

# An Assessment of Electrification Impacts on the Pepco DC Distribution System

## VOLUME II: TECHNICAL APPENDIX

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## NOTICE

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# I. Introduction

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This study assessed the capacity expansion investments needed for Pepco’s distribution grid to support full electrification, in line with the District’s climate goals and roadmap through 2040. We describe the findings of the study in our Volume I: Summary Report. This Volume II: Technical Appendix provides further detail on the modeling approach and assumptions underlying the analysis.

The focus of the study is load growth-driven distribution system capacity expansion investments. We evaluated the incremental grid upgrade requirements at the feeder and substation level in a full electrification scenario relative to a scenario with no additional electrification. The full electrification scenario assumes a pathway toward achievement of the District’s decarbonization goals and strategies, as enacted in the Climate Commitment Amendment Act of 2022<sup>1</sup> and further enumerated in the Carbon Free DC and Clean Energy DC Roadmaps.<sup>2</sup> The District’s strategies include both measures that would increase electricity demand (e.g., electrification of buildings and transportation) and measures that would moderate electricity demand (e.g., more stringent building codes and more rooftop solar generation).

We estimated the potential for energy efficiency, demand flexibility, and distributed energy resources—collectively referred to as “grid flexibility technologies”—to defer some of the required grid upgrades. Grid flexibility is defined as the ability to shift demand or supply to meet grid needs. Our estimates consider a range of future flexibility technology adoption rates based on observed participation rates in programs across the US. Important barriers currently prohibiting full-scale deployment and use of grid flexibility will need to be addressed for the higher potential estimates in our study to be achieved.

The following sections summarize our modeling methodology and input assumptions. Section II contains the scenario descriptions and detailed assumptions, Section III provides an overview of the electricity demand modeling methodology, Section IV describes how we modeled grid

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<sup>1</sup> [D.C. Law 24-176. Climate Commitment Amendment Act of 2022.](#)

<sup>2</sup> [Carbon Free DC 2045 Strategy](#) and [Clean Energy DC](#)

needs and solutions, and Section V describes how we modeled grid flexibility technologies and deferral potential.

## II. Scenario Framework and Assumptions

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This section describes the three study scenarios and assumptions regarding electrified equipment penetration, equipment efficiencies, end-use service demand, and fuel consumption in each scenario.

### A. Scenario Framework

The framework for this study consists of three scenarios for the Pepco DC system in 2040. The framework is intended to demonstrate the incremental demand impacts of electrification, followed by the mitigating impacts of grid flexibility technologies. The three scenarios are described below.

#### **Scenario 1: No Additional Electrification, No Additional Grid Flexibility**

This scenario holds the current (i.e., 2024) fuel mix for transportation and buildings constant through 2040 and assumes no additional distributed energy resources (DERs), energy efficiency, or demand flexibility. The purpose of the scenario is to serve as the status quo baseline relative to which impacts of electrification and grid flexibility can be evaluated. Load growth in this scenario is driven primarily by the forecasted load and customer count growth in Pepco's Ten-Year Forecast (TYF).

#### **Scenario 2: Full Electrification, No Additional Grid Flexibility**

This scenario assumes a 2040 fuel mix for transportation and buildings consistent with the electrification strategies enumerated in various District's climate initiatives. Apart from the additional electrification, this scenario preserves the other aspects of Scenario 1, including Pepco's forecasted growth of non-electrification loads. The purpose of this scenario is to allow estimation of grid needs to support the District's electrification goals in the absence of grid flexibility, and to serve as the basis for evaluating the potential value of grid flexibility to the distribution grid.

### Scenario 3: Full Electrification, Achievable Grid Flexibility

This scenario builds on Scenario 2 by assuming plausible levels of deployment of grid flexibility technologies—i.e., DERs, energy efficiency, and demand flexibility—by 2040. The purpose of this scenario is to demonstrate the potential value of mitigating grid needs using grid flexibility technologies and to highlight the relative contributions of different technologies. Three different deployment levels—Low, Mid, and High—are modeled in this scenario to reflect the uncertainty in customer adoption rates and in the development of the technical, commercial, and regulatory mechanisms needed to enable the use of these technologies to serve distribution grid needs.

None of the scenarios are intended to be bottom-up forecasts of technology adoption or load growth based on historical trends or technology economics. They are scenarios designed based on policy-driven assumptions about 2040, intended to enable the study of grid upgrade costs and the role of grid flexibility in a full electrification scenario per the Commission’s directive.

## B. Pepco Customer Count Assumptions

Table 1 shows the system-level customer counts provided by Pepco for 2024 and 2040. Additionally, Pepco provided customer counts for each substation and feeder in 2024. We used the system-level residential and commercial compound annual growth rates (CAGRs) to scale existing customer counts at the substation and feeder levels.

TABLE 1: CUSTOMER COUNTS IN 2024 AND 2040—ALL SCENARIOS

	2024	2040	Annual CAGR
Residential	317,842	469,960	2.47% (+48%)
Commercial	28,029	28,936	0.20% (+3.2%)

## C. Building Sector Assumptions

Space and water heating comprise a large share of building energy needs and are the primary end-uses that are targeted for electrification in the District’s climate initiatives related to the building sector. We first characterized the existing fuel mix and technologies that serve these end-uses in the District today and then developed assumed penetration levels for electrified technologies in 2040 based on District policies. To develop assumptions on the service demand, (i.e., the useful output energy) needed for these end-uses, we calibrated to the fuel consumed for each end use in 2024 and then assumed efficiencies for each technology to estimate the

useful output energy. This service demand per customer is assumed to remain unchanged through 2040 regardless of which equipment type the customer uses. For example, the average residential customer is assumed to require the same amount of useful heat in 2040 as they did in 2024. We also developed efficiency assumptions for each technology based on today's standards and forecasts, to enable estimate of electricity demand in 2040.

## 1. Equipment Types and Penetration

In the Full Electrification scenarios, we made the following assumptions on electrified space heating and water heating stock in 2040:

- **Electrified Equipment Penetration:** 90% of stock is heat pumps for both space heating and water heating to align with the Climate DC roadmap initiative for 90% of all homes and buildings to be fossil fuel free by 2040. All customers who used electric resistance heating in 2024 are also converted to using heat pumps by 2040 to align with the recommendations in the Clean Energy DC Plan on phasing out resistance heat.<sup>3</sup> We assumed ground source heat pumps comprise of 1% of the heat pump stock, and the other 99% is air source heat pumps with auxiliary resistive heating.
- **Non-electrified Portion:** The 10% of buildings not converted to electric heat pumps are assumed to be natural gas customers or buildings that use the district heating system. All district heating customers are assumed to remain on district heat and are included in the 10% of stock that is not electrified.

Table 2 summarizes the equipment penetration and count for 2024 and 2040 in each scenario. Throughout this report, we use “penetration” to refer to a percentage of total installed stock.

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<sup>3</sup> [Clean Energy DC](#)

**TABLE 2: 2024 AND 2040 EQUIPMENT PENETRATION (%) AND EQUIPMENT COUNT ('000 BUILDINGS)**

		Residential			Commercial		
		2024	2040 No Electrification	2040 Electrification	2024	2040 No Electrification	2040 Electrification
Space Heating	Natural Gas	178 (56%)	255 (56%)	44.9 (10%)	7.7 (26%)	8.8 (26%)	2.9 (8%)
	Fuel Oil	4.9 (2%)	7.0 (2%)	-	1.8 (6%)	2.0 (6%)	-
	Electric Resistance	82.6 (26%)	118 (26%)	-	8.6 (29%)	9.9 (29%)	-
	ASHP	48.0 (15%)	68.8 (15%)	40.0 (87%)	6.5 (22%)	7.5 (22%)	30.9 (89%)
	GSHP	-	-	0.4 (1%)	-	-	0.3 (1%)
	Other	-	-	-	5.0 (17%)	5.8 (17%)	-
	District Heat	-	-	-	0.27 (1%)	0.32 (1%)	0.3 (1%)
	No Heating	6.4 (2%)	9.2 (2%)	9.2 (2%)	0.21 (1%)	0.25 (1%)	0.3 (1%)
Water Heating	Natural Gas	148.3 (46%)	212.7 (46%)	45.8 (10%)	7.3 (26%)	8.9 (26%)	3.0 (9%)
	Fuel Oil	3.0 (1%)	4.3 (1%)	-	0.1 (0%)	0.1 (0%)	-
	Electric Resistance	167.7 (52%)	240.3 (52%)	-	21.7 (73%)	25.2 (73%)	-
	Heat Pump	-	-	412.6 (90%)	-	-	31.2 (90%)
	Other	-	-	-	-	-	-
	District Heat	-	-	-	0.05 (0%)	0.05 (0%)	0.06 (0%)
	No Heating	-	-	-	0.35 (1%)	0.41 (1%)	0.41 (1%)

Sources: Existing space heating and water heating stock penetration and energy usage estimated using EIA’s Residential Energy Consumption Survey ([RECS](#)) and Commercial Building Energy Consumption Survey ([CBECS](#))

## 2. Equipment Efficiencies

Table 3 summarizes our assumed coefficients of performance (COP) for each equipment type.

TABLE 3: EQUIPMENT COP ASSUMPTIONS

		Residential		Commercial	
		2024	2040	2024	2040
Space Heating	Natural Gas	0.80	0.95	0.85	0.85
	Fuel Oil	0.83	0.85	0.85	0.87
	Electric Resistance	0.98	1.00	1.00	1.00
	ASHP	Varies based on temperature. See Figure 1.			
	GSHP	3.60	3.60	3.50	3.50
Water Heating	Natural Gas	0.61	0.61	0.82	0.95
	Fuel Oil	0.64	0.66	0.81	0.81
	Electric Resistance	0.92	0.92	0.98	0.98
	Heat Pump	3.33	3.33	3.90	3.90

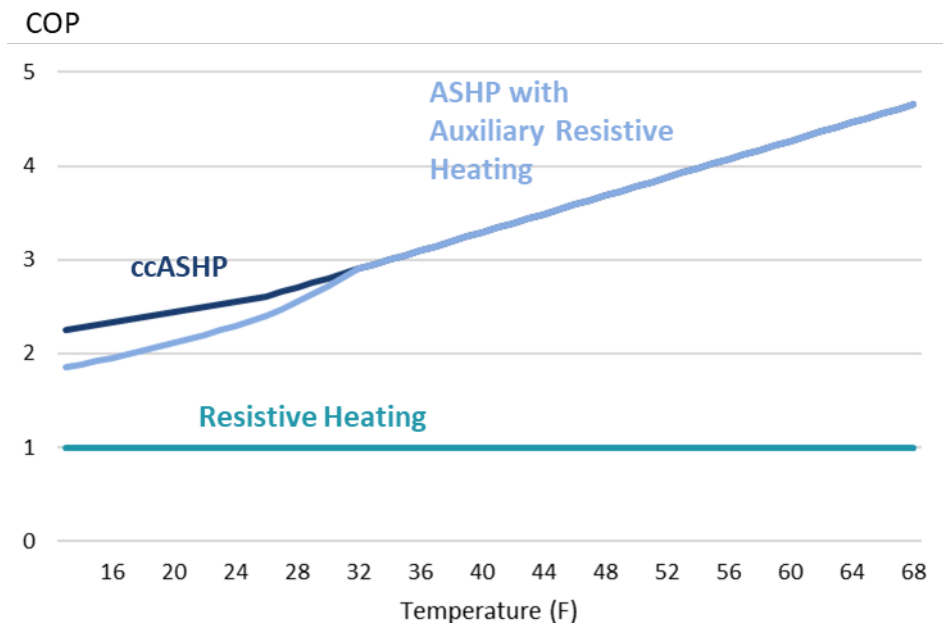
Sources: The 2024 and 2040 assumptions are based on the EIA Residential and Commercial Building Technologies Reference Case<sup>4</sup>.

ASHP COPs, as shown in Figure 1, are modeled based on a temperature-COP curve. The COP varies in each hour based on the outdoor temperature in that hour in the modeled weather year. The auxiliary resistive heating is assumed to begin operating at temperatures below 32°F to supplement the heat pump. As the temperature gets colder, the overall COP of the system (ASHP + resistive heat) worsens as the resistive heating supplies a greater portion of the output. In the Full Electrification with Grid Flexibility scenario, we model deployment of cold-climate air source heat pumps (ccASHPs) in lieu of a portion of the ASHPs. The ccASHPs are modeled as

<sup>4</sup> [EIA Residential and Commercial Building Technologies Reference Case](#)

being sized to meet the full heating load without resistive backup, and therefore, their COPs are slightly higher at lower temperatures.

FIGURE 1: ASHP COP CURVE



Source: The heat pump COP-temperature curve is from Gibb, et al., [Coming in from the cold: Heat Pump efficiency at low temperatures](#). We estimate the curve for ASHPs with auxiliary resistive heating by blending the resistive heating COP of 1 at temperatures below 32F.

Due to uncertainty around federal standards for appliance efficiency, we do not assume efficiency improvements for the installed stock of heat pumps by 2040.

### 3. Fuel Consumption and Service Demand

We calibrated to the 2024 fuel consumption by technology type based on per customer estimates in EIA’s Residential Energy Consumption Survey (RECS) and Commercial Energy Consumption Survey (CBECS), multiplied by customer counts in the District. We benchmarked the resulting electricity and natural gas consumption estimates against historically reported utility sales to confirm the accuracy of the baselines and make District-specific adjustments where needed.

We used the fuel consumption assumptions, in conjunction with assumed equipment efficiencies, to develop estimates of service demand, i.e., the demand for end-use energy for space and water heating. We assume service demand per customer remains the same as 2024 in 2040, with growth in overall service demand due to a growing customer count. Table 4 and

Table 5 summarize the resulting fuel consumption and service demand assumptions for the residential and commercial sectors.

**TABLE 4: RESIDENTIAL FUEL CONSUMPTION AND SERVICE DEMAND**

		Fuel Consumption (000 MMBtu)			Service Demand (000 MMBtu)		
		2024	2040 No Electrification	2040 Electrification	2024	2040 No Electrification	2040 Electrification
Space Heating	Natural Gas	6,676	8,060	1,420	5,341	7,657	1,349
	Fuel Oil	55	76	-	45	65	-
	Electric Resistance	445	626	-	436	626	-
	ASHP	244	350	2,416	818	1,173	8,090
	GSHP	-	-	23	-	-	82
	Other	-	-	-	-	-	-
	District Heat	-	-	-	-	-	-
	No Heating	-	-	-	-	-	-
Water Heating	Natural Gas	3,249	4,658	1,004	1,982	2,841	612
	Fuel Oil	38	83	-	38	55	-
	Electric Resistance	1,254	1,798	-	1,154	1,654	-
	Heat Pump	-	-	1,182	-	-	3,937
	Other	-	-	-	-	-	-
	District Heat	-	-	-	-	-	-
	No Heating	-	-	-	-	-	-

TABLE 5: COMMERCIAL FUEL CONSUMPTION AND SERVICE DEMAND

		Fuel Consumption (000 MMBtu)			Service Demand (000 MMBtu)		
		2024	2040 No Electrification	2040 Electrification	2024	2040 No Electrification	2040 Electrification
Space Heating	Natural Gas	7,101	8,211	2,698	6,036	6,979	2,293
	Fuel Oil	483	545	-	410	474	-
	Electric Resistance	1,088	1,258	-	1,088	1,258	-
	ASHP	180	208	2,452	605	700	8,258
	GSHP	-	-	24	-	-	83
	Other	1,244	1,439	-	1,058	1,223	-
	District Heat	199	231	231	169	196	196
	No Heating	-	-	-	-	-	-
Water Heating	Natural Gas	1,069	1,067	358	877	1,014	340
	Fuel Oil	13	15	-	11	12	-
	Electric Resistance	558	645	-	546	632	-
	Heat Pump	-	-	338	-	-	1,318
	Other	-	-	-	-	-	-
	District Heat	33	33	33	27	32	32
	No Heating	-	-	-	-	-	-

## D. Transportation Sector Assumptions

Electrification of light-, medium-, and heavy-duty vehicles (LDVs, MDVs, and HDVs) is a key part of the District's climate initiatives. We developed 2040 electrified LDV assumptions based on the EV sales targets set in the Advanced Clean Cars Act.<sup>5</sup> Sale targets increase from around 20% today to 100% by 2035. Our MDV and bus electrification assumptions are based on the Clean Energy DC Omnibus Amendment Act requirement that all public buses and privately operated fleets must be low-or-zero emission vehicles.<sup>6</sup> Finally, we developed the electric HDV penetration based on the target for residual emissions from diesel in the Clean Energy DC roadmap, assuming that most residual diesel consumption is for non-electrified HDVs.

The following tables summarize our assumptions on vehicle counts, efficiencies, average annual mileage per vehicle, and total fuel demand.

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<sup>5</sup> [DC Adoption of Advanced Clean Car Act.](#)

<sup>6</sup> [Clean Energy DC Omnibus Amendment Act](#)

**TABLE 6: 2024 AND 2040 PENETRATION (%) AND EQUIPMENT COUNT ('000 VEHICLES)**

		Vehicle Count		
		2024	2040 No Electrification	2040 Electrification
Light-Duty Vehicle Usage	ICE	298,290 (92%)	306,451 (92%)	91,639 (27%)
	EV	8,100 (2%)	8,322 (2%)	245,530 (73%)
	HEV	18,100 (6%)	18,595 (6%)	-
	PHEV	3,700 (1%)	3,801 (1%)	-
Medium-Duty Vehicle Usage	ICE	3,357 (100%)	3,449 (100%)	690 (20%)
	EV	-	-	2,759 (80%)
Heavy-Duty Vehicle Usage	ICE	480 (100%)	493 (100%)	443 (90%)
	EV	-	-	49 (10%)
Bus Usage	ICE	7,573 (92%)	7,780 (92%)	848 (10%)
	EV	38 (0.5%)	39 (0.5%)	7,636 (90%)
	HEV	648 (7.5%)	666 (7.5%)	-

Source: 2024 vehicle counts estimated using Alternative Fuels Data Center<sup>7</sup> and VIUS Census Data.<sup>8</sup> Abbreviations: Internal combustion engine (ICE), battery electric vehicles (EVs), hybrid EVs (HEVs), plug-in hybrid EVs (PHEVs).

<sup>7</sup> [Alternative Fuels Data Center: Vehicle Registration Counts by State](#)

<sup>8</sup> [VIUS211A: All Vehicles by ... - Census Bureau Table](#)

TABLE 7: 2024 AND 2040 ANNUAL MILEAGE AND VEHICLE EFFICIENCIES

		Annual Mileage (millions of miles)			Efficiencies	
		2024	2040 No Electrification	2040 Electrification	2024	2040
Light-Duty Vehicle Usage	ICE	2,985	3,200	957	38 mpg	45 mpg
	EV	81	87	2,564	3.28 mi/kWh	4.1 mi/kWh
	HEV	181	194	-	1.78 mi/kWh	1.8 mi/kWh
	PHEV	37	40	-	3.86 mi/kWh	4.8 mi/kWh
Medium-Duty Vehicle Usage	ICE	35	38	8	9 mpg	11 mpg
	EV	-	-	31	0.72 mi/kWh	0.97 mi/kWh
Heavy-Duty Vehicle Usage	ICE	25	28	25	6.5 mpg	7.8 mpg
	EV	-	-	3	0.42 mi/kWh	0.45 mi/kWh
Bus Usage	ICE	125	135	15	5.3 mpg	5.3 mpg
	EV	1	1	133	0.47 mi/kWh	0.47 mi/kWh
	HEV	11	12	-	0.19 mi/kWh	0.19 mi/kWh

Source: Vehicle efficiencies and average VMTs from EV Database,<sup>9</sup> EIA,<sup>10</sup> and Federal Highway Administration.<sup>11</sup>

<sup>9</sup> [Energy consumption of full electric vehicles cheatsheet - EV Database](#); PHEV electric efficiency is assumed to be EV multiplied by ratio of average PHEV to EV efficiency.

<sup>10</sup> [U.S. Energy Information Administration - EIA - Independent Statistics and Analysis](#)

<sup>11</sup> [Table MV-1 - Highway Statistics 2023 - Policy | Federal Highway Administration](#)

TABLE 8: 2024 AND 2040 FUEL CONSUMPTION

		Fuel Consumption (GWh or million gallons)		
		2024	2040 No Electrification	2040 Electrification
Light-Duty Vehicle Usage	ICE (000,000 gallons)	78.5	71.6	21.4
	EV (GWh)	25	21	627
	HEV (GWh)	102	110	-
	PHEV (GWh)	10	8	-
Medium-Duty Vehicle Usage	ICE (000,000 gallons)	3.9	3.6	0.73
	EV (GWh)	-	-	32
Heavy-Duty Vehicle Usage	ICE (000,000 gallons)	3.9	3.6	3.3
	EV (GWh)	-	-	6
Bus Usage	ICE (gallons)	23.6	25.5	2.8
	EV (GWh)	1	1	281
	HEV (GWh)	57	62	-

Source: Based on stock, efficiencies, and annual mileage from above tables

### III. Electricity Demand Modeling

This section describes our approach to modeling hourly load in 2040 at the feeder and substation level. The approach consisted of three steps:

- Gather and clean 2024 historical hourly load for each feeder and substation provided by Pepco

- Disaggregate 2024 load into electrification and non-electrification loads and grow baseline loads based on Pepco’s feeder-specific load forecast through 2040
- Add on electrification loads in 2040 based on the assumed technology penetration levels in the scenario and hourly load shapes for each electrified technology

The sub-sections below describe each of these steps in further detail.

## A. Baseline Year

We selected 2024 as the baseline year for the study, used as the source for the baseline hourly load shape and as the baseline weather year, which influences heating needs and COPs.

Peak load varies from year to year, partly due to the maximum summer and minimum winter temperatures. More extreme temperatures generally result in higher peak loads. Pepco’s normal planning process uses a 90/10 year, which corresponds to a minimum temperature of 10°F and a maximum temperature of 101°F.<sup>12</sup> 2024 corresponded reasonably closely to various 90/10 year metrics. The winter minimum temperature in 2024 was 16°F, and the summer maximum temperature was 103°F.<sup>13</sup>

In addition, using 2024 ensures that we use the most recent available full year of data, which captures impacts of customer growth, changes in behavior, deployment of energy efficiency and DERs, and various other dynamics.

## B. Feeder and Substation Data

Using Pepco’s Ten-Year Forecast and other supplemental data, we collect the following information on each feeder and substation to inform our 2040 load growth estimates:

- **Pepco 2025–2034 Ten-Year Plan:** For each feeder and substation, the 2024 peak load, the 2034 planned peak load, rated capacity, and any load transfers that are planned out to 2034.
- **2024 Hourly Load:** Actual 2024 substation and feeder level hourly load.

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<sup>12</sup> Over the last 30 years, the maximum annual temperature was 101°F in the 90<sup>th</sup> percentile year (August 3, 2006), and the minimum annual temperature was 10°F in the 90<sup>th</sup> percentile year (February 6, 1996).

<sup>13</sup> Temperature data reported from Reagan National Airport (DCA) weather station.

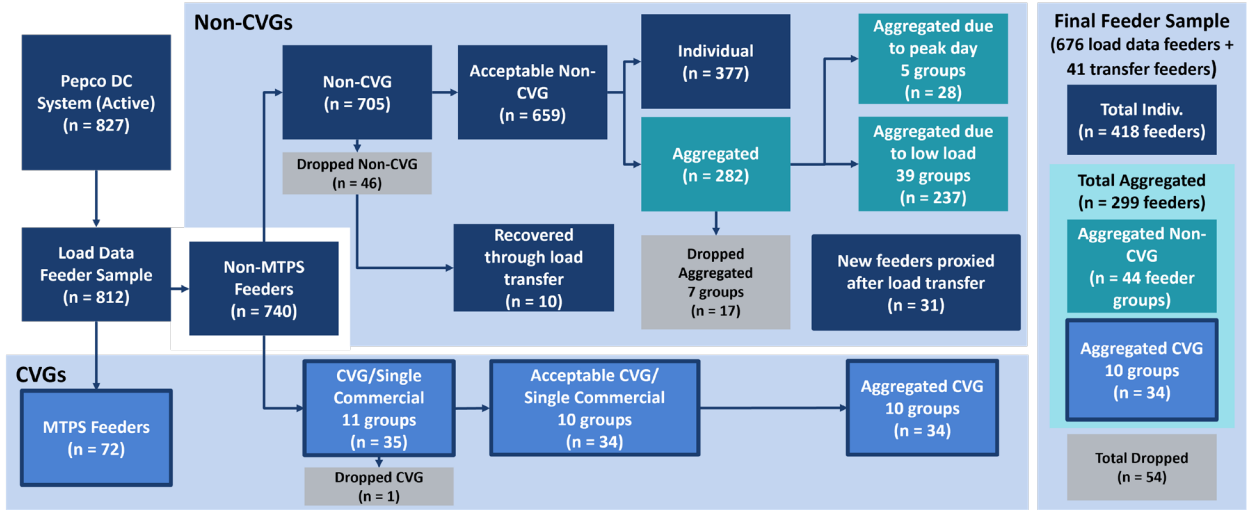
- **2024 Customer Counts:** 2024 residential and commercial customer counts for each feeder and substation.

# 1. Cleaning Feeder and Substation Load Data

## a. Feeder Data

Figure 2 describes our treatment of the hourly feeder load data for Pepco DC’s system. Because most of the data was complete, our approach was to eliminate the few feeders with insufficient data from the study. In addition, due to the complexity of load transfers occurring between neighboring feeders within the baseline-year period, we developed a set of data completeness criteria to identify feeders that were more accurately characterized by the aggregated hourly load of the whole feeder group. We modeled the 299 feeders identified through this process as 44 feeder groups, rather than as individual feeders in order to reflect the ability to frequently shift load between the feeders. We modeled the other 418 feeders as individual feeders, and we dropped a total of 54 feeders due to insufficient data.

FIGURE 2: FEEDER DATA CLEANING PROCESS



The data cleaning process consisted of the following steps:

1. We received 2024 hourly load for 812 of 827 feeders in operation in 2024. The 15 feeders we did not receive data for were feeders that do not have SCADA systems and, therefore, do not have hourly load data readily available.
2. We preserved the 72 feeders that serve DC Metro stations, labeled Metro Traction Power System (MTPS) feeders, as-is through 2040, with only Pepco-forecasted load growth in all scenarios.

3. We subset the remaining 740 non-MTPS feeders into our primary feeder sample (705) and Common Voltage Group (CVG) feeders (35), typically pairs of feeders serving single commercial customers. We aggregated hourly loads for individual CVG feeders up to the feeder group level to form 11 CVG feeder groups, with 10 CVG groups meeting our data sufficiency criteria, described in the next step, to be modeled in our sample.
4. We processed the hourly load data for 705 feeders individually for completeness. Individual hourly feeder data that met one of the criteria below was dropped from the sample if there were no customers assigned to the feeder and aggregated to the feeder group level if there were customers assigned to the feeder. We used the following thresholds to check for data sufficiency:
  - Average hourly load less than 0.05 MW in 2024
  - One or more sets of consecutive null values of more than three weeks (504 hours)
  - Any null values during winter and summer system peak days in 202428 feeders were dropped due to these filters.
5. We aggregated feeder groups containing a flagged feeder with active customer counts and retested the feeder group hourly load for completeness. We dropped 7 groups from the sample. The remaining 44 aggregated groups (containing 299 individual feeders) and 377 individual feeders made up the active 2024 feeders used in our modeling sample.
6. An additional 41 feeders are added to the sample by way of load transfers and already-planned new asset builds through 2034, in accordance with Pepco's plan.

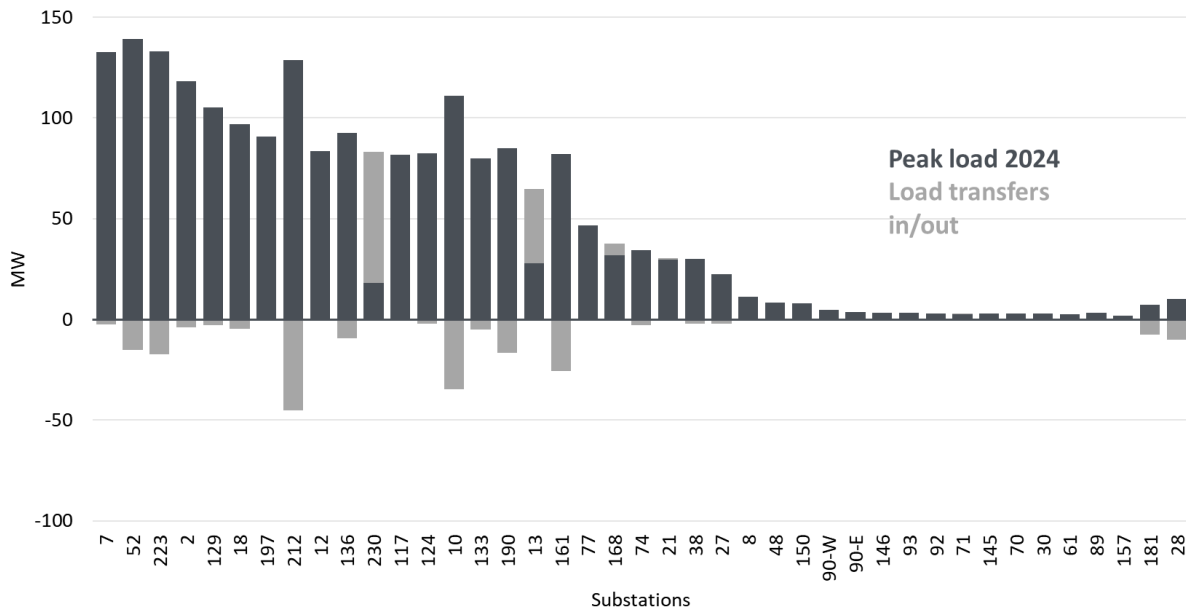
## **b. Substation Data**

We received hourly 2024 load data for 41 of 45 substations. The four substations not included in the study were 4kV primary network substations with a combined contribution to system peak of less than 1%. Our 2040 sample contained 38 substations and incorporated the planned decommissioning of three substations per Pepco's TYF.

## **c. Load Transfers**

Before forecasting load data into the future, we first initiate all feeder and substation load transfers identified in Pepco's TFY so that usage shapes are preserved. For example, a feeder or substation that gets 50% of its load transferred out has its load shape preserved, and the feeder/substation that receives the transfer has the exact load shape transferred onto it. Figure 3 shows substation peaks after load transfers. We apply a similar step for feeder loads.

**FIGURE 3: PLANNED SUBSTATION LOAD TRANSFERS RELATIVE TO 2024 PEAK LOAD**



## 2. Forecast of Non-Electrification Load Growth

To avoid double-counting electrification loads, we first disaggregate the 2024 load into electric space and water heating and transportation loads (collectively referred to as electrification loads) and other loads (non-electrification loads). Because feeder-specific heating/transportation equipment saturations were not available, for the purposes of disaggregation, we assume that the residential and commercial technology penetration on each feeder is equal to the Pepco system average penetration (provided in Section II). This allowed us to disaggregate the 2024 load into four primary components: residential baseline load, residential electrified load, commercial baseline load, and commercial electrified load.

By disaggregating and isolating the baseline load in 2024 from any electrification load, we were able to scale baseline residential and commercial load components at their respective, distinct growth rates from Pepco’s feeder-specific load forecast. We modeled 2034 load for each distribution asset such that each load shape reflected the peak load growth forecasted in Pepco’s TYF. Because Pepco’s TYF ends in 2034, we used customer count growth through 2040 to extrapolate the non-electrification load growth on each asset through 2040.

### 3. Modeling Electrification Loads

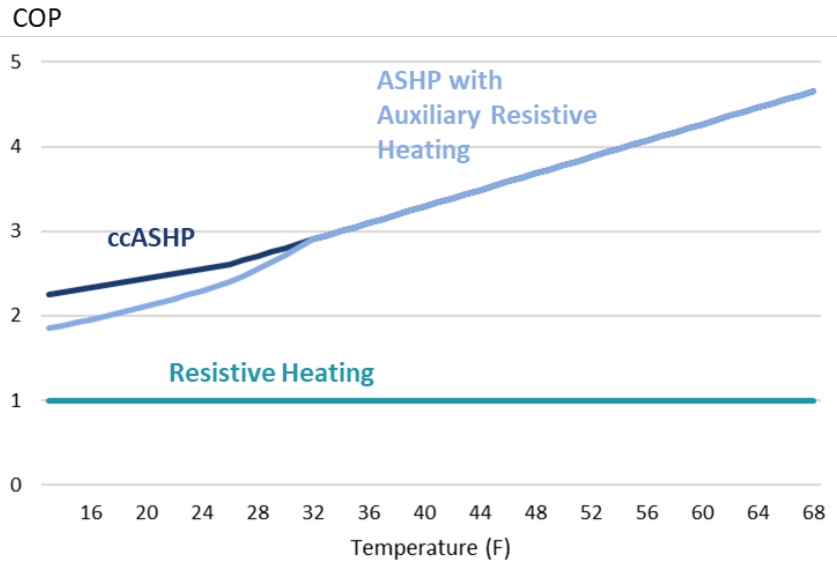
Electrification load on each feeder is modeled based on the count of electrified space and water heating equipment and vehicles on each feeder, combined with an assumed hourly load shape for each electrified end use.

The count of electrified equipment on each feeder is developed based on the residential and commercial customer counts and the system-wide average equipment penetration for each type of equipment. We do not attempt to develop a feeder-specific allocation of equipment because at high penetration levels approaching 100%, all locations begin to converge to similar penetration levels. Therefore, we assume for example, that if 90% of residential customers in the District have heat pumps, 90% of residential customers on every feeder have heat pumps. LDVs are allocated based on residential customer count, and MHDVs are allocated based on commercial customer count. There is a significant amount of feeder-level load shape variation in this study due to the use of actual 2024 data as the baseline, and allocation of electrified loads based on the feeder-specific proportion of residential and commercial customers.

We model hourly electrification load based on assumed hourly load shapes for each type of equipment. These load shapes and their sources are provided in Figures 4–6 below.

**Space Heating:** The space heating load shape varies across the 8,760 hours of the year based on hourly temperature in the 2024 weather year. We develop hourly heating demand based on an allocation of annual heating service demand to each hour of the year proportional to the share of annual heating degree days (HDDs) on each day. Electric resistance and GSHP load scales linearly with HDDs. ASHPs are modeled on a more granular level as they get less efficient the colder it gets. Further, we assume that some share of ASHP heating load is served by electric resistance backup during any hour in which the temperature drops below freezing. The ASHP COP efficiency curve is shown in Figure 4. We look up the ASHP COP in each hour of the 2024 weather year to dynamically model the associated heating load.

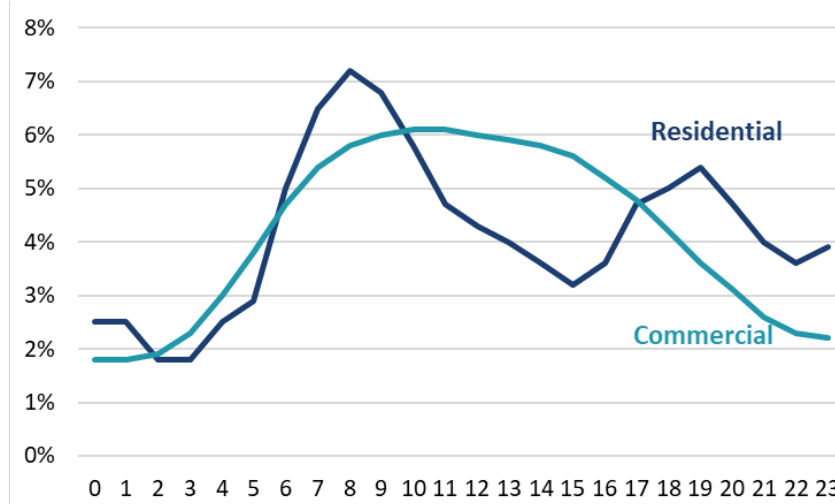
FIGURE 4: ASHP COP CURVE



Source: The heat pump COP-temperature curve is from Gibb, et al., [Coming in from the cold: Heat Pump efficiency at low temperatures](#). We estimate the curve for ASHPs with auxiliary resistive heating by blending the resistive heating COP of 1 at temperatures below 32°F.

**Water Heating:** Water heating load is modeled using the daily shape in Figure 5.

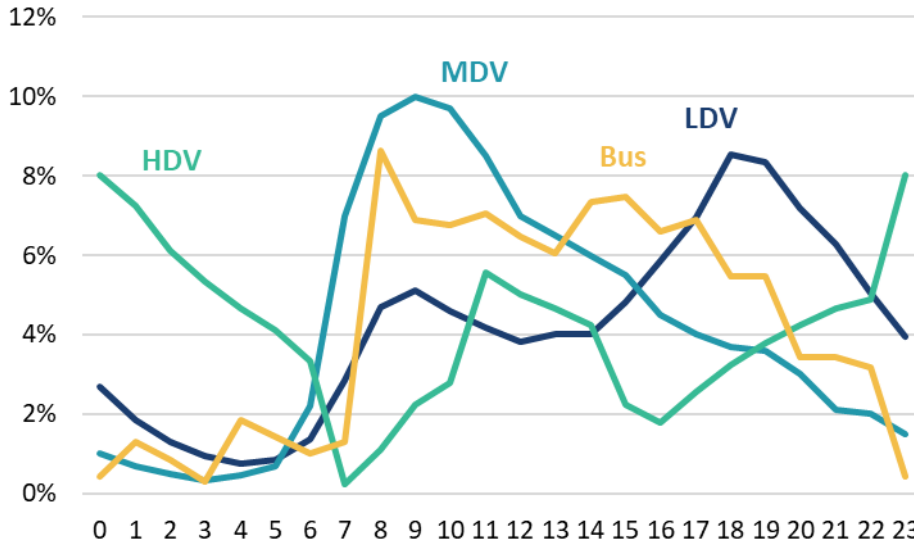
FIGURE 5: WATER HEATING LOAD SHAPE (SHARE OF DAILY LOAD %)



Source: [EPRI Load Shape Library](#)

**EV Charging:** LDV, MDV, HDV, and bus charging loads are modeled using the hourly shapes in Figure 6.

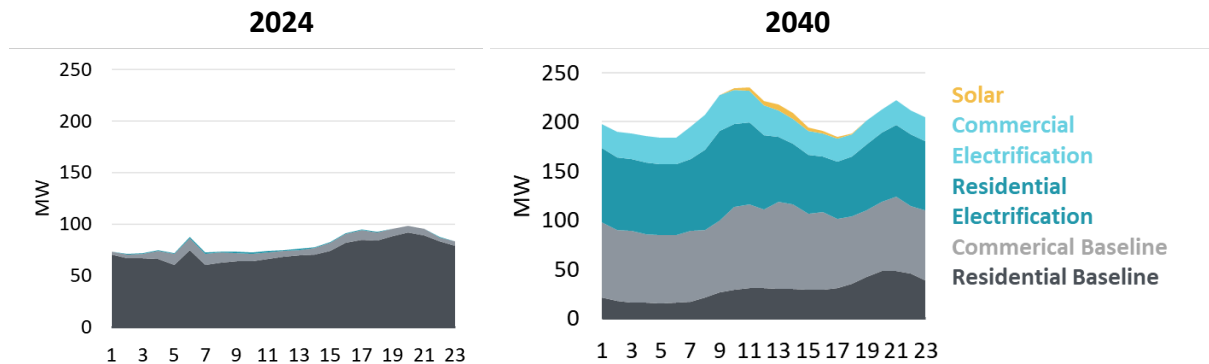
**FIGURE 6: DAILY EV CHARGING SHAPE (SHARE OF DAILY LOAD %)**



Source: LDV shape from EVI Pro-Lite. MDV from commercial LDV load shape in the [California Load Shapes Report](#). HDV and bus from tractor trailer and school bus load shape respectively in [2021 California Report](#)

The outcome of the asset-specific load modeling process in the Full Electrification scenario is illustrated in Figure 7 for one example substation’s peak day.

**FIGURE 7: 2024 AND 2040 PEAK DAY LOAD IN THE FULL ELECTRIFICATION, NO ADDITIONAL GRID FLEXIBILITY SCENARIO FOR SUBSTATION 7)**



Notes: In 2024, Substation 7 is a summer peaking asset with the highest observed load on July 15, 2024 at 7PM. In 2040, Substation 7 is a winter peaking asset with the highest observed load on January 17, 2040 at 9AM.

## IV. Grid Needs and Solutions Modeling

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This section describes our methodology for modeling the grid upgrades that would be needed in overloaded locations, and the cost assumptions we received from Pepco for each type of capacity expansion project.

### A. Capacity Expansion Solutions and Cost Assumptions

Pepco provided cost estimates based on recent representative projects for each type of capacity expansion solution. The set of solutions includes new feeder builds, feeder conversions, load transfers, building a new transformer bank at a substation, and building a new substation. Because not every type of capacity expansion project is possible at every asset, we developed rules of thumb to disallow certain solutions in some locations. For example, we do not allow addition of transformer banks to substations located in Wards 2 or 6 because these locations were flagged by Pepco as being unlikely to have the physical space for a new transformer. Table 9 summarizes the set of upgrades we used to model solutions to overloads at the feeder and substation level in each scenario.

TABLE 9: CAPACITY EXPANSION SOLUTION COSTS

Component	Upgrade Type	Description	Cost (2025\$)
Feeder	New 13kV Feeder	Construct new 13.8kV overhead feeder with summer normal rating of 8.5MVA <sup>14</sup>	\$11 million / mile
	4kV Overhead Feeder Conversion	Convert 4kV feeder to 13kV feeder. Transfer load out from 4kV substation	\$6.2 million
	Feeder Load Transfer	Transfer feeder overload MVA to a new 13kV feeder	Included in cost of new feeder construction
Substation	New Transformer Bank <i>(Available for select &lt;100 MVA Substations)</i>	Install new transformer at substation with available bank space. Increase firm capacity to 144 MVA	\$8 million
	New Transformer Bank <i>(Available for &lt;165 MVA Substations)</i>	Install new transformer at substation with available bank space. Increase firm capacity to 210 MVA	\$8 million
	New 210 MVA Substation	Construct new 210 MVA substation	\$294 million
	Substation Load Transfer	Transfer substation overload MVA to new 210 MVA substation	Included in cost of new substation construction

## B. Distribution Buildout Model Upgrade Criteria

In alignment with Pepco’s capacity planning criteria, we flag an asset as requiring a capacity expansion solution if its peak hourly load is greater than 100% of normal rated seasonal capacity<sup>15</sup> in any hour of the year in 2040.

<sup>14</sup> Per Pepco’s rule of thumb, we assign new 13kV feeders an average length of one mile to treat the construction of a new feeder as unit cost of \$11 million.

<sup>15</sup> Asset MVA ratings are higher in the winter due to colder conditions.

**Feeders.** For any 13kV feeder or aggregated feeder group with an identified winter or summer overload, new 13kV feeders with a normal rating of 8.5 MVA are constructed to meet overload capacity. If the overload on the feeder or group is greater than 8.5 MVA, the lowest possible number of new 8.5 MVA feeders are constructed to meet overload capacity, and the overload is distributed across newly constructed feeders. For any 4kV feeder or feeder group experiencing a winter or summer overload, a 4kV feeder is converted to a 13kV feeder and all load is transferred to the new 13kV feeder.

**Substations.** Prior to implementing the distribution buildout model, we identified the possible upgrade capabilities for all substations on the Pepco DC system. For substations with a capacity under 100 MVA, Pepco provided a comprehensive breakdown of maximum feasible capacity increases through additional transformer banks. For substations with capacity of 140–165 MVA, we assume an additional transformer bank can be added to increase firm capacity to 210 MVA. Existing substations located in Pepco DC Wards 2 and 6 are exceptions to this rule, as they do not have space for an additional transformer bank. This means overloads to substations in these two Wards must be resolved through construction of a new substation. An exception is made for Mt. Vernon Sub 230, a new substation energized in 2024 in Ward 6, because it was planned with room for an additional transformer bank.

For all substation overloads, our model selects the lowest-cost option that satisfies component- and Ward-specific feasibility requirements. For 5 of 10 overloaded substations on the Pepco DC system, the lowest cost option is to install an additional transformer bank to increase firm capacity to 210 MVA. For substations with an existing firm capacity of 210–216 MVA, new substations must be constructed to mitigate observed overloads. Overloaded substations serving 4kV overhead feeders are afforded the mitigation option of feeder conversion and load transfer out to a substation within the same Ward. This is the lowest-cost mitigation option when an existing or new substation is observed to have the available headroom. In these cases, a 4kV feeder served by the overloaded substation is converted to a 13kV feeder, connected to an existing or new substation in the same ward, and all feeder load is transferred to the converted 13kV feeder.

# V. Grid Flexibility Modeling

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## A. Overview

We considered a range of grid flexibility solutions that potentially could help reduce peak load and as a result defer peak demand-driven upgrades to the distribution system. The grid flexibility solutions considered in our study include DERs, energy efficiency, and demand flexibility measures.

As described in the Volume I report, there is significant potential for grid flexibility to defer upgrades to the distribution system. However, various conditions must be met for this outcome to be achieved. For example, the cost of enabling grid flexibility needs to be less than the cost of the distribution upgrade, grid flexibility measures need to be adopted at significant levels in a specific location of the grid to provide a sufficient magnitude of demand reduction, and the utility needs infrastructure that provides the necessary visibility and control to manage the grid flexibility resources. Regulatory, technical, and market barriers likely will need to be overcome for those conditions to be achieved.

Given the uncertainty in how grid flexibility opportunities may evolve on the Pepco DC system over our study horizon, we created an illustrative portfolio of grid flexibility resources and analyzed the portfolio's ability to defer distribution upgrades at various levels of adoption. The analysis is not intended to represent a comprehensive assessment of all possible grid flexibility measures. In other words, it is not a potential study. Rather, our study illustrates the technical ability of grid flexibility to impact distribution upgrade needs at various significant levels of deployment.

## B. Grid Flexibility Measures

Below, we describe how we modeled each grid flexibility option included in the portfolio.

**BTM solar.** The District has a requirement that 15% of annual energy demand be served from distributed solar by 2041.<sup>16</sup> Our analysis considered a scenario in which that level of deployment is met as well as two scenarios in which the target is not met. We assume each

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<sup>16</sup> [Local Solar Expansion Amendment Act of 2022](#)

substation or feeder's load is served by that same share of solar generation. Our assumed hourly solar generation profile is based on NREL's System Advisor Model (SAM) for a location in Pepco's service territory.<sup>17</sup> The hourly load profile is subtracted from each feeder or substation's load to establish the contribution of BTM solar to reducing local peak demand. We note that basing this analysis on the representative solar output profile for single year is a simplification and may overstate the contribution of standalone solar to distribution upgrade deferral, as solar output is variable across years and may not be attributed to distribution capacity value in certain planning contexts.

**Weatherization.** This measure refers to building envelope upgrades that reduce the building's heating demand, such as air sealing, attic insulation, duct sealing, and window upgrades. The reduction in heating demand is measured as a proportional decrease in demand for heating in all hours. We assume a 10% reduction in heating demand per building.<sup>18</sup> We use illustrative adoption assumptions of 20%, 10%, and 5% of all buildings in the District for the three grid flexibility scenarios. Weatherization is generally a valuable but more difficult energy efficiency option for customers to adopt, due to up-front costs and the inconvenience of installing the measures, among other factors.

**Cold climate heat pumps.** Whereas standard air source heat pumps often include auxiliary resistive heating for temperatures below 32°F, cold climate air-source heat pumps do not require resistive heating and therefore, are more efficient on the coldest days of the year that drive winter peak demand. As shown in Figure 4 above, we assumed cold climate ASHPs would have a coefficient of performance of 2.34 at 16°F (the coldest modeled hour), representing roughly a 20% improvement in efficiency relative to ASHPs with auxiliary resistive heating. We assumed illustrative cold climate heat pump adoption levels of 50%, 25%, and 12.5% of all heat pumps in the District across the three grid flexibility scenarios.

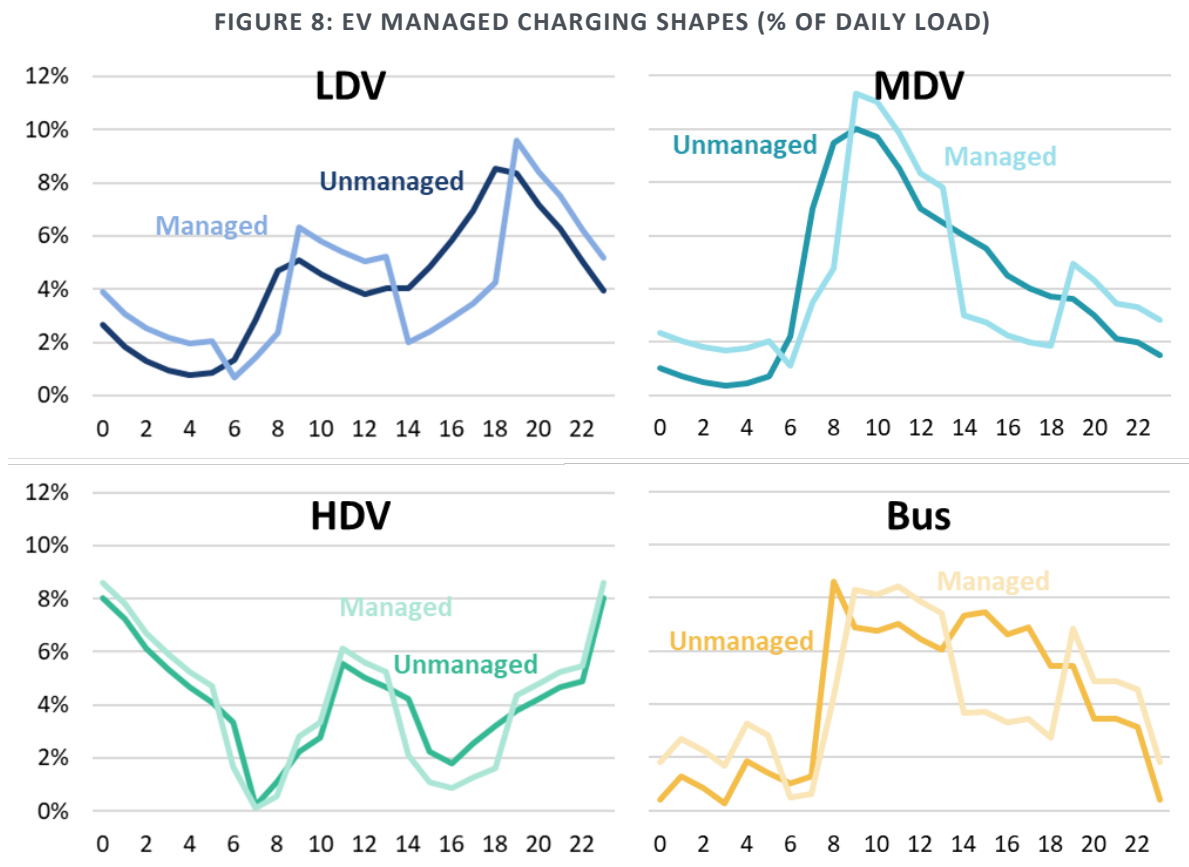
**EV managed charging.** This measure assumes that EV charging load will be shifted away from system peak load hours and into overnight hours with lower demand. That load shifting could be driven by response to a time-of-use rate or active control by the utility or an aggregator; our analysis is agnostic to the incentive mechanism or means of control. We make the simplifying assumption that the EV managed charging load profiles are static and designed to shift load away from the hours of the system peak. We assume 50% of charging load during the peak hours of 6am–9am and 2pm–7pm would be reduced and shifted to all other hours, based on a

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<sup>17</sup> [NREL SAM](#)

<sup>18</sup> Based on the energy savings ranges for the Weatherization Assistance Program reported in Oak Ridge National Lab's National Evaluations Summary Reports.

review of utility managed charging pilots across the US. Figure 8 below illustrates the assumed charging load profiles before and after load shifting.



**Heating load control.** While heat pump load control is still in the early stages of deployment, with technical barriers to be addressed, it has the potential to be an important grid flexibility option given that it targets the end use that is primarily driving winter peak demand. We assume participants in the heating load control program reduce between 20% and 40% of their heating load during a three-hour demand response event, with up to 15 events being called per year, based typical program event limits observed across various U.S. utility smart thermostat programs.<sup>19</sup> The curtailed load is entirely offset by two hours of pre-heating before the event and three hours of “snapback” after the event. The events are called to target each feeder or substation’s peak demand individually, after accounting for changes in load due to the other demand flexibility measures described above. We assume 25%, 12.5%, and 5% participation scenarios among customers with heat pumps. While heating load control is largely still in the

<sup>19</sup> [The State of Demand Flexibility Programs and Rates and Their Role in Managing Peak Demand](#)

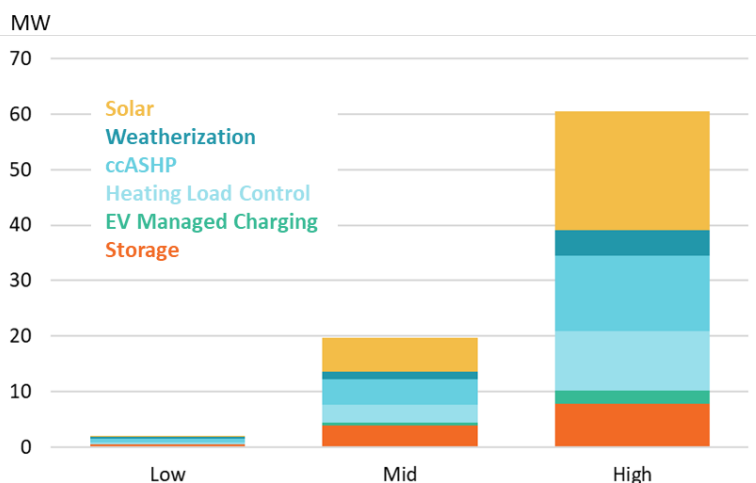
pilot phase, some utilities have achieved air-conditioning load control participation rates at the levels modeled in our scenarios.

**Batteries.** After accounting for the impacts of the grid flexibility measures described above, we identified any distribution assets that had remaining overloads that could be reasonably resolved with through deployment of distributed batteries. We assumed that a feeder or substation would need to satisfy the following illustrative conditions in order to be a candidate for deferral with distributed storage: (1) overloads of up to 2.5% in the low case, 5% in the mid case, and 10% in the high case, to ensure a feasible level of storage deployment relative to total load at the location; (2) less than four hours of overloading on any given day, to align with the likely duration of deployed batteries; and (3) fewer than 35 overloaded hours in the low/mid cases and 70 hours in the high case, to allow for value stacking in the wholesale market and otherwise limit dispatch events for batteries located behind the customer’s meter. Under those conditions, we dispatched storage to mitigate the overloads.

## C. Impacts

Based on the assumptions described above, each grid flexibility option makes a different contribution to relieve grid overloads. Figure 9 below summarizes the total megawatts of overload attributed to each grid flexibility option.<sup>20</sup>

**FIGURE 9: GRID FLEXIBILITY DEMAND REDUCTIONS THAT ELIMINATE OVERLOADS**



<sup>20</sup> We assigned savings value to each grid flexibility option based on the dispatched MWhs on days in which the option was utilized on an overloaded distribution asset. If there were additional savings beyond the rated capacity during that hour, the savings that contributed to the overload were allocated to each grid flexibility technology proportional to the total dispatch during the overloaded hours.