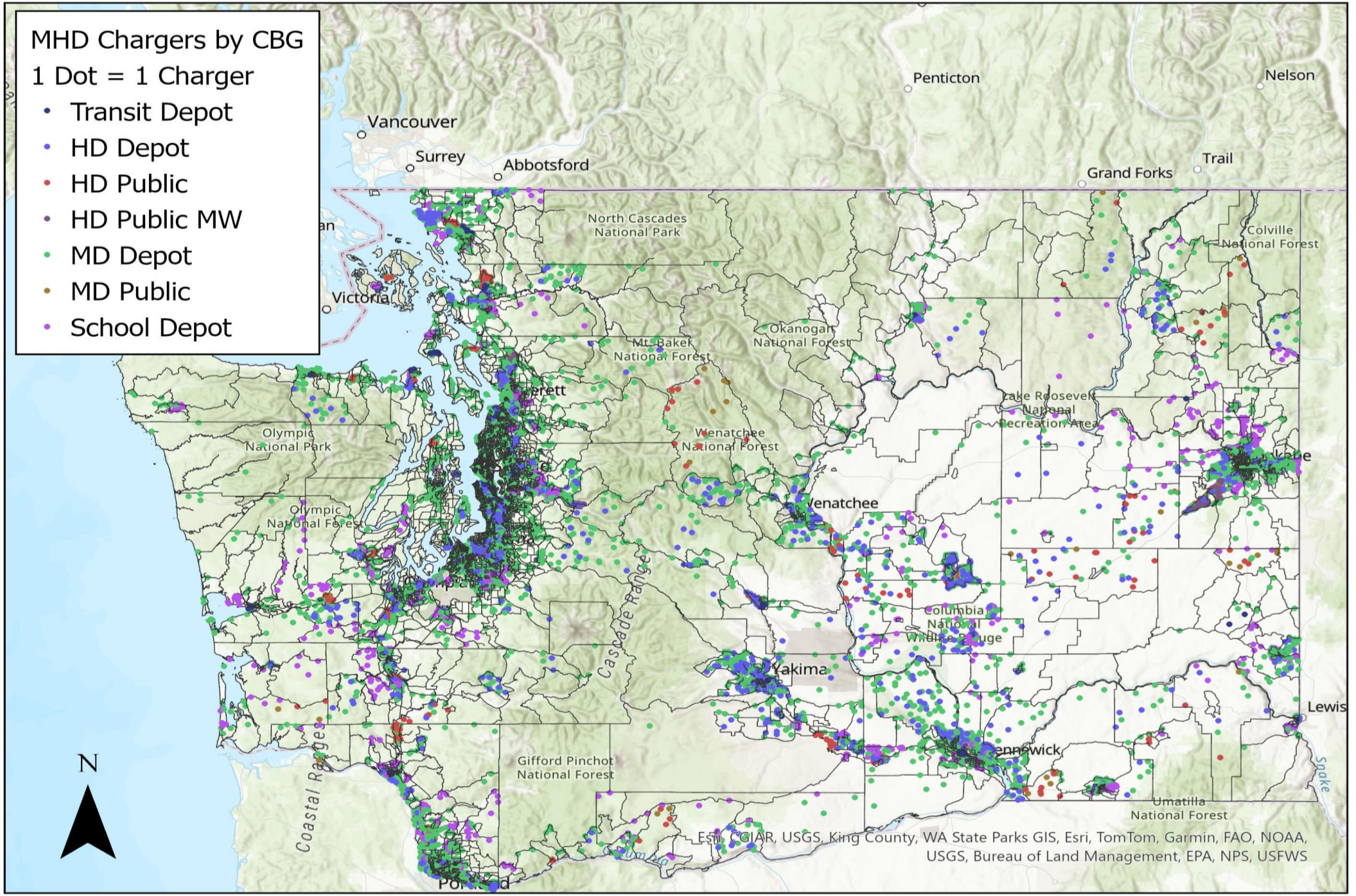
Table 2. Overview of charging demand cases

Scenario #	Charging Case	Charging Characteristics
1	Nameplate (Maximum Demand)	Assume all chargers' peaks are concurrent.
2	Distributed	Chargers operate at a fraction of peak load determined by usage pattern
3	Managed	Distributed curve is shifted away from peak hours to late-night lull

[16] Mishra P, Miller E, Santhanagopalan S, Bennion K, Meintz A. A Framework to Analyze the Requirements of a Multiport Megawatt-Level Charging Station for Heavy-Duty Electric Vehicles. Energies. 2022; 15(10):3788. https://doi.org/10.3390/en15103788

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Figure 5. Medium and heavy-duty chargers by type after distribution to the CBG level



Nameplate Standard

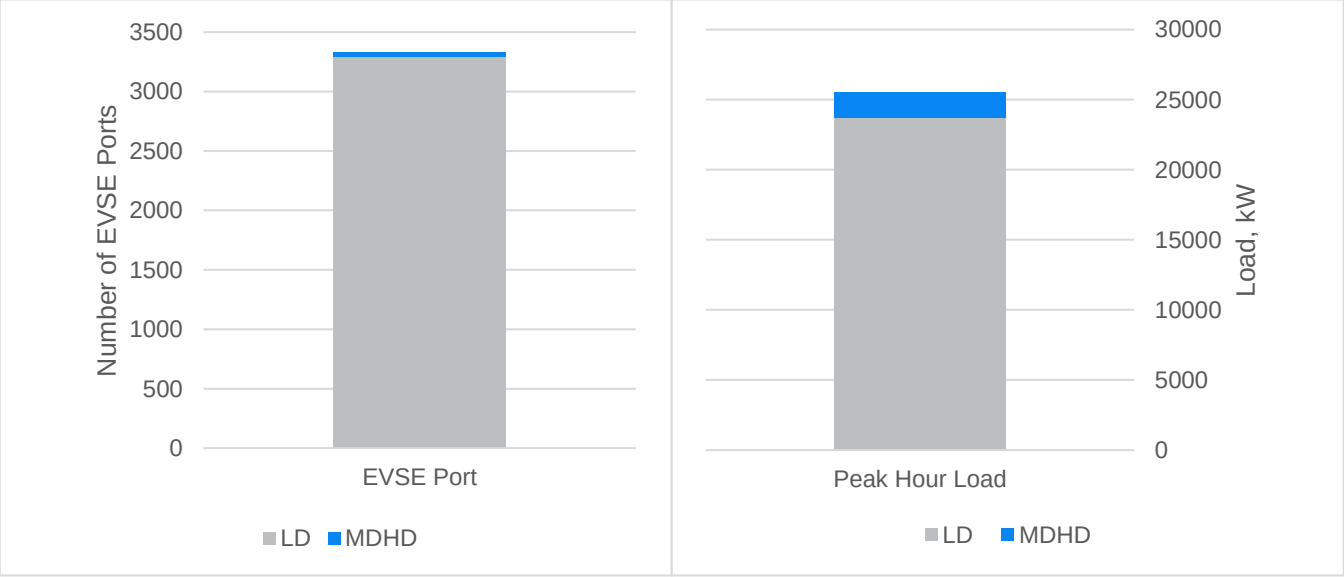
For the nameplate standard, the number of chargers by type was allocated to each of the CBGs, and the load was determined by assuming that all charging ports peak at the same time. This assumption is very conservative and certainly unrealistic, but it can serve as a reference to highlight why nameplate standard should not be used for future EV demand planning. The nameplate standard should also demonstrate the benefits of considering real-world vehicle travel patterns and implementing managed charging strategies. Consequently, this standard will yield an extremely high-cost estimate because it will require the largest scale infrastructure upgrade. The method to calculate the peak load for each block group in this case study is demonstrated in Equation 4 where PortCount is the number of ports present at a CBG given an EVSE type and PortPower is the nameplate capacity of the port type.

Equation 4. Example of the hourly load calculation for their nameplate standard

$$Load_{Peak,CBG} = \sum_{port\ type} PortCount_{CBG,port\ type} \cdot PortPower_{port\ type}$$

Figure 6 illustrates an example of how peak hour load was calculated under the nameplate standard case in one CBG.

Figure 6. An example of EVSE peak load under the nameplate standard case



Distributed Scenario

For the distributed scenario, a system hourly load curve was used to calculate the probability of whether a certain type of charger would be online during a specific time of the day. The hourly load curves for this study came from the statewide time-of-day load estimates published in the TES under the Strong Electrification Policy scenario. Given that the TES results aggregated all MHD trucks within a single load profile, the project team supplemented this data with California's Electric Vehicle Charging Infrastructure Assessment[17] results to

[17] California Energy Commission, Second Assembly Bill (AB) 2127 Electric Vehicle Charging Infrastructure Assessment: Assessing Charging Needs to Support Zero-Emission Vehicles in 2030 and 2035. Available at: https://www.energy.ca.gov/publications/2023/second-assembly-bill-ab-2127-electric-vehicle-charging-infrastructure-assessment

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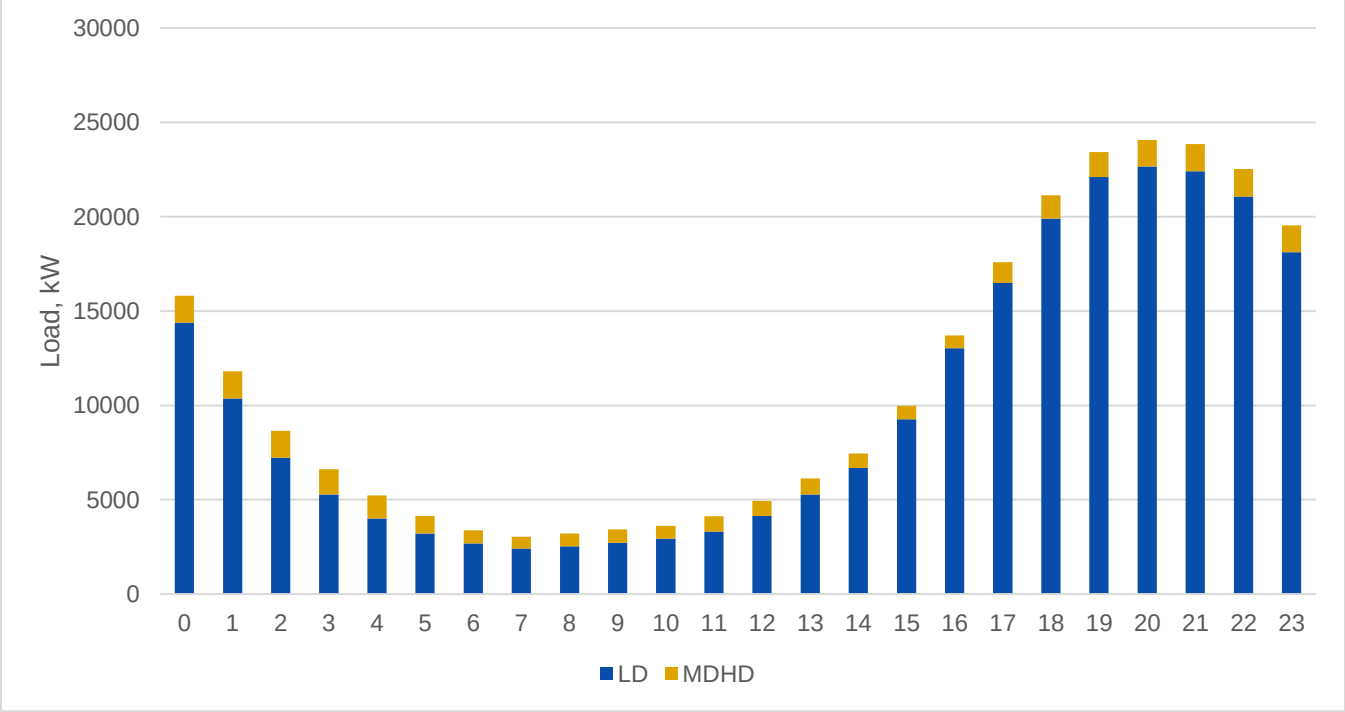
estimate the hourly occupancy probabilities for MHD public charging. Realistically, the peaks for residential, commercial, and fleet charging will not occur at the same time. This scenario is more likely to occur compared to the nameplate standard because it reflects the time-of-day load estimates based on the TES modeled results and will correspond to the statewide mid-cost scenario. To calculate the load for this scenario, as shown in Equation 5, the project team used a similar method to the nameplate standard but added the utilization factor based on the occupancy probabilities by charger type.

Equation 5. Example of the hourly load calculation for the distributed scenario

$$Load_{hourly,CBG} = \sum_{port\ type} PortCount_{CBG,port\ type} \cdot PortPower_{port\ type} \cdot Probability_{port\ type,hour}$$

In Equation 5, PortCount and PortPower have the same definition as in Equation 4, and the Probability at every hour represents the charger occupancy probability between zero and one, the latter being the nameplate value. Moreover, the hourly distribution factor is different for each charger type. For example, the peak load for single-family house L2 occurs in the evening, while that for workplace L2 occurs during the daytime. An example of the results from this scenario is shown in Figure 7.

Figure 7. An example of EV charger load under the distributed scenario



Managed Scenario

The managed scenario assumes that the state and utilities will implement policies and programs to incentivize off-peak charging, encouraging drivers to charge throughout the day to minimize the size of the evening charging peak. Examples of these policies include free workplace charging, time-of-use (TOU) EV utility rates, smart delayed charging, and direct utility control. With appropriate control measures, the charging behavior patterns can be shifted from peak hours to the utility infrastructure valleys, reducing the maximum peak value

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observed in the distributed scenario. The managed scenario will correspond to the lowest cost estimates across all three cases.

Managing loads to reduce peaks has been researched extensively in the past. A recent study, published in the Journal of Energy Storage, found that implementing smart charging in passenger vehicles can reduce peak loads by 34%.[18] Another study, published in the Renewable and Sustainable Energy Reviews, claimed that altruistic charging, which allows for charge management at ports and considers that vehicles don't need to fully charge before starting their next trip, can also lower the peak by about 21%.[19] It is also likely for managed charging to occur in the MHD sector, which may require fleets to adjust their conventional operations. For instance, in the California AB2127 assessment[20], a managed demand scenario of MHD vehicles was modeled by shifting loads from peak hours to the time period that aligns with renewable energy generation.

Table 3. Peak hours for EV charging by type and redistribute periods

Port Type	Peak Hours	Redistribute periods
Single Family L2	5 PM – 11 PM	12 AM – 5 AM
Multi Family L2	5 PM – 11 PM	12 AM – 5 AM
Workplace L2	8 AM – 11 PM	9 AM – 5 PM
Public L2	2 PM – 7 PM	9 AM – 5 PM
Public DCFC	No change	No change
MHD Depot	5 PM – 11 PM	12 AM – 5 AM
MHD Public	11 AM – 5 PM	12 AM – 5 AM
School buses	7 PM – 11 PM	12 AM – 4 AM and 9 AM – 2 PM

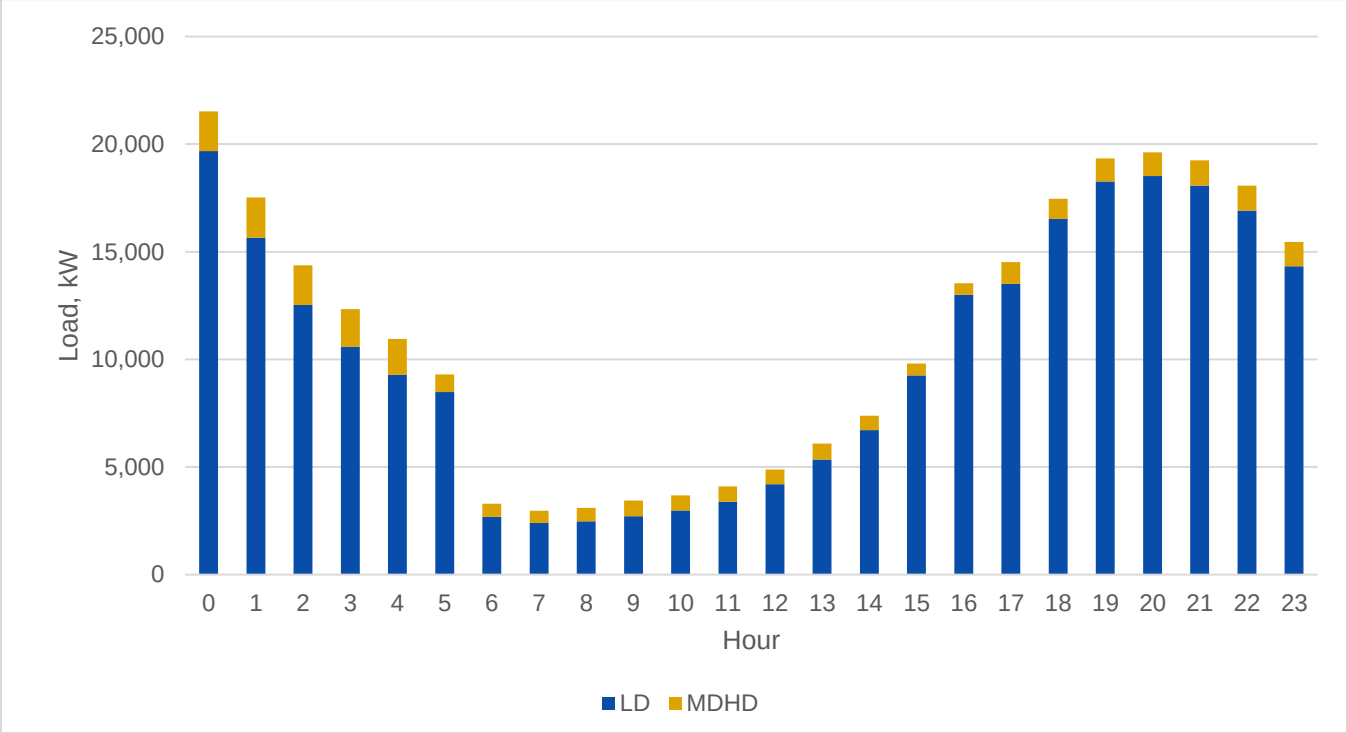
In designing the managed scenario for this study, the project team considered that incentives and smart charging management could operate throughout the day and have the potential to reduce 20% from each charger's peak. The loads were then redistributed across the infrastructure's lower demand periods. Table 3 demonstrates the peak hours observed from the distributed scenario and the hours that peak load was redistributed under the managed scenario by different chargers and vehicle types. LD DCFC loads are often unpredictable and associated with specific needs that are difficult to alter through incentives. For instance, the time to charge for ride-hailing service drivers is greatly limited by breaks between trips and customer-finding algorithms. Charging breaks during long-distance road trips will also be difficult to mitigate. Therefore, no adjustment was applied to this port type. For MHD Public charging, knowing the vehicle schedule beforehand could reduce demand for public charging during the day.

To distribute the load, this scenario uses the same equation as for the distributed scenario (Equation 5), with the utilization factor adjusted per the redistribution periods shown above. This results in a load curve that is higher in the early morning when system wide electrical loads are lowest and is lower during peak hours. An example of this load curve is shown in Figure 8.

[18] Giuseppe Rotondo et al." Evaluating hourly charging profiles for different electric vehicles and charging strategies," *Journal of Energy Storage*, Volume 95, 2024, 112388, ISSN 2352-152X, https://doi.org/10.1016/j.est.2024.112388.
[19] B. Williams et al. "Driving change: Electric vehicle charging behavior and peak loading," *Renewable and Sustainable Energy Reviews*, Volume 189, Part A, 2024, 113953, ISSN 1364-0321, https://doi.org/10.1016/j.rser.2023.113953.
[20] https://www.energy.ca.gov/publications/2023/second-assembly-bill-ab-2127-electric-vehicle-charging-infrastructure-assessment

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Figure 8. An example of EV charger load under the managed scenario



Peak Load Comparison

As noted earlier, the actual peak loads will differ across each CBG due to a different combination of ports, since each EVSE type has its own unique profile. To demonstrate the impact of distributed and managed scenarios under various circumstances, the project team selected a few example CBGs with distinct charger type combination profiles, as shown in Figure 9:

- **R+C+I**: Urban CBG that shows charge type diversification, mixing both public and depot charging for LD and MHD.
- **R+C**: Suburban CBG with moderate MHD traffic and a significant presence of single-family housing (SFH), and multi-family housing (MFH) L2 chargers.
- **R**: Suburban CBG that has substantial SFH L2 and MFH L2 chargers.
- **I+Re+R**: A combination of industrial zones that shows a significant presence of HD Public chargers and retail areas that shows some MD Public charger presence, with some residential housing around.
- **TI**: CBG that hosts a major truck stop, surrounded by industrial zones.
- **TP**: CBG that hosts a major transit agency depot.

The peak loads for distributed and managed scenarios were calculated as fractions of those under the nameplate standard for each corresponding CBG. As shown in Figure 10, CBGs with less variety of chargers show a small reduction from the nameplate load, while the impact of distributed and managed scenarios is more significant for CBGs with a more diverse combination of charger types. More details can be found in Appendix A: Peak Load Comparison by CBGs.

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Figure 9. Charger presence in different CBG profiles. R: Residential, C: Commercial, I: Industrial, Re: Retail, TI: Truck and industrial, TP: Transit passengers

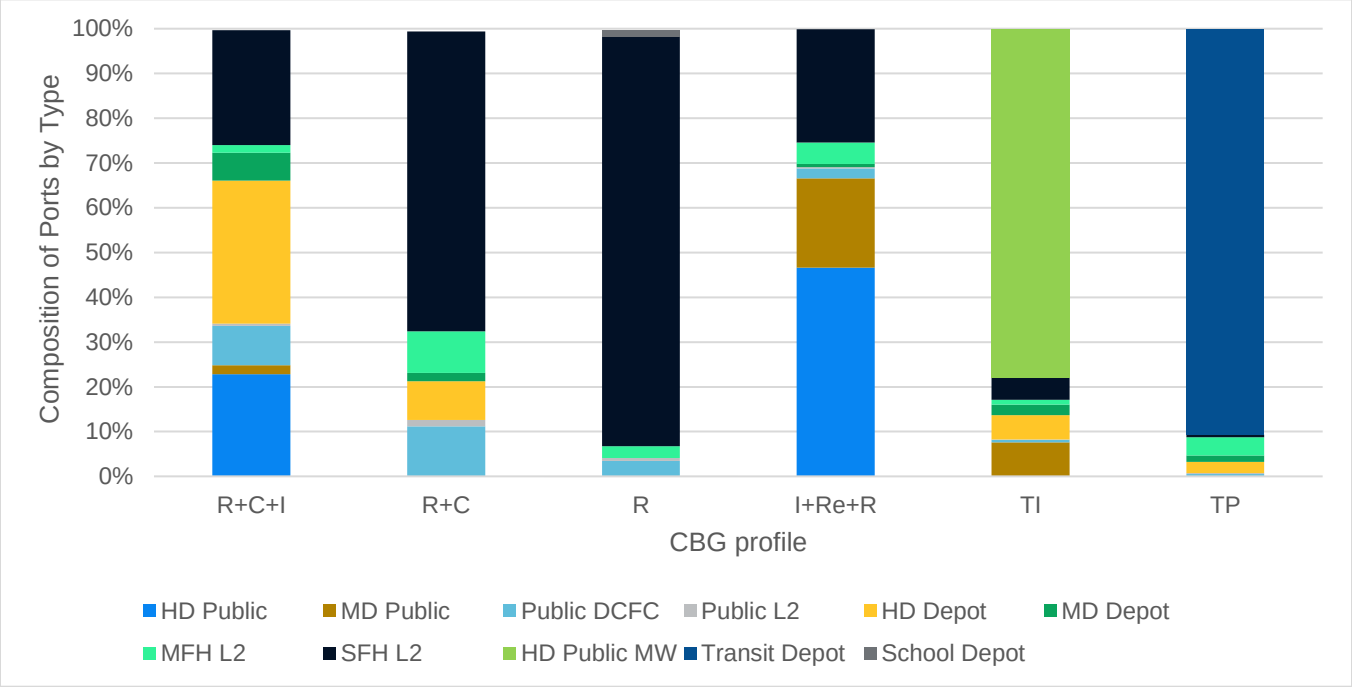
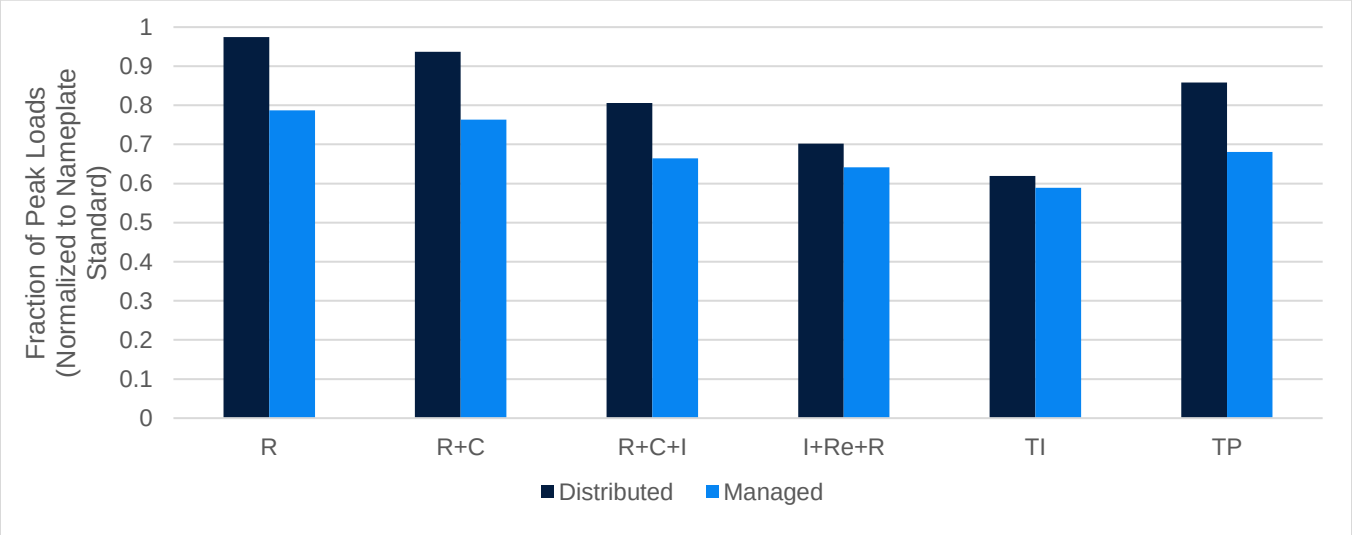


Figure 10. Fractions of peak loads under the distributed and managed scenarios as compared to the nameplate standard in various CBGs



Utility Data Gathering

To understand utility impacts and develop load allocation methodology, the project team worked with utilities in Washington to gather data about the distribution system. System models, equipment costs, peak loading data, engineering thresholds were collected to identify underloading or overloading, and geospatial data was collected to understand the impact of EV charging load on the electric distribution system. A data request guide was submitted (see

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Appendix B: Data Request Guide) to utilities to initiate data collection. The data request guide was designed to offer guidance to utilities for what data was required/requested for the study and what format would be appropriate for submission. Highlights of the data request guide and its relation to the project include:

- Cost data for equipment and devices required for grid reinforcement was collected from participating utilities and averaged to provide an estimate of costs applied to the anticipated system upgrades.
- Asset and load data such as circuit, substation transformer, and distribution transformers collected is required to estimate the amount of headroom available to add additional load to the system and determine when the load will exceed the equipment ratings and require upgrade.
- GIS asset and locational data is required to identify where within the census blocks the load should be allocated.
- Utility design criteria that determines equipment loading thresholds was used to identify limits for grid devices and assets and determine when grid reinforcement is necessary.
- NDAs or any other privacy concerns have been addressed during collaboration with participating utilities to ensure utilities have the freedom to share as much information as possible to enhance the study.

To facilitate this process, the project team also met with several utilities and discussed the project goals and parameters to encourage participation and feedback. Through this engagement, the project team included several utility models in the system analysis from utilities ranging in size from 9,000 to over a million customer meters. As shown in Table 4, the project team analyzed over a thousand circuits spanning several hundred miles across Washington through utility participation, utilizing a comprehensive source of data from which to draw.

Table 4. Summary of utility data analyzed

Utility	Number of Circuits Analyzed	Software
Mason County PUD No. 1	12	Windmill
Avista	228	Synergi
Kittitas PUD No.1	12	Windmill
Seattle City Light	173	CYME
Puget Sound Energy	814	Synergi

Load and Capacity Analysis

Once utility model data was received, transformers were extracted from the model and assigned to CBGs to create a spatial awareness between utility circuits and CBGs. The EV peak load at the CBG level was then assigned to designated utility transformers in the same CBG. For a CBG with multiple transformers, the load was distributed based on individual transformer capacities, as shown in

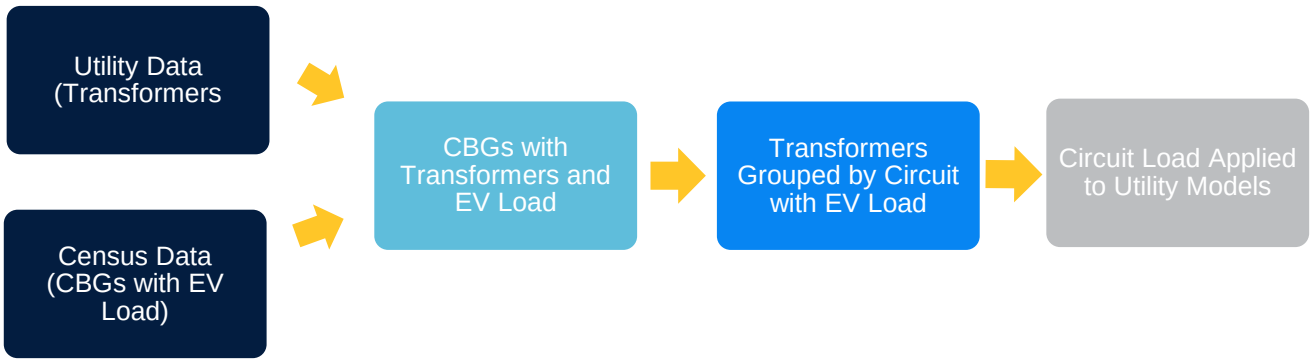
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Equation *6* . The loads by transformers were collected and then grouped by circuits to calculate the total load added to a feeder circuit. Figure 11 illustrates the load calculation methodology.

Equation 6: Example of the load assignment to individual transformer

$$Load_{Transformer,i} = \frac{Capacity_{Transformer,i}}{\sum_{CBG} Capacity_{Transformer}} \cdot EV\ Load_{CBG}$$

Figure 11. Process for using utility models to quantify EV adoption impact



Once the per-circuit loads were identified, they were added to the system models supplied by participating utilities. The project team extracted circuit level loading data for approximately 1,200 circuits in the state and added additional EV load to these circuits. Depending on which software the original utility model used, the project team utilized either Windmil, Synergi, or CYME analysis software to allocate the additional load and run load flow studies, first identifying overloaded conductor. Figure 12 shows examples of a model output under normal loading conditions (left) and after additional scenario load is added (right).

Figure 12. An example of load flow model under normal loading (left) vs. overloaded conductor requiring reinforcement highlighted in red (right)



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Utilizing the substation transformer and circuit loading limits provided by the participating utilities, the project team aggregated a standard circuit loading limit and identified circuits that exceeded that limit when additional charging loads were added. For those overloaded circuits, the loads that exceeded their existing capacities were aggregated to calculate the total number of new circuits and substation transformers needed in each charging case. The loading limitations were calculated by identifying a typical substation transformer size and a typical number of circuits that a new transformer would serve based on the supplied utility models and standard engineering practices. The circuit limitation was calculated by dividing the transformer capacity by the typical number of circuits. Below is a table summarizing the loading limits of circuits used to determine new circuits required to serve the additional scenario load.

Table 5. Circuit loading limits

Circuit voltage (kV)	Transformer size (MVA)	Number of circuits	Circuit limitation (loading in MVA)
26.4	75	5	15
12	25	4	6.25
13.8	20	2	10

For this analysis, the project team assumed the chargers would be distributed evenly along the circuits, because the specific location of where chargers might be installed is unknown. For some circuits, the location of a charging station could increase required reinforcements to support the load.

1.8 Cost Estimates

Distribution System Upgrade

Following the load flow modeling, the project team conducted a thorough cost assessment at the distribution level. This assessment was built upon cost data collected from local utilities, including necessary upgrades to transformers, substations, and distribution circuits. Working with participating utilities and available industry cost data, the project team calculated a per circuit average cost of $7.42 million for every new circuit, with detailed assumptions shown in Table 6.

Table 6. Assumptions used to calculate costs per circuit for new circuit in Washington

Category		Value
Average Length per Circuit		55000 ft.
Underground	15%	$600/ft.
Overhead	85%	$50/ft.
Switches	18	$8,100 (Unit)
Contingency		20%
Total		$7,419,000

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Circuits were analyzed individually to find excess EV load based on their configuration. Excess EV load was summed to the utility level. Circuit and substation transformer counts were calculated from the utility's excess EV load based on that utility's configurations. Utility configurations correspond to specific costs that were used to calculate the costs for new circuit buildout and additional substation transformers. The average costs are shown in Table 7. Finally, circuit buildout and substation transformers are summed to calculate the total distribution upgrade costs, at utility level.

Table 7. Average costs per additional substation transformer required

Circuit Voltage (kV)	Transformer size (MVA)	Cost
26.4	75	$ 9,000,000
12	25	$ 6,500,000
13.8	20	$ 5,000,000

Utility data was not available in all of Washington's CBGs. Filling in these data gaps required the project team to develop a methodology to estimate distribution upgrade costs at the CBG level. The methodology created first took utility level total upgrade costs and distributed those costs to the utility's respective circuits. The per-circuit upgrade costs were then reallocated at the transformer level using a transformer percent of total circuit transformer capacity. The total distribution upgrade costs per CBG is thus the sum of the upgrade costs of all transformers contained in the CBG. This process is described in Equation 7.

Equation 7: Calculation of distribution upgrade costs at CBG

$$Cost_{Transformer,i} = \frac{Cost_{Utility} \times Capacity_{Transformer,i}}{Number\ of\ Feeders\ in\ a\ Utility\ Service\ Territory \times \sum_{Feeder} Capacity_{Transformer}}$$

$$Cost_{CBG} = \sum_{CBG} Cost_{Transformer,i}$$

Through association analysis, the project team found that the distribution system upgrade costs at the CBG level were well correlated with transportation peak loads, as shown later in this report. For CBGs for which utility data were not available, the project team used the regression derived from this relationship to fill in the gaps, and the total system distribution system upgrade costs were then aggregated up to a statewide level.

Transmission System Upgrade

The projected increase in distribution load can potentially impact the transmission system in a significant way. Transmission lines are sometimes referred to as an "interstate highway system" for electricity, which moves electricity more efficiently over long distances from power sources to large industries or transmission substations where the voltage is reduced, and the power is distributed to homes and businesses. In the state of Washington, PSE[21] oversees over 2,700 miles of transmission lines and 353 substations and SCL[22] owns 653 circuit miles of high-voltage transmission lines (typically 230,000, or 115,000 volts). While there are other smaller utilities in Washington that manage or operate their own transmission system, the majority of the

[21] Puget Sound Energy, Transmission Services. Available at: https://www.pse.com/en/pages/transmission
[22] Seattle City Light, Transmission Services. Available at: https://seattle.gov/city-light/about-us/working-with-us/transmission-services

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other high-voltage transmission in Washington is owned and operated by the Bonneville Power Administration (BPA), with over 15,000 miles of transmission lines across the Pacific Northwest region.[23]

Adding new transmission capacity is a complicated process and can require a lead-time of up to a decade. Because transmission systems often cross state borders, they require strategic planning and coordination beyond the state level. Jurisdictional and non-jurisdictional entities in the Pacific Northwest and Intermountain West have formed a single transmission planning association, NorthernGrid,[24] to facilitate transmission planning and compliance with the Federal Energy Regulatory Commission (FERC) requirements across the region. BPA and major IOUs and COUs in Washington are active members of NorthernGrid, and the UTC and Commerce are members of the Enrolled Parties and States Committee.

To fully grasp the impact of EV adoption on the transmission system, extensive modeling across multiple jurisdictions and states will be required. Since no relevant data was available from participating utilities through the development of WUSCIA, only a high-level cost estimation for transmission system upgrades has been included. The project team assumed the capital costs to build out the transmission system are somewhat proportional to that of the distribution system, based on a recent study that was published by the University of Texas at Austin.[25] This study, Trends in Transmission, Distribution, and Administration Costs for U.S. Investor Owned Electric Utilities, applied more than 200 project records reported by the FERC and isolated costs associated with each step in the energy delivery process. The costs for distribution, transmission, and administration are all linearly correlated to the number of customers in a utility's territory. The unit costs for transmission and distribution systems derived from this study are summarized in Table 8 and the capital cost to build out the transmission system[26] is roughly 40% that of the distribution system.

Table 8. Unit costs for transmission and distribution systems

Category	Transmission, $/Customer-Year	Distribution, $/Customer-Year
Capital	$75	$189
Operation & Maintenance	$45	$102
Total Cost	$120	$291

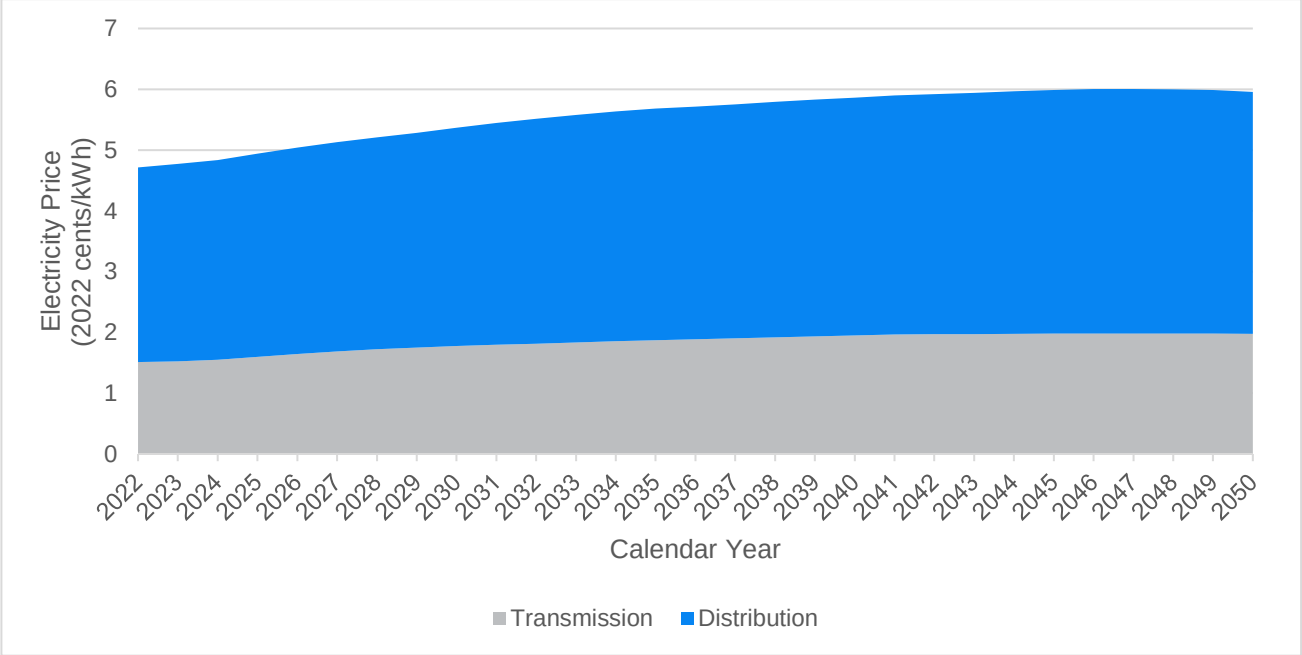
To verify this correlation, the project team also explored the latest Annual Energy Outlook (AEO2023) by the U.S. Energy Information Administration (EIA).[27] In the latest AEO projection of power sector trends, as shown in Figure 13, electricity prices have been broken down by service categories, including generation, transmission, and distribution. The contributions from transmission and distribution remain steady, with transmission being approximately half of the distribution.

[23] Bonneville Power Administration, Transmission Services. Available at: https://www.bpa.gov/energy-and-services/transmission
[24] NorthernGrid, Purpose. Available at: https://www.northerngrid.net/northerngrid/purpose/
[25] Fares, L., Robert, King, Carey W., "Trends in Transmission, Distribution, and Administration Costs for U.S. Investor Owned Electric Utilities," White Paper UTEI/2016-06-1, 2016. Available at http://energy.utexas.edu/the-full-cost-of-electricity-fce/
[26] Transmission capital costs include the cost of land and land use rights, substation equipment, transmission towers, conductors, and several other capital costs associated with transmission.
[27] Annual Energy Outlook 2023, Table 8: Electricity Supply, Disposition, Prices, and Emissions, available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2023&region=0-0&cases=ref2023&start=2021&end=2050&f=A&linechart=&sourcekey=0

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Assuming electricity prices are proportional to the capital expenditure to build out this infrastructure, the proportion between transmission and distribution shown in the AEO2023 projection is quite consistent with the cost study discussed earlier. Therefore, the project team applied an adjustment factor of 0.4 to account for transmission system upgrade costs. Similarly, the system operation and maintenance costs up to 2050 were also estimated based on the capital costs using the relationship derived from Table 8.

Figure 13. Composition of electricity price by service category: transmission, and distribution



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Results and Findings

1.9 Load Impact from Transportation Electrification

Using the given methodology, the peak EV load in each CBG across the three charging cases was calculated. By comparing the nameplate standard in Figure 14 with the other two charging scenarios as shown in Figure 15 and Figure 16, the peak loads in the managed scenario are typically around 70-80% of those of the nameplate, while the peak loads for the distributed scenario are typically round 90-95% of the nameplate peaks. As expected, the areas with high EV charging loads are the ones with the most chargers or more high-powered chargers. In particular, locations with MD and HD public charging show up as the highest load CBGs, as well as those with transit depots or high numbers of MD and HD depot chargers. Additionally, high-population CBGs in urban cores like Seattle, Vancouver, and Spokane also show high loading from residential or multifamily charging.

Figure 14. Peak charging load in each census block group for the nameplate standard

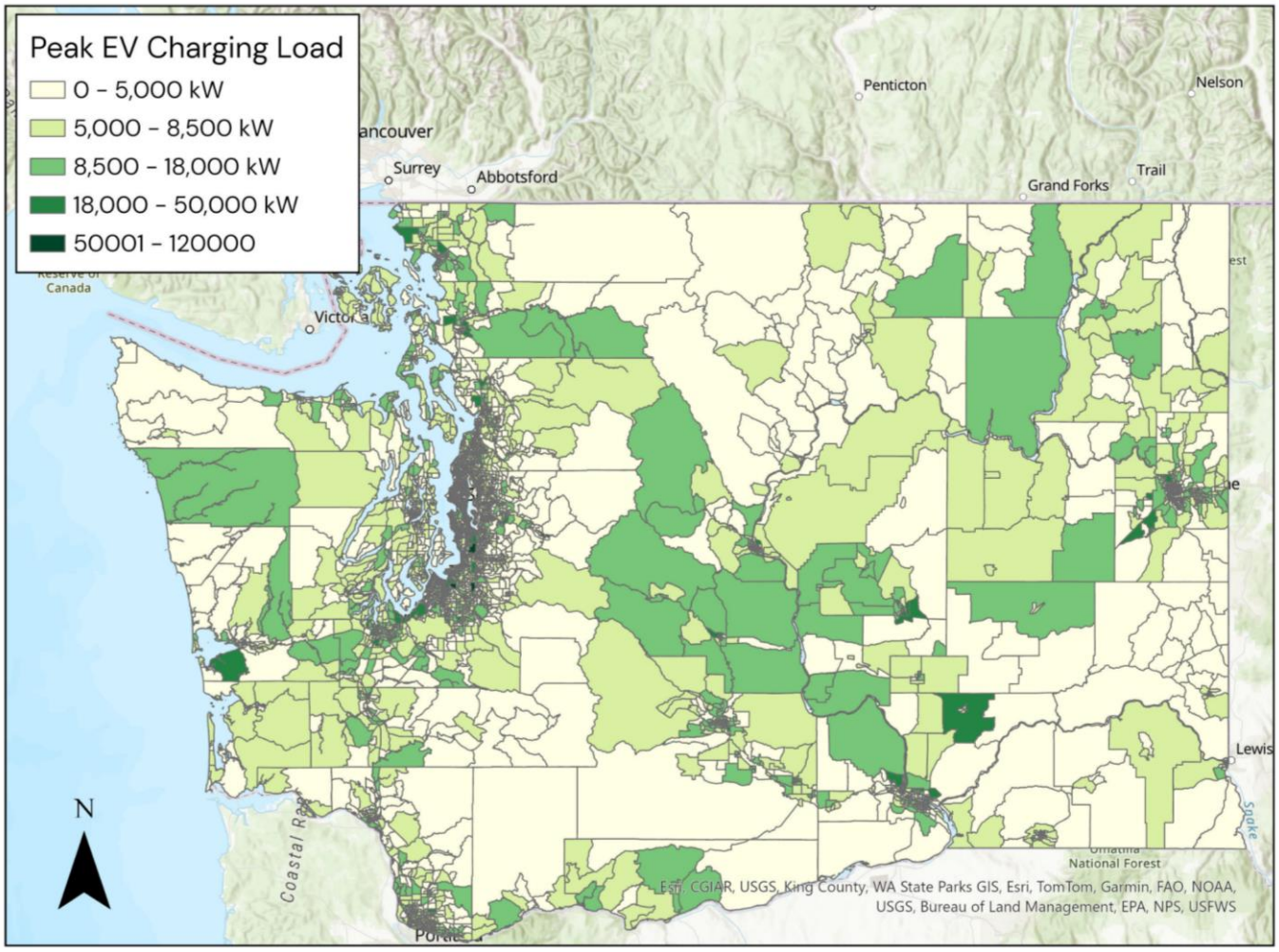


Figure 15. Peak charging load in each census block group for the distributed scenario

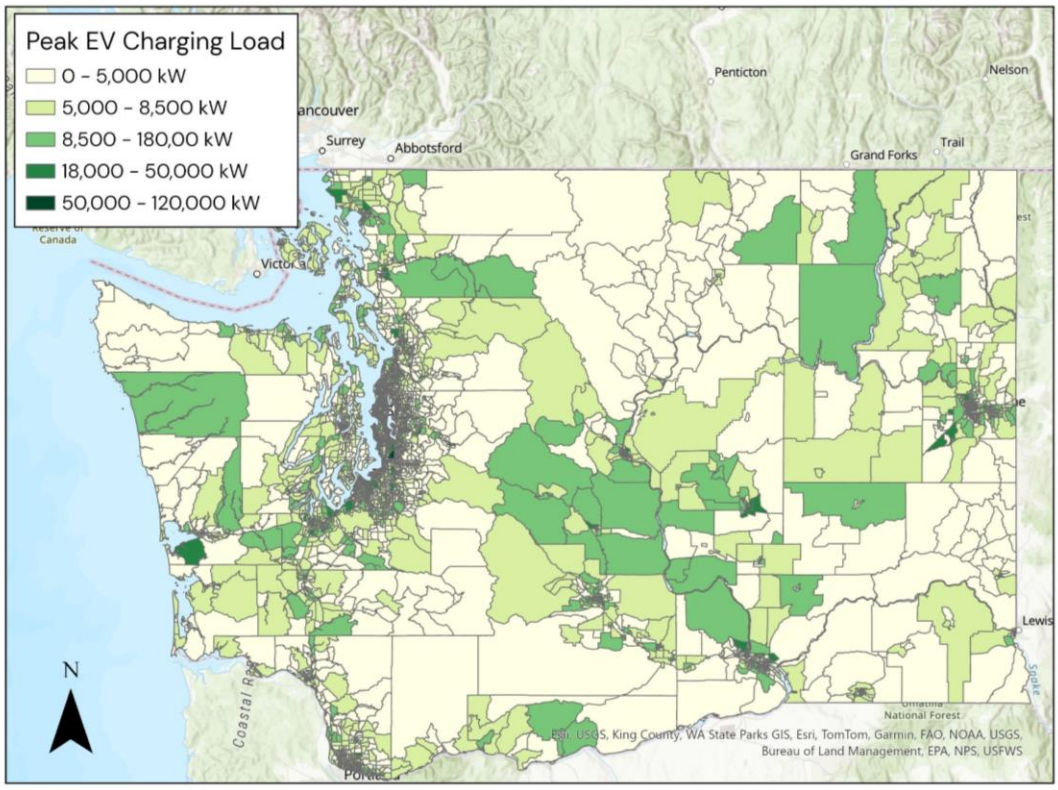
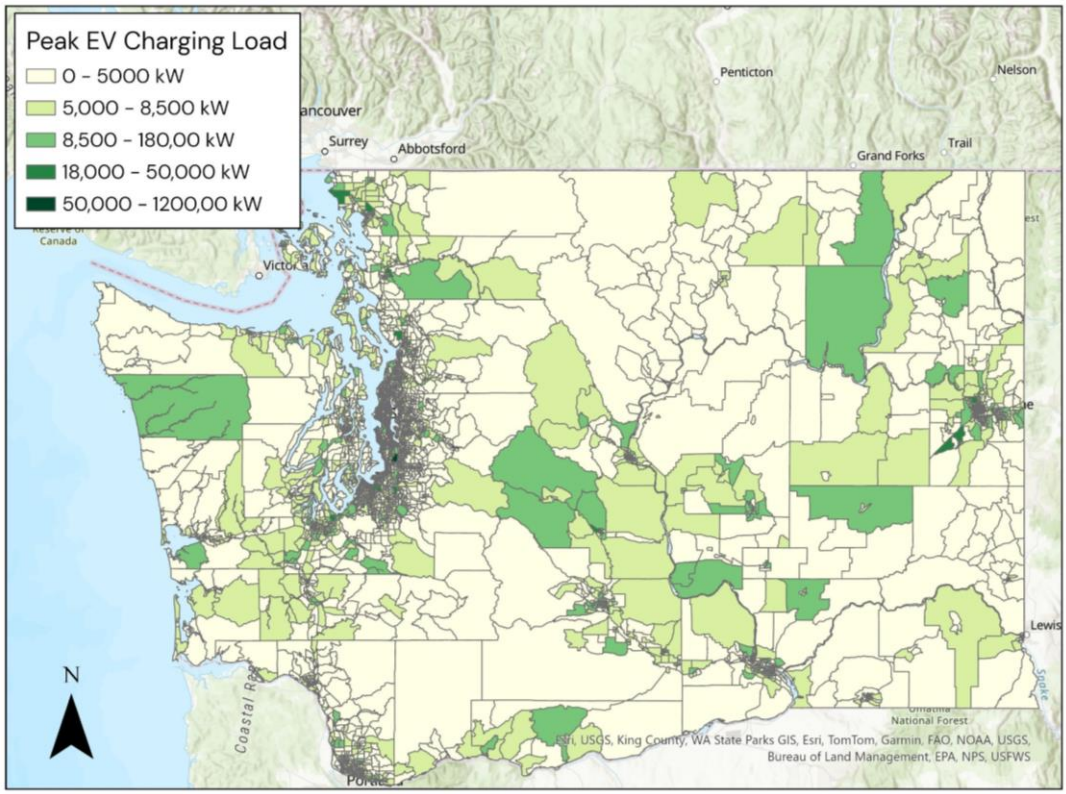


Figure 16. Peak charging load in each census block group for the managed scenario

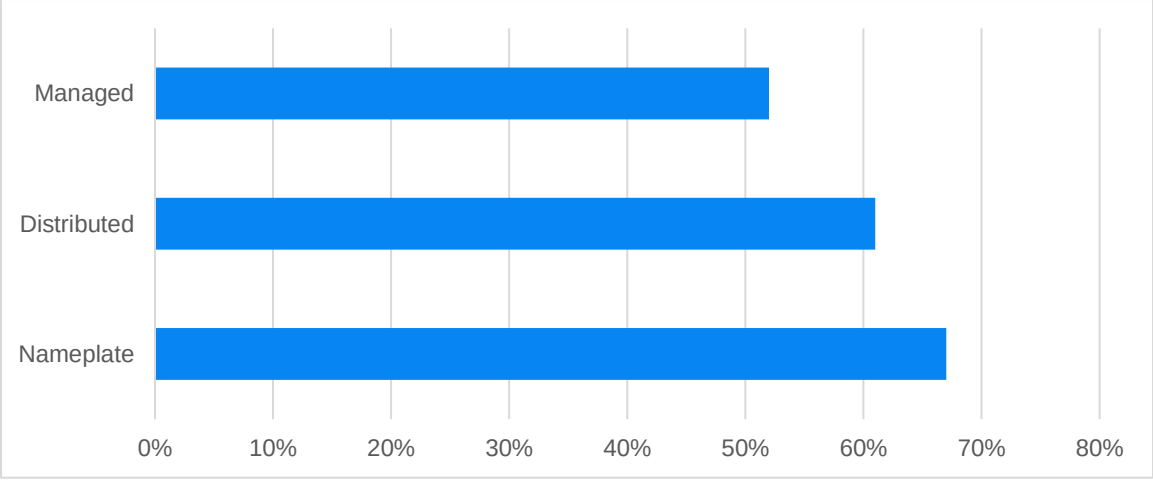


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1.10 Circuit and Transformer Overload

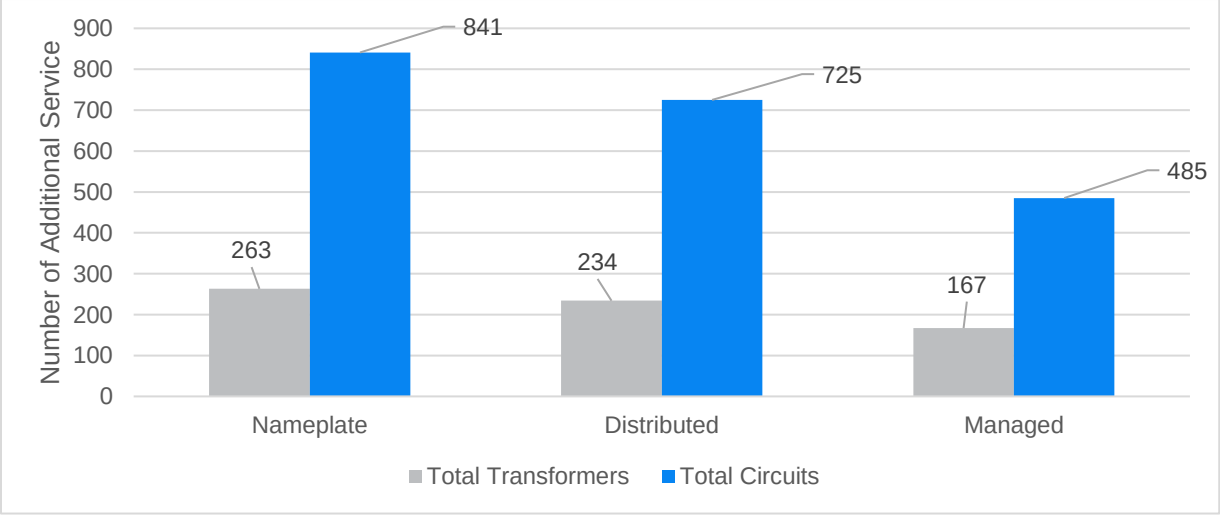
There were approximately 1,200 circuits analyzed through utility modeling. The service territories covered by these circuits are home to roughly 47% of Washington's population. Based on circuit and substation transformer limitations, as shown in Figure 17, load flow analysis showed existing circuits overloaded by 67% at nameplate, 61% at distributed and 52% at managed scenario loads. Depending on the excess loads by each charging case, correcting the overload will require increasing the number of circuits by 70% at nameplate, 60% at distributed, and 40% at managed scenarios. Thus, managed scenarios require fewer upgrades per overload compared to nameplate or distributed scenarios. The total capacity upgrades of Washington's distribution grids due to transportation electrification under the nameplate standard, distributed scenario, and managed scenario are 7.0 GW, 5.8 GW, and 4.1 GW, respectively.

Figure 17. Percentage of overloaded circuits by charging case



The number of substation transformers and new circuits required to serve the load was calculated based on the percentage of overloading on each circuit, based on the input from participating utilities and standard engineering practices. Figure 18 summarizes the number of new circuits and substation transformers required to serve the load based on the scenario.

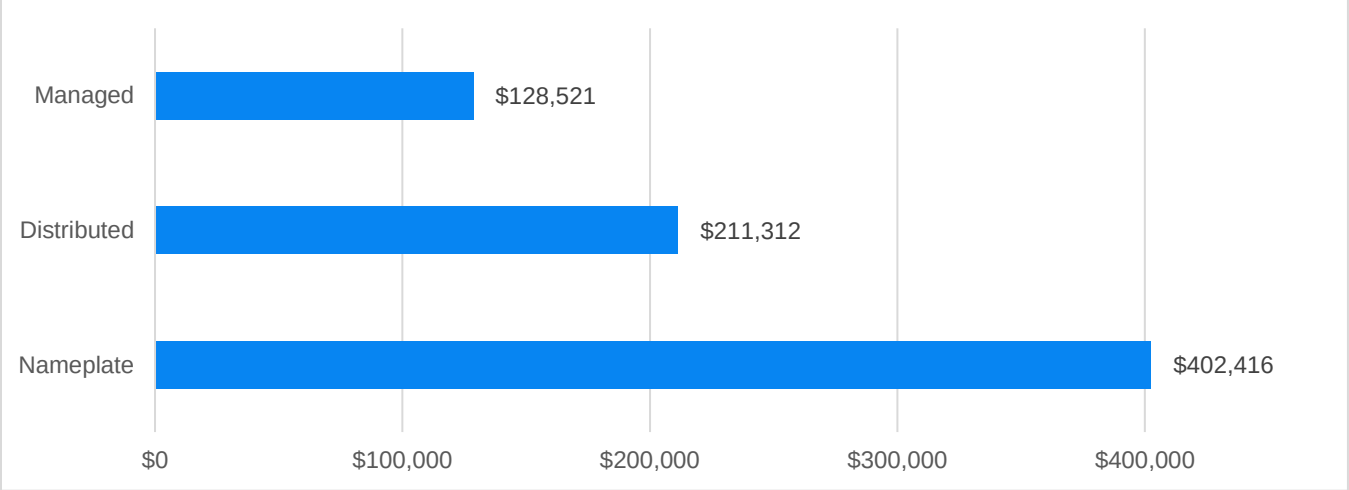
Figure 18. Number of substation transformers and new circuits required to serve loads by cases



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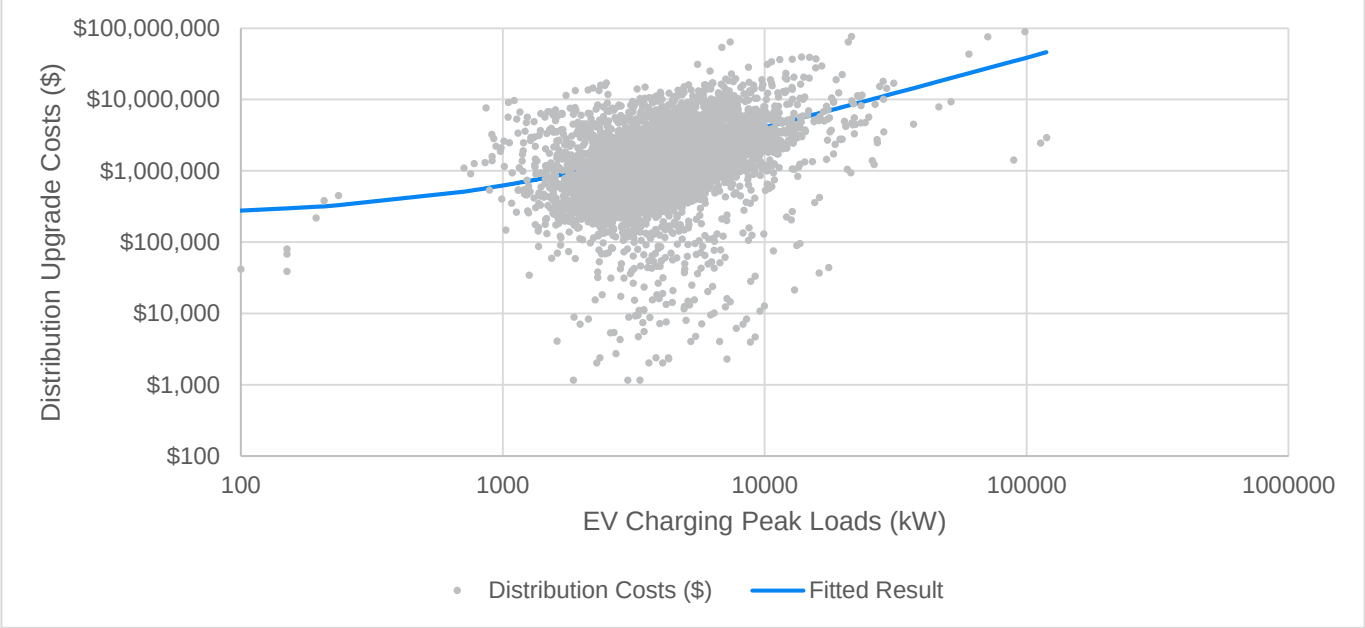
The total costs to upgrade the distribution grid were summarized at the utility level. On average, the costs to upgrade under nameplate standard were almost two times higher than distributed, and the distributed scenario was over one and a half times higher than managed. The same trends were observed at the average distribution system upgrade cost per circuit allocated to the system, as shown in Figure 19.

Figure 19. Average upgrade costs per circuit by charging scenario



Since there are CBGs for which utility data were not available, correlation between distribution upgrade costs and peak loads for transportation load at CBG level were used to derive stand-in estimates. The correlation between the two variables based on available utility data is shown in Figure 20.

Figure 20. Correlation between distribution upgrade costs at CBG level vs. the charging peaks from EV loads



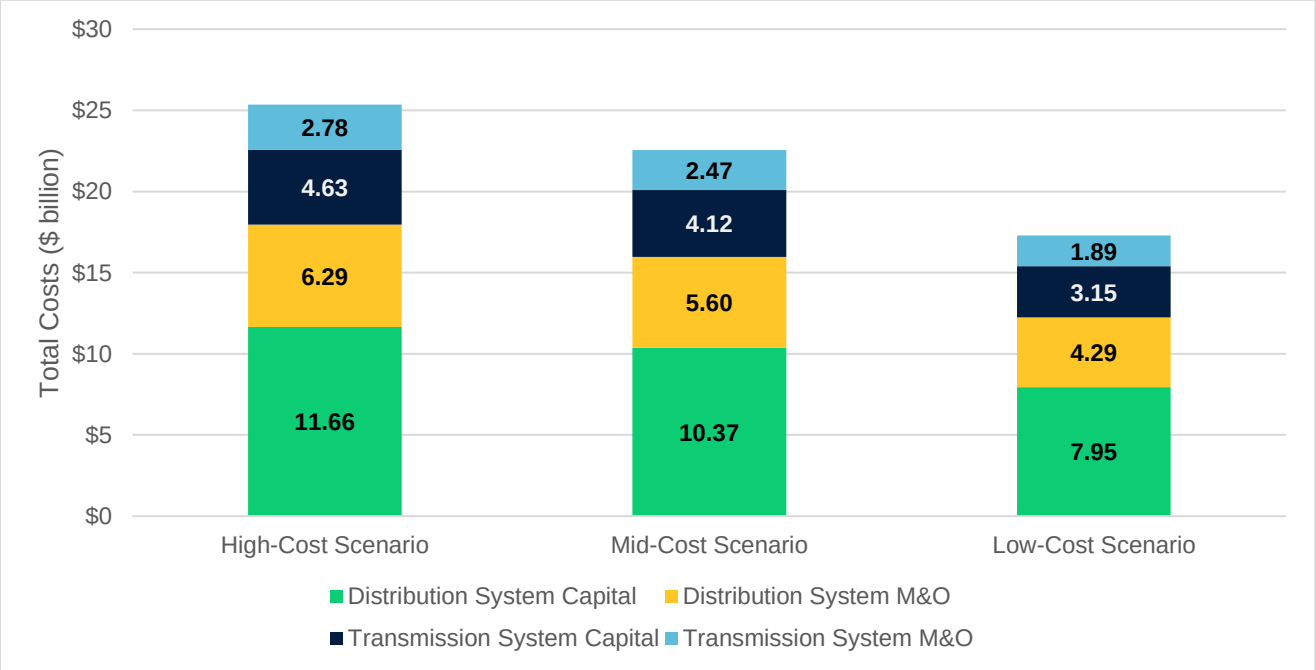
Each charging case that was studied corresponded to one cost scenario: the nameplate standard represents the high-cost scenario for upgrading all utility-side charging infrastructure, the distributed and managed scenarios correspond to the mid-cost and low-cost scenarios, respectively. Table 9 summarizes the total costs to upgrade the distribution system for utilities that provided their load flow models, as well as the fitted statewide total costs after applying the above correlation.

Table 9. Fitted statewide total distribution system upgrade costs by charging cases and corresponding cost scenarios

Charging Case	Corresponding Cost Scenario	Calculated Total Costs Based on Utility-Provided Data	Fitted Statewide Total Costs
Nameplate	High	$5.46 Billion	$11.66 Billion
Distributed	Mid	$4.46 Billion	$10.37 Billion
Managed	Low	$3.01 Billion	$7.95 Billion

The project team then used the relationship presented in Table 8 to calculate the total costs across the state. The results shown in Figure 21 include all costs associated with planning and installation activities up to the year 2035, as well as the maintenance and operation (M&O) costs anticipated through 2050. The three cost scenarios are summarized in Figure 21.

Figure 21. Statewide high-, mid-, and low-cost scenarios associated with utility-side infrastructure upgrades to support transportation electrification



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Discussion

Transportation electrification is critical to achieving Washington's emissions reduction goals. To facilitate this transition, the WUSCIA serves to better understand the financial impact of the grid upgrades it necessitates. The circuit-level profile from this study can also assist utilities in identifying overloaded circuits and prioritizing distribution planning, which may help reduce costs if implemented carefully. The WUSCIA has estimated the total costs to upgrade the statewide distribution grid is approximately $10.4 billion dollars (mid-cost scenario), assuming charging activities will be mostly driven by existing driving patterns. Moreover, the implementation of managed charging programs and policies to incentivize off-peak charging can further reduce this cost by almost a quarter (low-cost scenario).

Utility Practices

A key takeaway of the WUSCIA is that using the nameplate standard to estimate upgrading costs leaves utilities with an upper-bound estimation far higher than what is required to serve customer demand. The nameplate standard assumes that residential, commercial, and fleet charging all occur simultaneously and will have coinciding peak charging periods. In reality, while residential charging peaks between 5 p.m. and 11 p.m. commercial and fleet charging patterns can vary. For instance, school and transit buses are usually charged during business hours or overnight. In addition to coinciding peaks, the nameplate standard assumes a maximum charging load from all vehicles being consistently charged during the same peak period across each category. Average daily travel in the United States is estimated to be between 20 to 30 miles, whereas most available battery electric vehicles offer ranges between 110 and 300 miles, indicating that most drivers will not need to charge their vehicles on a daily basis.[28] By taking a worst-case scenario approach that assumes a maximum charging load, the nameplate standard vastly overestimates electric demand, and therefore, the cost of upgrading grid infrastructure to support this demand. Based on the analysis, the costs associated with upgrading circuits alone under the nameplate scenario could be 90% to 220% greater than in other scenarios.

This work also highlights the importance of managed charging. Prior to WUSCIA, many utilities have launched pilot programs for fleet electrification and charging to gain customers insights that will guide future strategy design for managing load increases. These programs focus on load management through demand response and other incentive-based strategies. That said, workplace and public charging are considered essential for relieving the burden from at-home charging during evening peak hours and providing access to drivers without home charging. In the future, utilities may also work with MHD fleets to explore possibilities to encourage off-peak charging for trucks and buses.

Accounting for vehicle class differences as they relate to charging demand is also critical to effectively addressing load increases in future grid planning. Though the cumulative system load from LDVs is much higher than that of the MHD sector, this load is also well distributed across most of the state's electrical infrastructure. When new LDVs are added to the grid, the increase in demand usually does not necessitate any major upgrades and can sometimes be absorbed by residential and small-scale generation, such as solar photovoltaic. On the other hand, MHD load tends to be concentrated in fewer CBGs, primarily along trucking corridors and major transit routes. This concentration effect, along with MHD chargers having higher rated capacities, leads to much higher energy demand.

[28] At a Glance: Electric Vehicles, Department of Energy, 2023. Available at: https://afdc.energy.gov/files/u/publication/electric-drive_vehicles.pdf

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In turn, the MHD charging demand increases the likelihood of upgrades being needed in the distribution system, including upgrading an existing substation or adding a new one. LDV charging typically uses L1 or L2 chargers, which have ranges at or below 19.2 kW. On average, CBGs in Washington have around 1,600 residents. If half the residents purchase an EV and install a L2 kW at-home charger, the additional load to the grid is about 15 MW per CBG, which may necessitate a substation upgrade or new addition that could take anywhere between $3 million to $35 million dollars.[29] In a populated residential area, this may be an extreme high-usage case as normally L2 residential chargers are installed at much lower density. A HD truck stop with 15 trucks using MW chargers all at once requires the same amount of additional capacity. The latter scenario is more likely to occur due to the nature of truck operations and the design blueprint of MHD charging hubs, and could therefore trigger more substantial grid upgrades than residential charging.

Utilities must also consider investing in infrastructure upgrades soon because of extended project lead times. Substation upgrades can take over a year, whereas a substation addition can take anywhere from 2-4 years and transmission can take up to a decade. If utilities hope to timely comply with state regulations related to MHD fleets, infrastructure upgrade planning should receive prompt attention. This applies particularly to cases involving land siting for new installations, which tend to have the longest lead times. Since land siting and purchasing is often done by service providers depending on installation type, identifying and building out these cross-collaborations and partnerships should also be emphasized. On the customer side, make-ready programs across the U.S. have proven efficient and effective to install EVSEs for residential and commercial customers. Similar streamlined practices should be considered for utility-side infrastructure upgrade.

Financial Impact

An important question when planning for grid upgrades is how investments will impact ratepayers. Because of how regulated utilities are structured, costs resulting from improvements in service may be borne largely by ratepayers through higher electricity bills. If not managed properly, EVSE investments could pose a considerable burden on ratepayers and the broader economy as EVSE-related infrastructural development scales. Opportunities are available to utilities to mitigate some of this burden. Significant (more than 30%) cost reduction was observed for this study under the statewide low-cost scenarios, assuming a large-scale implementation of managed charging programs. Such efforts will make the overall impact on ratepayers more manageable and justifiable given the long-term benefits. Several state agencies and utilities are exploring these strategies through pilot programs, laying the foundation for future improvements based on data-driven insights. For example, in 2017, the UTC issued a policy and interpretive statement regarding the regulation of electric vehicle charging stations. This policy strongly encourages measures such as time-of-use or dynamic pricing to promote off-peak charging.[30] Since then, PSE launched its Flex EV program in 2023, which allows EV

[29] National Renewable Energy Laboratory (NREL), Perspectives on Charging Medium- and Heavy-Duty Electric Vehicles, 2021. Available at: https://research-hub.nrel.gov/en/publications/perspectives-on-charging-medium-and-heavy-duty-electric-vehicles

[30] Washington Utilities and Transportation Commission, Policy and Interpretive Statement Concerning Commission Regulation of Electric Vehicle Charging Services, 2017. Available at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=147&year=2016&docketNumber=160799

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owners to adjust their charging schedules during high demand periods.[31] Clark Public Utilities implemented the Electric Vehicle Managed Charging Program to manage electric load and optimize grid efficiency.[32]

The eventual impact on individual ratepayers will vary greatly depending on the investments made by each individual utility to integrate and serve EV load. Utilities can mitigate ratepayer impacts by promoting policies and incentives to move EV charging off-peak, such as managed charging, and by investing in EV infrastructure in a manner that is roughly commensurate with the anticipated revenue EV charging will generate. It is also noteworthy that the electric utility grid investments discussed in this study are long-term investments that will be paid over 30 years through utility rates. Some of these investments can be incorporated into regular grid improvement and maintenance. For example, PSE reported in 2022 that approximately $3.1 billion was spent on reliability and service upgrades over a four-year period.[33]

Another way to relieve burdens related to infrastructure upgrade is the integration of distributed energy resources (DER). Utility operations in Washington are driven by two main regulations. CETA, passed in 2019, requires all utilities to eliminate carbon emissions from their energy resources by 2045.[34] It includes a requirement to ending use of coal-fired power generation after 2025 and achieving carbon neutrality by 2030. The Energy Efficiency Resource Standard (EERS) is another mandatory standard that requires qualifying utilities to meet some portion of their electricity demand through energy efficiency.[35] As such, current utility planning revolves around integrating more DERs, with a particular focus on residential and commercial solar in Washington and meeting the state's increasing electricity demand by augmenting pre-established practices related to energy efficiency. Due to limited DER-related information during the development of WUSCIA, DER forecasting was not accounted for in utility load flow modeling. As the adoption of distributed energy resources such as residential and commercial solar, battery energy storage systems (BESS), and wind generation, the availability of generation on the distribution grid will increase and can be utilized to provide load relief when those resources are operating. Utilities could also leverage virtual power plants (VPPs) to create a network of medium-scale power units, supporting overall distribution and transmission planning.[36] A Department of Energy study suggests that deploying 80 to 160 GW of VPPs by 2030 could enhance grid capacity for rapid electrification, reduce reliance on peaking power plants, and lower overall grid costs.[37]

In addition, state and public agencies in Washington could secure federal funding and leverage incentive programs or private investment to offset these costs. For instance, as part of the Bipartisan Infrastructure Law, $10.5 billion is available through the Grid Resilience and Innovation Partnerships (GRIP) Program to enhance

[31] Puget Sound Energy, Flex EV. Available at: https://www.pse.com/en/rebates/PSE-flex/flex-ev
[32] Clark Public Utilities, Electric Vehicle Managed Charging Program. Available at: https://www.clarkpublicutilities.com/residential-customers/reduce-energy-waste-and-lower-your-bill/all-rebates-incentives-and-low-interest-loans/electric-vehicle-managed-charging-program/
[33] Puget Sound Energy, Puget Sound Energy Files Three-year Rate Proposal, 2022. Available at: https://www.pse.com/en/press-release/details/Puget-Sound-Energy-files-three-year-rate-proposal
[34] Washington Utilities and Transportation Commission, Clean Energy Transformation Act. Available at: https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act
[35] Washington State Legislature, RCW 19.285.040: Energy Conservation and Renewable Energy Targets. Available at: https://app.leg.wa.gov/RCW/default.aspx?cite=19.285.040
[36] Evergreen Collaborative, Five Ways States Can Unlock Virtual Power Plants for Grid Flexibility and Decarbonization, 2024. Available at: https://collaborative.evergreenaction.com/memos/five-ways-states-can-unlock-virtual-power-plants-for-grid-flexibility-and-decarbonization
[37] U.S. Department of Energy, The Pathway to: Virtual Power Plants Commercial Liftoff, 2023. Available at: https://liftoff.energy.gov/vpp/

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grid flexibility and improve the resilience of the power system against growing threats of extreme weather and climate change.[38] The Title 17 Clean Energy Financing Program is also available for transmission developers to provide efficient electrical generation, transmission, and distribution technology. Industrial and large commercial customers are expected to contribute more than residential customers, particularly those with low incomes. Payments from the Climate Commitment Act (CCA) could be reinvested in communities to help ease financial burdens for low- and medium-income households. This market-based cap-and-invest program requires the state's largest polluters to reduce GHG emissions. The CCA is already expanding the state's weatherization program for low-income families to improve energy efficiency and reduce utility bills and providing $200 electric utility credits to eligible households in a separate program.[39]

While the costs associated with utility infrastructure upgrades may seem substantial, the return on investment from transportation electrification cannot be neglected. Electrifying Washington's trucks alone is expected to result in $1.3 billion in health-related savings and $2.4 billion in annual net societal benefits stemming from reduced emissions, improved public health, and fuel savings.[40] By 2050, net societal benefits could amount to $24.9 billion, cumulatively. Moreover, populations living closer to heavy traffic roadways and having exposure to mobile source emissions experience a disproportionate share of environmental health burdens. [41] The statewide transportation goal will especially benefit residents in the overburdened communities. Customers directly affected by these upgrades will also benefit from lower driving costs with EVs. For instance, a battery electric vehicle in Washington can save $0.16 per mile, totaling over $1,000 annually for an average driver.[42] The Washington State Energy Strategy also projects that strong electrification and efficiency improvements could save the average energy customer about $132 annually by 2050.[43]

Finally, the cost estimates focused on the transportation sector, while the factors that drive utility-side infrastructure upgrades are more complicated. The AEO2023 projected that the transportation sector will only account for 3% of the total electricity sales in the US by 2035, and most of the demand will be driven by the industrial, commercial and residential sectors. Therefore, the actual incremental need for generation and capital upgrades will be impacted by electrification activities in other sectors. It is critical for the state to consider the aggregated impact from all activities when planning for transportation electrification.

The WUSCIA is structured to facilitate and support the involvement of local electric utilities in EVSE-related grid upgrade planning. The insights garnered from these engagements are intended to guide policymakers, including entities such as the Governor's Office, the State Legislature, the Department of Commerce, and the Utilities and Transportation Commission, on the allocation of resources for the necessary buildout and maintenance of EV infrastructure. By equipping these entities with robust and actionable data, the WUSCIA aims to align long-term transportation electrification with the state's sustainability goals.

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[38] Grid Deployment Office, Grid Resilience and Innovation Partnerships (GRIP) Program. Available at: https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program

[39] Washington Climate Action, Climate Commitment Act: Polluters Pay, Communities Benefit. Available at: https://climate.wa.gov/washington-climate-action-work/climate-commitment-act-polluters-pay-communities-benefit

[40] What the Advanced Clean Truck Rule Will Do for Washington, Union of Concerned Scientists, 2021. Available at: https://www.ucsusa.org/sites/default/files/2021-12/wa-clean-trucks-fact-sheet.pdf

[41] Washington State Department of Health, Washington Environmental Health Disparities Map. Available at: https://doh.wa.gov/data-and-statistical-reports/washington-tracking-network-wtn/washington-environmental-health-disparities-map

[42] U.S. Department of Energy, Local Fuel Savings. Available at: https://www.energy.gov/local-fuel-savings

[43] Washington State Department of Commerce, Washington State Energy Strategy, 2021. Available at: https://www.commerce.wa.gov/energy-policy/state-energy-strategy/

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Appendix A: Peak Load Comparison by CBGs

Six CBG profiles were selected to display how charger type contributes to the overall load at the peak hour (20 h) within the distributed scenario and managed scenarios.

Figure A1 — residential profile

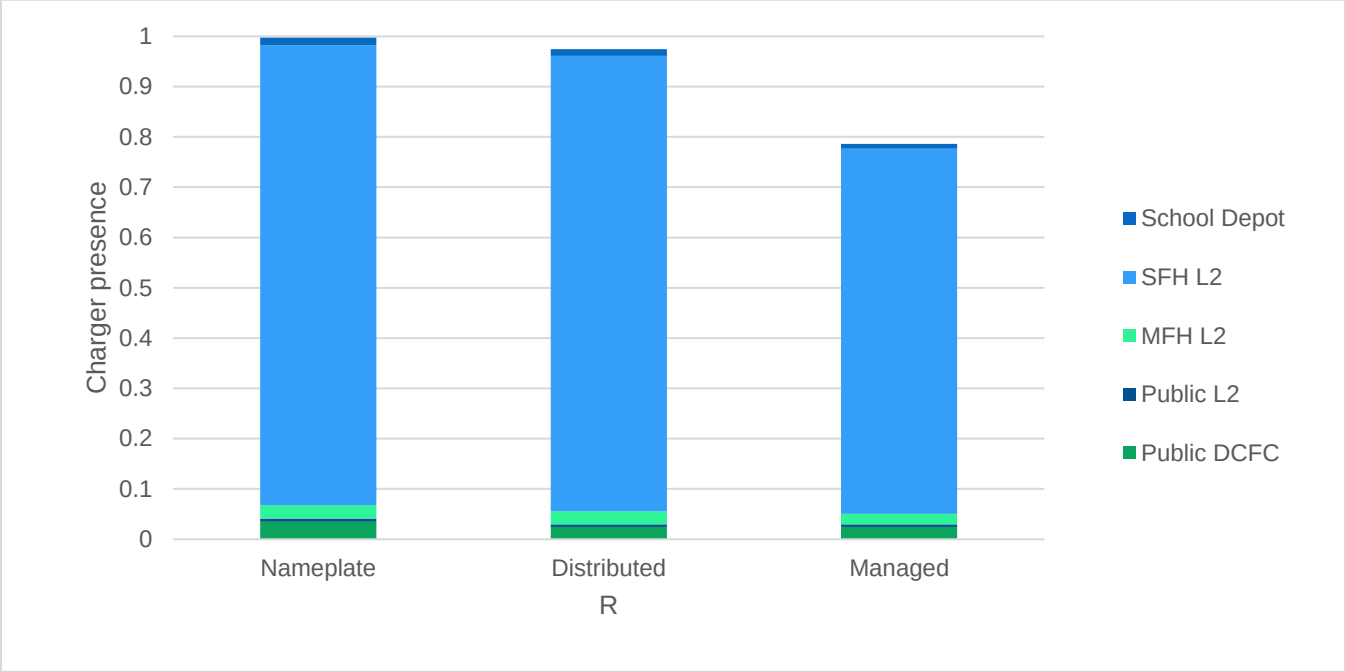
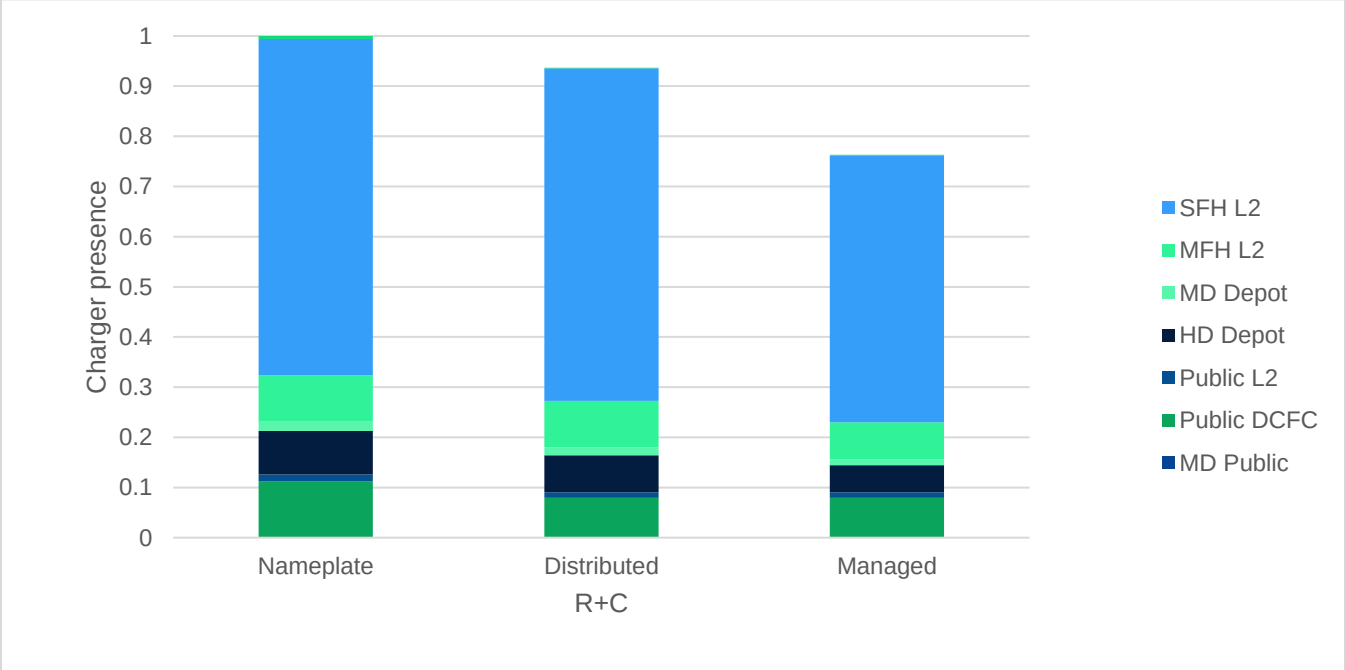


Figure A2 — residential and commercial profile



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Figure A3 — residential, commercial, and industrial profile

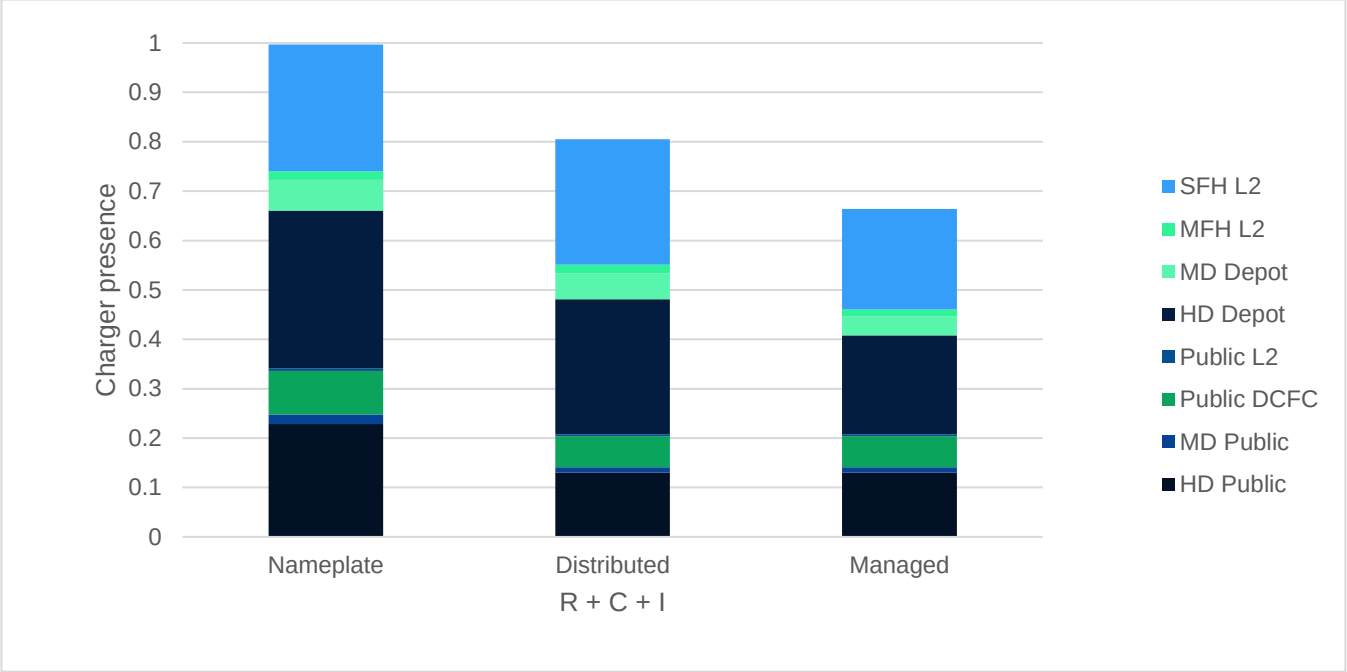
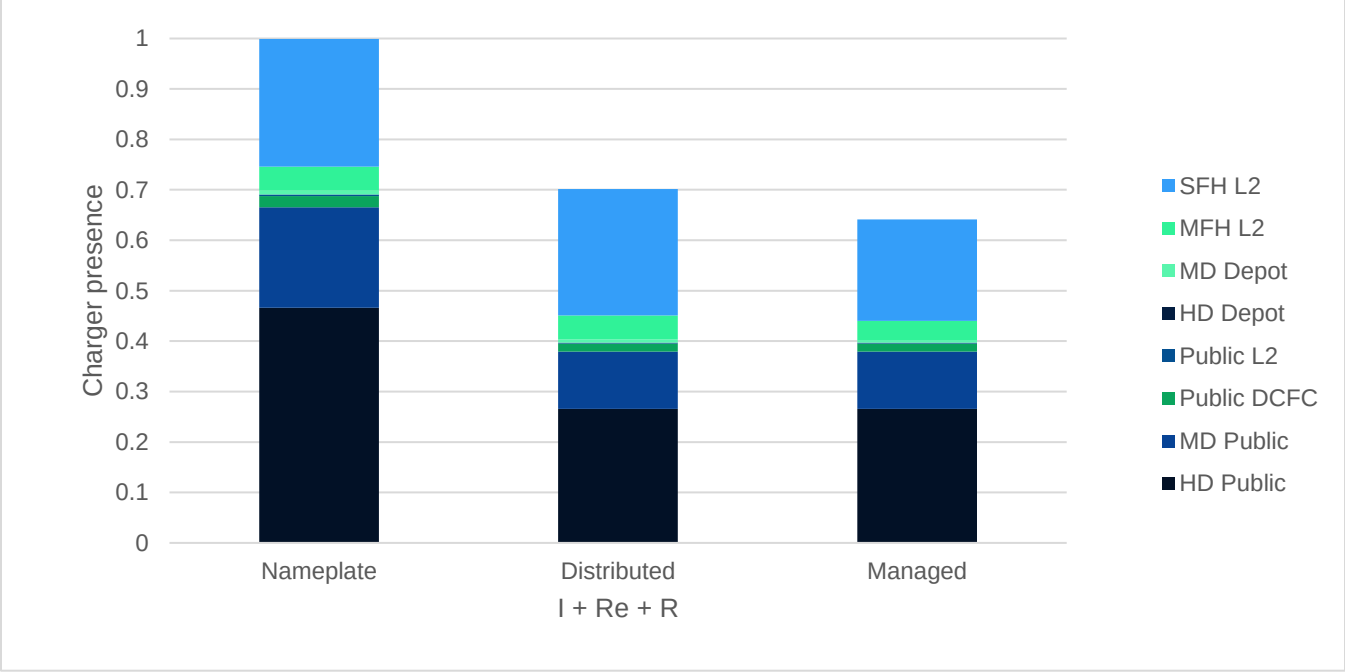


Figure A4 — industrial, retail, and residential profile



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Figure A5 — Truck hotspot profile

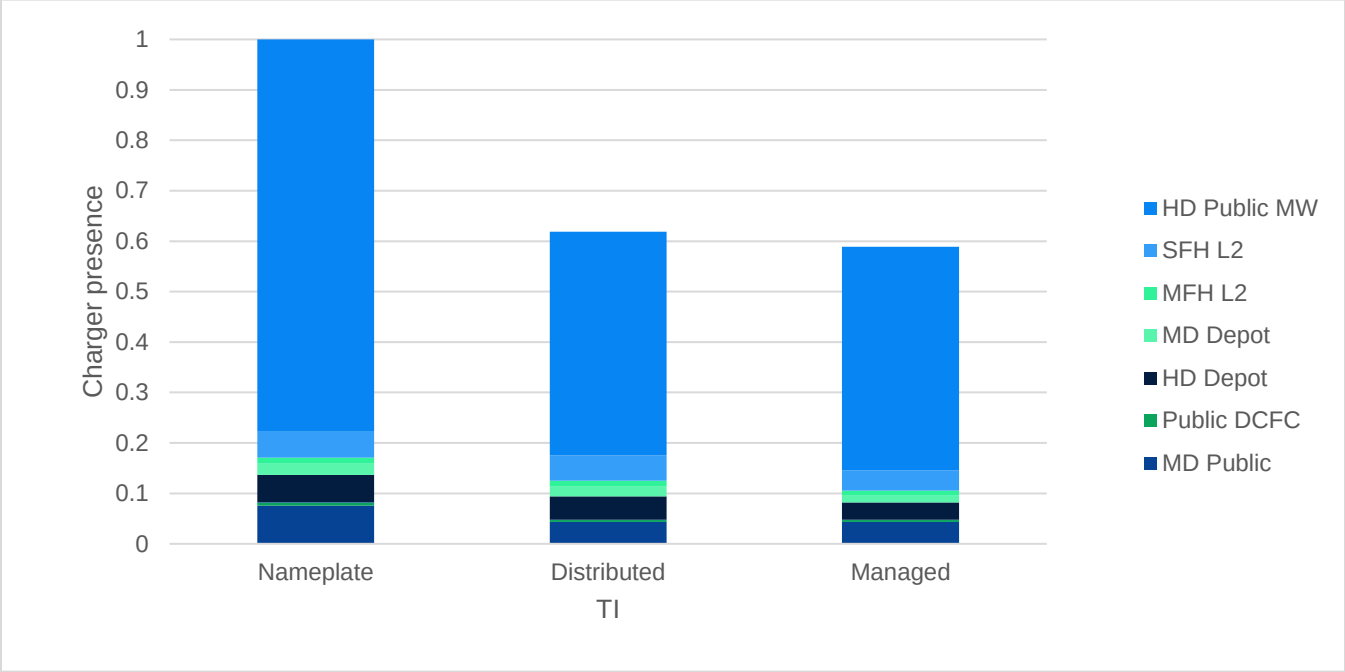
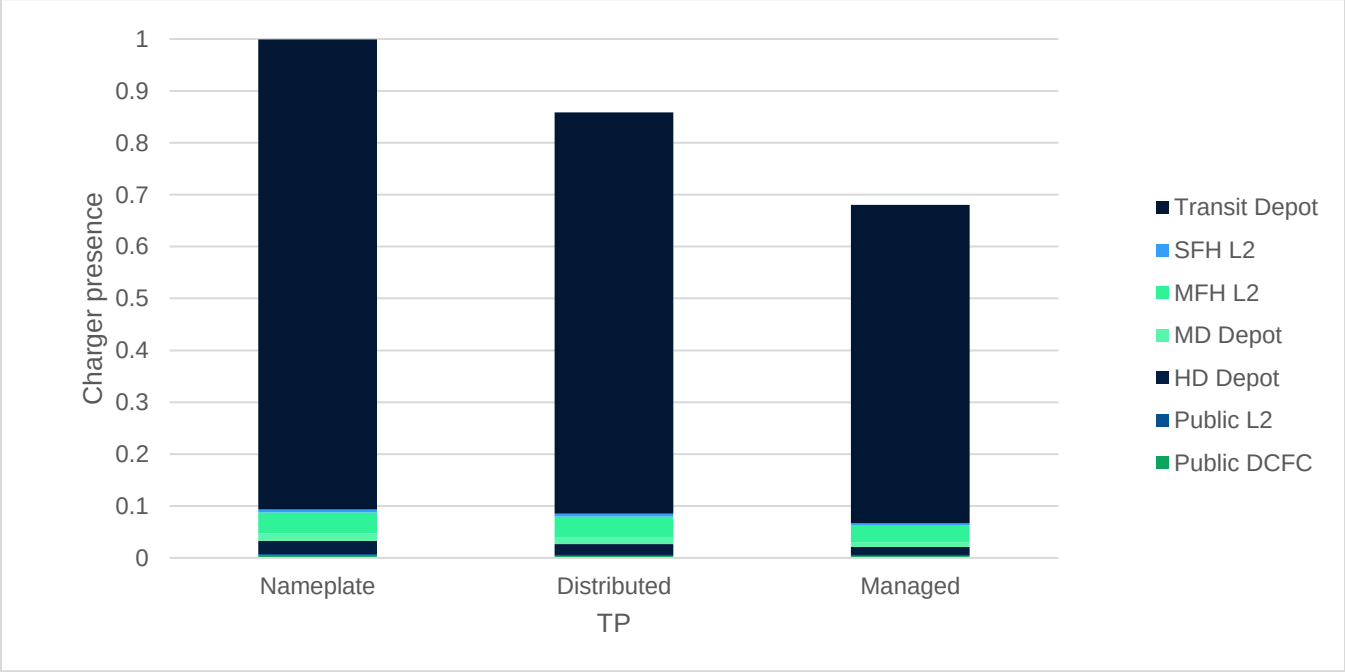


Figure A6 — Major transit agency depot profile



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Appendix B: Data Request Guide

1.11 Project Overview

To fulfill statewide clean transportation and climate goals, the Interagency Electric Vehicle Coordinating Council (EV Council), jointly led by the Washington State Department of Commerce (Commerce) and the Washington State Department of Transportation (WSDOT), developed the State's **Transportation Electrification Strategy** (TES) for the period up to 2035 (as outlined in RCW 43.392.040). This strategy involves a thorough evaluation of the state's infrastructure requirements, including electric vehicle supply equipment (EVSE), to accommodate the expected increase in zero-emission vehicles (ZEVs) on the roads over the coming decade. According to the final TES published in November 2023, under the Strong Electrification Policy scenario, the State of Washington requires more than 3 million charging ports by 2035 generating an evening peak load of 3.4 GW.

Given the substantial increase in load demand from the accelerated deployment of EV charging infrastructure, significant upgrades to the electrical infrastructure are inevitable on both the customer and utility sides of the meter. The Washington Utility-Side Charging Infrastructure Assessment (WUSCIA) is a strategic initiative designed to provide a comprehensive estimation of the net present value costs associated with EVSE-related infrastructure on the utility side of the meter. The WUSCIA focuses on projecting costs for planning and installation activities such as adding new distribution circuits, augmenting transformers to handle higher loads, and expanding or modernizing distribution substations for increased capacity, up to the year 2035. Additionally, it extends to evaluating the operational and maintenance costs anticipated through 2050. A key aspect of WUSCIA is to analyze the potential financial impacts on a diverse set of stakeholders, including utilities, ratepayers, electric vehicle service providers (EVSPs), and their customers. The outcomes of this project also aim to serve as the foundation to support an evidence-based decision-making process for funding necessary infrastructure buildout and maintenance for the State of Washington.

1.12 Utility Data Request

A critical component of the WUSCIA evaluation is to understand the typical costs associated with planning and installation activities and current assets and load information. Current load data will be combined with EV charging load projected by TES at Census Block Group (CBG) level to estimate the upgrades needed to support the statewide transportation electrification efforts. The project team, led by Commerce and the ICF consultant team, would like to invite utilities across the State to participate in this project to inform the development of WUSCIA. Participation of utilities will ensure that the evaluation can best reflect the EVSE-related grid upgrade needs for the State, and to support utility planning efforts in the next decade.

There are two types of data that the project team is requesting from the participating utilities: equipment costs and asset and load data, and the project team will try to accommodate different data sharing policies of each individual utilities throughout the process. As detailed in the Data Privacy, Sharing, and Purging section below, data shared by utilities will be labeled as Proprietary Information, accessible to the ICF consultant team only, and not be subject to the State of Washington Public Records Request.

When utilities submit cost data for equipment, the values can be directly input into a workbook that will be provided by the consultant team or can be submitted in existing file formats such as spreadsheets/workbooks or standards documentation used as reference when pricing system reinforcements and providing new service if that is more efficient. ICF will be able to extract data from multiple sources for aggregation purposes. Details of equipment cost data sharing instructions can be found in the Equipment Cost Data section. If pricing data is not readily available or the collection of said data would result in an

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excessive time or resource commitment, ICF will aggregate available pricing from other Washington state utilities and/or market data to estimate costs.

Utilities are also asked to provide asset data that identifies equipment at its spatial location in the field. We must know the spatial location so that the transportation load data can be tied to Census block groups. Utilities will also need to provide a load profile for each feeder/circuit on the day that feeder/circuit hits its peak load. More details are available in the Asset and Load Data section.

ICF will work with each participating utility to answer questions and provide support for data collection in an effort to obtain and parse the data efficiently and with minimal impact on the utility.

Data Requested

- Equipment cost data with loaded costs identified (categories and instructions included in the Equipment Cost Sheet)
    - Transformers, conductors, transmission, substation, DMS, other devices, and long-term costs
- Asset and load data
    - Circuit level 15-minute interval SCADA data (including load and power factor) for circuit peak day (24 hours)
    - GIS (geographic information system) asset data for all circuits (additional discussion can be found in the GIS Data section of this guide)
    - Utility Boundaries (preferably in a vector polygon GIS file)
    - Standard circuit capacity limitations at feeder head (loading and power factor)
    - Substation transformer loading capacity with ID corresponding to GIS data
    - If available, aggregated circuit level DER capacity at nameplate. (If available, individual DER 15-minute export data.)
    - Hosting capacity maps/analysis (if available)

Data Privacy, Sharing, and Purging

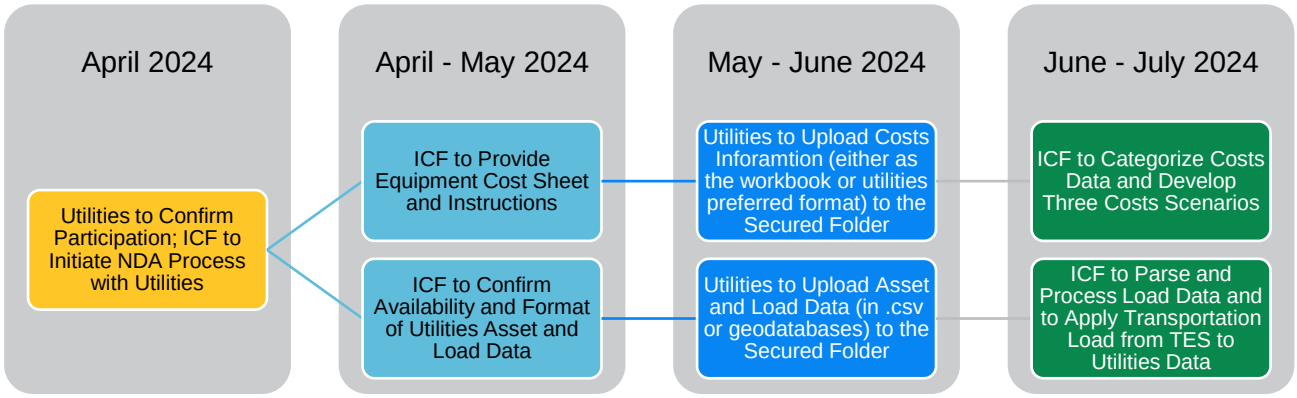
If needed, ICF will work with utilities to establish a non-disclosure agreement (NDA), which will be signed by both parties (ICF and the affected utility) to protect unauthorized data dissemination and outline restrictions on use of utilities data. Raw data collected from utilities will be stored on a secured Microsoft Teams site, set up by the ICF Information Security team. Each participating utility will receive a distinct link that will point to the folder to upload their data directly (the folder will only be accessible to the designated utility and the ICF consultant team). The unprocessed data will be stored only on the ICF domain and available to ICF consultant team members only, and not be shared with any outside parties, including Commerce. Any data shared under an NDA will be treated as proprietary information and not be subject to the State of Washington Public Records Request. Data collected from utilities will be purged and removed from the ICF site six months after the project close-out (expected December 2024).

Project Timeline

The initial data request will go out to utilities in April 2024. ICF expects to receive final confirmation from utilities whether they would participate in this project by the end of April. Over the course of May-June 2024,

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ICF will work with utilities to acquire and parse the required data. Data processing and analysis are expected to take place starting late June 2024, and the initial draft report will be available late July 2024.



1.13 Equipment Cost Data

As part of resource planning and cost assessment, ICF understands that each utility calculates operation, maintenance, and reinforcement costs differently. When compiling cost estimates for new services, utilities may include labor, expected maintenance, operating costs, or any combination of those categories folded into the per unit cost of equipment. When submitting the cost data, please indicate what costs are included in the per-unit or per-foot costs and include any maintenance, operating, or labor costs that are not included. Additionally, please indicate annual and lifetime costs for maintenance and operations. The Long-Term Costs tab in the Equipment Cost Sheet can be used to discuss these costs and describe equipment cost methodology if salient. If pricing data is not readily available, ICF will aggregate available pricing from other Washington state utilities and/or market data to estimate costs.

Each equipment tab has section to indicate what costs are included in the per unit cost of the equipment with a pull-down check box option as illustrated below:

What costs are included in the per unit equipment costs?
Please check all that apply

✓ **Maintenance**
Operation
Labor
Other **(Please describe other costs below)**

1.14 Asset and Load Data

When creating data sets for GIS data, it is preferred the data is processed to CSV files or geodatabases. A consistent file type will help mitigate data parsing and data extraction issues and increase efficiency. If it is not possible to extract data in the form of a CSV or geodatabase, an alternative data type would be an Excel spreadsheet or distribution model such as CYME, Synergi, or Windmil. If all the data is not available, or not all the equipment listed below is modeled in the GIS database, ICF can make assumptions based on aggregated data from other Washington State utilities as well as standard industry practice when appropriate. ICF can assist in GIS data collection in order to minimize the impact of the request.

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The following equipment list represents the optimal data we aim to receive. The ICF team prefers a comprehensive data submission of the distribution system to ensure the data is complete. For substation data, ICF understands that the substation may not be modeled in the GIS system. If that is the case, the circuit origin location will be adequate.

Once the initial data request has been fulfilled and processed successfully ICF, with input from each utility participating, will identify high value feeders for more in-depth load flow analysis. ICF will request a distribution model, such as CYME, Synergi, or Windmil for that feeder's peak load. These high value feeders will be used to assess the accuracy of the methodology as well as make refinements.

Transformers:
- Transformer ID
- Feeder/ Circuit ID
- Size kVA
- Phase
- # of customers
- Customer type (residential, commercial, or mixed)
- Latitude/Longitude

Conductors:
- Conductor size
- Conductor capacity (preferred but not required)
- Phase
- Feeder/ Circuit ID
- Latitude (segment start/end)
- Longitude (segment start/end)

Substations and Circuits:
- Substation ID
- Substation transformer ID
- Substation transformer capacity (mVA)
- Connected circuit(s) ID
- Latitude/Longitude

Distributed Energy Resource (DER) (if available)
- DER and Circuit ID
- Voltage
- Inverter size
- Type (solar, BESS, combo, etc)

Reclosers
- Recloser ID
- Voltage
- Circuit ID
- Status (open/closed)
- Latitude/Longitude

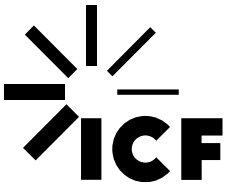
Switches:
- Switch ID
- Voltage
- Phase
- Circuit ID
- Status (open/closed)
- Latitude/Longitude
- Type: (UG, PTS, Multi-way, etc)

Voltage regulators:
- Regulator ID
- Regulator size
- Voltage
- Phase
- Feeder/ Circuit ID
- Latitude/Longitude

Capacitors:
- Capacitor ID
- Capacitor size
- Voltage
- Phase
- Feeder/ Circuit ID
- Latitude/Longitude

Transmission (if applicable)
- Conductor size
- Feeder/Circuit ID
- Latitude (segment start/end)
- Longitude (segment start/end)

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