Electric Load Forecast

Highlights

- This Appendix presents forecasts for the number of retail customers, system energy and demand at time of peak for the Duke Energy Carolinas and Duke Energy Progress service territories.
- Details around Duke Energy's load forecast process are included in this Appendix, providing a foundation for many of the additional scenarios for load growth that appear elsewhere in the Carolinas Resource Plan.
- Major factors that affect the long-term outlook for energy demand in the Carolinas include economic growth, the growth of residential customers and the surge in electric vehicle-related demand.

The Carolinas Resource Plan (the "Plan" or "the Resource Plan") forecasts provide projections of the energy and peak demand needs for customers in Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP" and, together with DEC, "Duke Energy" or the "Companies") service areas. Only by recognizing the size of the need for energy, including the dynamics that will shape that evolving need during the years to come, can a prudent plan to meet those needs be developed.

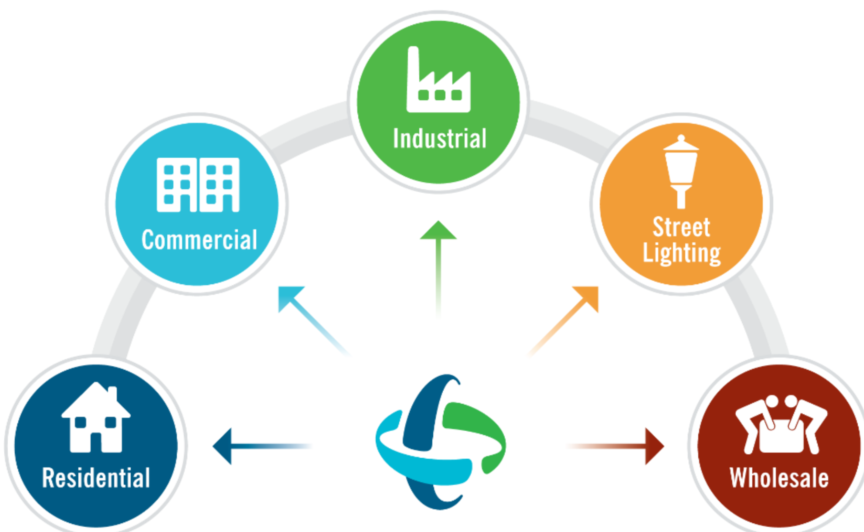
The energy forecast projects the electric load required to serve Duke Energy's retail customer classes. As a product, it is more than just a number— it represents a series of descriptions, offered monthly, hourly or at time of peak — about how demand for energy will evolve under different possible futures. The Companies use econometric analysis, described in more detail below, to prepare models which estimate how historically measured changes in sales can be attributed to variation in a series of predictive variables, measuring economic and weather conditions. Future projections of those predictive variables can then be used to calculate a future outlook for sales measures, as well as demand for energy at time of peak. It is most helpful to consider groups of customers that respond to similar economic dynamics.

Overview of the Forecasting Process

The Companies develop the Load Forecast in four steps: (1) a service area economic forecast is obtained; (2) an energy forecast is prepared by estimating statistical models based on these economic conditions; (3) ex post modifications that account for the growth in electric vehicles ("EVs"), solar and energy efficiency ("EE") programs must be considered; and (4) using the energy forecast, summer and winter peak demand forecasts are developed. The result allows analysis of the impact of varying inputs on sales, including substitution of different economic or weather conditions. This edition of the forecasts includes the years 2024–2038 and represents the needs of the customer classes outlined in Figure D-1 below.

Energy projections are developed with econometric models using key economic factors such as income, electricity prices, industrial production indices, weather, appliance efficiency trends, rooftop solar trends and EV trends. Population is also used in the residential customer model.

Figure D-1: Customer Classes



The economic projections used in the Resource Plan forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the Carolinas. Moody's forecasts consist of economic and demographic projections, which are used in the energy and demand models.

The Retail forecast consists of the three major classes: Residential, Commercial and Industrial. The Residential class sales forecast comprises two projections: (1) the number of residential customers, which is driven by population; and (2) energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices and appliance efficiencies.

The usage per customer forecast was derived using a Statistical Adjusted End-Use Model ("SAE"). This is a regression-based framework that uses projected appliance saturation and efficiency trends developed by Itron using Energy Information Administration ("EIA") data.[1] It incorporates naturally occurring efficiency trends and government mandates more explicitly than other models, combining them with data on economic variables and weather to estimate how demand for energy would change over time as these factors change. The outlook for usage per customer via the end uses is essentially flat early in the forecast horizon, with increasing growth in the later period attributed to the rise in electrification, particularly the increasing growth in EV energy after 2030. Increases in numbers of customers also cause demand for energy to rise throughout the forecast period. The latter force is driven by population growth, so it is not delayed in its impact on the forecast the way the EV-driven sales are.

The Commercial forecast, which predicts aggregate energy demanded, also uses an SAE model to reflect naturally occurring as well as government mandated efficiency changes. The three largest sectors in the commercial class are Offices, Education and Retail.

Total energy from the Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output and the price of electricity.

Weather impacts are incorporated into the models by using Heating Degree Days with a base temperature of 59°F and Cooling Degree Days with a base temperature of 65°F. The forecast of degree days is based on a 30-year average and updated every year. The models use a weighted average of temperatures taken from several weather stations across the service territory, and the Company is careful to include sites in both states.

The appliance saturation and efficiency trends are developed by Itron are based on underlying data from the EIA. These appliance trends are used to calculate end-use variables that constitute the independent variables in the residential and commercial sales models. This calculation is performed by interacting the end-uses with data on weather, economics and effective price, such that the independent variables allow variation in energy sales to be exposed to variation across all of these factors via a time series linear model. To the extent that Duke Energy programs that motivate energy savings (EE programs) affect future demand for energy, those are treated separately from these saturation/efficiency considerations and are deducted from the load forecast afterwards.

Peak demands are projected using the SAE approach and reflect an adjustment for the mix of end-uses at time of peak. The peak forecast was developed using a monthly SAE model, similar to the

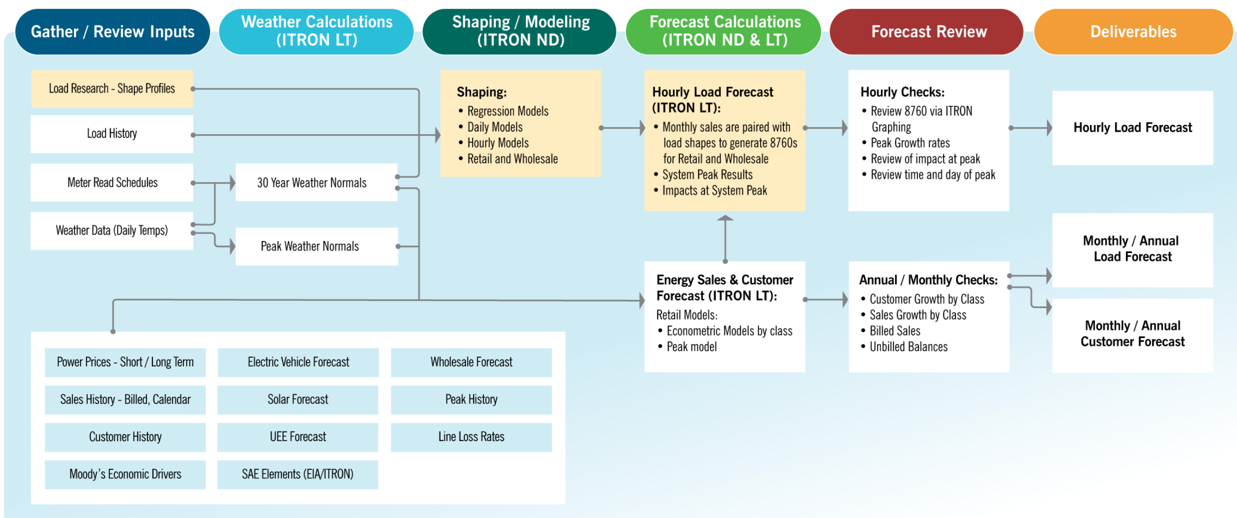
[1] Itron is a recognized firm providing forecasting services to the electric utility industry.

sales SAE models, which includes monthly appliance saturations and efficiencies, interactions with weather and the fraction of each appliance type that is in use at the time of monthly peak.

Forecast Process and Enhancements

The Companies continue to follow a forecast process in line with practices that date to 2013 or even earlier. Much of this process is described in the surrounding text, and Figure D-2 below gives an overview of the workflow with some specific details given special attention immediately following.

Figure D-2: Load Forecasting – Forecasting Process



The Companies began using the SAE model projections to forecast sales and peaks in 2013. The end-use models provide a better platform to recognize long-term trends in equipment and appliance saturation, changes to efficiencies and how those trends interact with heating, cooling and non-weather-related sales. These appliance trends are used in the residential and commercial sales models. In conjunction with peer utilities and Itron, the Companies continually look for refinements to its modeling procedures to make better use of the forecasting tools and develop more reliable forecasts.

Each time the forecast is updated, the most currently available historical and projected data is used. The forecast presented herein utilizes:

- Moody's Analytics January 2023 base and consensus economic projections.
- End use equipment and appliance indices that reflect the 2022 update of Itron's end-use data, which is consistent with EIA's 2022 Annual Energy Outlook.

- A calculation of normal weather using the period 1993–2022.[2]

The Companies also research weather sensitivity of summer and winter peaks, peak history, hourly shaping of sales and load research data in a continuous effort to improve forecast accuracy. The scenario work described below is fruit of that research, which is ongoing. Historical peaks and forecasted peaks are presented later in this Appendix as well.

The relationship between sales and climate change continues to be a consideration with ongoing work building toward a description of how climate change may impact future load. The method described here creates a foundation that could be used for calculating how demand for energy changes in scenarios based on alternative temperature trajectories. To identify potential changes to temperature over time, the Companies intend to use the Representative Concentration Pathway studies and include the assumed temperature changes at the local weather stations, computing the model output based on this temperature forecast in place of the forecast computed under an assumption of “normal weather.” The Companies have also had discussions with their economic provider to obtain a climate change scenario, as climate change will impact economic data under a sufficiently lengthy time frame.

This work is ongoing and is not yet completed for inclusion in the Resource Plan. In the future, when this scenario work is complete, it can be added to the work described below, the results of which are described in other appendices. This design of the forecast process is necessary to accommodate analysis of important scenarios, many of which feature alternative visions of future conditions that would affect the fundamental drivers of the model. Building the statistical models through this rigorous process allows for the consideration of several of these that may be of interest:

- Continuation of the strong economic growth experienced with the Carolinas during recent years is part of the baseline projection, as it aligns with the economic forecast the Companies receive from the vendor. Nevertheless, the economic inputs are varied as part of the analysis to produce Economic High- and Low-scenarios with a focus on the long-term planning horizon. The focus here is on using economic differences to examine via scenario analysis how the system responds to economic growth that significantly underperforms (or outperforms) expectations over the 15-plus-year planning horizon. The results of these scenarios are presented in Appendix C (Quantitative Analysis).

- Significant stresses on the system associated with extreme weather events can be studied through weather scenarios — the 2023 Resource Adequacy Study conducted in support of the Resource Plan is discussed in Appendix C and is included as Attachment I to the Plan.

[2] While the Companies have consistently endeavored to use the most recent data possible, it is important to acknowledge that the rolling “normal weather” period includes the Winter Storm Elliott event from December 2022. Most of the procedures described in this Appendix are directed toward a long-term load forecast, one that is geared toward estimating demand for energy on a horizon of months or years in the future. This is distinct from the short-term load forecast that would be used in a daily or weekly operational horizon.

- Scenarios can also be examined by varying post-estimation adjustments, such as the EE or EV amounts used to adjust the forecast.

Assumptions, Drivers, and Estimation

Below are the projected average annual growth rates of several key drivers from the Resource Plan Forecast. These statistics characterize a region enjoying consistent, durable long-term growth. Following model estimation, a series of adjustments, such as those from behind-the-meter ("BTM") solar and EV charging are made. These are discussed below.

Key Economic Drivers

Table D-1: Annualized Growth Rates of Key Economic Drivers

Driver	2024–2038 CAGR
Real Median Household Income	0.6%
Manufacturing/Industrial Production Index	1.5%
Population	1.4%

Source: All regional data compiled/projected by Moody's Analytics; Compound Average Growth Rate ("CAGR") calculated using starting and ending values for years given.

Table D-1 above lists the projected average annual growth rates of some economic drivers that are relevant when constructing the load forecast. As with previous editions of the forecast, the economic data are combined with price, weather and end-use data to form SAE terms (representing heating, cooling and base load end-uses) for residential and commercial sales models. Models for other categories of customers, such as industrial or government, do not interact with the end use data, but rather are treated as separate terms for estimation. These calculations have been performed to prepare the independent variables so that model estimation can be carried out. Table D-2 and Table D-3 below show the structure for each of the most significant models in both DEC and DEP. The economic drivers used for each major estimation equation are included below, whether as part of an SAE structure or merely in a conventional time series estimation.

Table D-2: Description of DEC Estimation Models

Dependent Variables	SAE-Modeling	Weather Drivers	Economic Drivers
Customer Count (Residential)*	--	--	Change in Population
Usage-Per Customer (Residential)	Y	Heating and Cooling	Real Income Per Household (Median); computed average Household size
Commercial Sales	Y	Heating and Cooling	Population; Commercial Employment; Real Income Per Household (Median)
Industrial Sales	--	Cooling	Industrial Production Index

Note : * Indicates an equation estimated over month-to-month change rather than quantity; weather and economic data are chosen to approximate the service territory based on availability from data vendor and predictive power.

Table D-3: Description of DEP Estimation Models

Dependent Variables	SAE-Modeling	Weather Drivers	Economic Drivers
Customer Count (Residential)*	--	--	Change in Population
Usage-Per Customer (Residential)	Y	Heating and Cooling	Real Income Per Household (Median); computed average Household size
Commercial Sales	Y	Heating and Cooling	Population; Commercial Employment; Real Income Per Household (Median)
Industrial Sales	--	Cooling	Industrial Production Index
Governmental Facility Sales	--	Heating and Cooling	-

Note : * Indicates an equation estimated over month-to-month change rather than level quantity; weather and economic data are chosen to approximate the service territory based on availability from data vendor and predictive power.

Statistically Adjusted End-Use Measures and Energy Efficiency

Utility Energy Efficiency ("UEE") Programs continue to accelerate the adoption of EE by customers. UEE specifically refers to the approved programs offered by DEC and DEP where participants actively take part in conservation measures offered under the EE/Demand-Side Management riders within their service territory. These programs and measures are discussed in further detail in Appendix H (Grid Edge and Customer Programs). When accounting for the efficiency impacts to both energy and peak, careful attention must be paid to two significant challenges: distinguishing between the impacts on load of these UEE programs and the natural evolution of end-use efficiencies and saturations that would occur because of market forces, also referred to as naturally occurring EE.

Naturally occurring EE recognizes load reductions resulting from customers adopting efficiency measures that are not the direct result of a Duke Energy approved program. These efficiency gains are included within the latent forecast variables via the described SAE procedure; this data from the EIA is distributed by Itron via the SAE package and used as predictors for the forecasting model estimation. Naturally occurring EE on the part of customers is important to acknowledge, quantify and remove from the Gross Load Forecast to prevent the double counting of UEE efficiencies with the naturally occurring efficiencies included in the SAE modeling approach.

As both UEE and market-driven efficiency gains are recognized to reduce load during the forecast period, careful attention must be paid to the timing of these efficiency gains to ensure there is not a double counting of these efficiencies. As UEE serves to accelerate the timing of naturally occurring efficiency gains, the forecast “rolls off” or ends the UEE savings at the conclusion of its measure life — a moment at which market-incentives would have brought end-use demands into alignment with the projections had the Duke Energy-based UEE programs not been in effect. For example, if the accelerated benefit of a residential UEE program is expected to have occurred seven years before the energy reduction program would have been otherwise adopted, then the UEE effects after year seven are subtracted (“rolled off”) from the total cumulative UEE. With the SAE model’s framework, the naturally occurring appliance efficiency trends replace the rolled off UEE benefits serving to continue to reduce the forecasted load resulting from EE adoption. The impact of this interaction between naturally occurring EE and UEE is to recognize the earlier adoption of EE improvements, lowering energy usage earlier than would have otherwise been expected, and continuing the benefit of the EE over the forecasting period. A similar consideration is made by the Companies regarding the reductions in load that are expected to occur as a result of the passage of the Inflation Reduction Act of 2022[3] (“IRA”), and more details on how modifications to these calculations account for this law are given below. There are also a series of programs related to EE and Grid Edge programs in which rate design is used to motivate consumer-driven modifications in load: these are discussed in detail in Appendix H.

For purposes of this document, UEE and EE terms may be used interchangeably to refer to approved utility programs unless otherwise noted. It is important to note that data regarding the change in metered energy that is attributed to UEE must be explicitly added to the forecast after estimation to properly account for how these efforts by Duke Energy will reduce the energy demanded by its customers. Table D-4 and Table D-5 below illustrate the impact of this process on annual sales projections for DEC and DEP separately.

[3] Inflation Reduction Act, S. Con. Res., 117th Cong. (2022).

Table D-4: DEC 1% Base Scenario, Impacts in Gigawatt-hour ("GWh")

Year	Forecast Before UEE	Historical UEE Roll Off	Forecast With Historical Roll Off	Forecasted UEE Incremental Roll on	Forecasted UEE Incremental Roll Off	UEE to Subtract From Forecast	Forecast After UEE
2024	96,568	12	96,580	(1,175)	362	(814)	95,767
2025	97,163	36	97,199	(1,704)	362	(1,342)	95,857
2026	98,130	89	98,219	(2,230)	362	(1,868)	96,351
2027	99,724	181	99,904	(2,752)	364	(2,388)	97,516
2028	101,918	313	102,230	(3,282)	366	(2,916)	99,315
2029	104,068	447	104,515	(3,814)	368	(3,446)	101,069
2030	105,966	644	106,610	(4,342)	373	(3,969)	102,640
2031	108,064	798	108,863	(4,862)	392	(4,469)	104,393
2032	110,310	914	111,224	(5,367)	436	(4,931)	106,293
2033	112,572	990	113,562	(5,801)	550	(5,252)	108,310
2034	114,302	1,026	115,328	(6,175)	723	(5,451)	109,876
2035	116,236	1,039	117,274	(6,536)	934	(5,602)	111,672
2036	118,241	1,039	119,279	(6,886)	1,191	(5,695)	113,584
2037	120,143	1,039	121,181	(7,225)	1,498	(5,726)	115,455
2038	122,242	1,039	123,280	(7,555)	1,939	(5,616)	117,664

Table D-5: DEP 1% Base Scenario, Impacts in GWh

Year	Forecast Before UEE	Historical UEE Roll Off	Forecast With Historical Roll Off	Forecasted UEE Incremental Roll on	Forecasted UEE Incremental Roll Off	UEE to Subtract From Forecast	Forecast After UEE
2024	65,856	5	65,860	(618)	193	(425)	65,435
2025	67,463	18	67,480	(893)	193	(700)	66,781
2026	68,277	39	68,316	(1,177)	194	(983)	67,333
2027	69,113	75	69,188	(1,467)	195	(1,273)	67,915
2028	70,307	128	70,435	(1,750)	196	(1,555)	68,880
2029	71,560	193	71,753	(2,022)	197	(1,825)	69,928
2030	72,860	255	73,115	(2,286)	200	(2,086)	71,029
2031	73,891	345	74,235	(2,540)	209	(2,330)	71,905
2032	74,914	413	75,326	(2,781)	231	(2,550)	72,777
2033	75,862	464	76,326	(2,982)	289	(2,693)	73,633
2034	76,780	498	77,278	(3,160)	379	(2,780)	74,498
2035	77,826	514	78,340	(3,343)	482	(2,861)	75,479
2036	78,974	519	79,493	(3,530)	602	(2,928)	76,566
2037	80,015	519	80,535	(3,722)	751	(2,971)	77,563
2038	81,113	519	81,632	(3,919)	956	(2,964)	78,668

The Companies are continuing their review of the IRA. The policies contained therein promise a variety of impacts on income via government incentives as well as on the deployment of EVs and the efficiency levels of appliances, or the time horizon in which these impacts represent an acceleration of market-driven improvements that would have occurred naturally. The UEE and EV calculations have been adjusted to respond to details of this law, while other inputs, such as the end-use data, have not had a refresh cycle since its passage. As more information comes to light, the figures herein may be adjusted as part of the forecast refresh process in the future.

A second problem, which affects those causal estimates of the salience of Duke Energy's own programs as well as measuring any impact of the IRA, is the changing composition of new, large customers. In an environment in which new, large customers are added to the system, the innate efficiency of their sites, which are built with the newest, most efficient equipment, makes participation in the Companies' EE programs relatively less attractive for these newer customers, a problem commonly referred to as adverse selection. This means that reaching a target of 1% (or any other stated target), requires an "overshoot" of participation from existing customers such that the computation of program participation over total energy will reach the target level. Forecasts developed in the Resource Plan take this into account through the trajectory of program growth over time that is presented.

Customer Growth

Table D-6 through Table D-9 below show the history and projections for the number of customers; each major customer class is estimated using the statistical methods described above. Historical Retail Customer growth over the presented period is 1.6% for both DEC and DEP, while Projected Retail Customer growth is 1.1% and 1.0%, respectively, for DEC and DEP. The recent years have seen strong growth for both territories here.

Table D-6: DEC Customer Counts, Historical in 000s

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2013	2,068	339	7	14	2,428
2014	2,089	342	7	15	2,452
2015	2,117	345	6	15	2,484
2016	2,148	349	6	15	2,519
2017	2,182	354	6	15	2,557
2018	2,215	358	6	17	2,596
2019	2,261	362	6	22	2,651
2020	2,306	367	6	23	2,702
2021	2,350	392	6	16	2,764
2022	2,378	400	6	11	2,796
Avg. Annual Growth Rate	1.6%	1.9%	-0.9%	-2.7%	1.6%

Table D-7: DEP Customer Counts, Historical in 000s

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2013	1,242	222	4	2	1,470
2014	1,257	223	4	2	1,486
2015	1,275	226	4	2	1,507
2016	1,292	229	4	2	1,527
2017	1,310	232	4	1	1,547
2018	1,331	235	4	1	1,571
2019	1,349	237	4	1	1,591
2020	1,375	239	4	1	1,620
2021	1,397	242	4	2	1,644
2022	1,435	248	3	3	1,689
Avg. Annual Growth Rate	1.6%	1.3%	-3.0%	4.0%	1.6%

Table D-8: DEC Customer Count, Projected in 000s

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2024	2,452	407	6	13	2,878
2025	2,482	411	6	14	2,913
2026	2,511	415	6	14	2,947
2027	2,540	419	6	15	2,980
2028	2,570	423	6	15	3,014
2029	2,600	427	6	15	3,049
2030	2,631	431	6	15	3,084
2031	2,662	436	6	15	3,119
2032	2,693	440	6	15	3,154
2033	2,724	444	6	15	3,189
2034	2,754	448	6	15	3,223
2035	2,784	452	6	15	3,256
2036	2,812	455	6	15	3,289
2037	2,840	459	6	15	3,320
2038	2,868	462	6	15	3,351
Avg. Annual Growth Rate	1.1%	0.9%	-0.3%	1.2%	1.1%

Table D-9: DEP Customer Count, Projected in 000

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Retail Customers
2024	1,477	250	3	2	1,732
2025	1,493	252	3	2	1,751
2026	1,510	253	3	2	1,768
2027	1,527	255	3	2	1,786
2028	1,543	256	3	2	1,804
2029	1,560	258	2	2	1,823
2030	1,578	260	2	2	1,842
2031	1,596	261	2	2	1,862
2032	1,613	263	2	2	1,881
2033	1,630	264	2	2	1,899
2034	1,648	266	2	2	1,918
2035	1,664	267	2	2	1,937
2036	1,680	269	2	3	1,954
2037	1,696	270	2	3	1,972
2038	1,712	272	3	3	1,989
Avg. Annual Growth Rate	1.1%	0.6%	-1.2%	0.4%	1.0%

For residential energy modeling, the growth in customers constitutes an intermediate input, as the total residential energy is computed by multiplying customers times a per-customer usage.

Critical Peak Pricing

The Critical Peak Pricing ("CPP") Rate Rider is a dynamic overlay option for the Companies' electric service, including both its existing flat volumetric rates as well as its existing and newly proposed time-of-use ("TOU") rates. This time variant pricing option allows Duke Energy to call critical events up to 20 times per year ("20 CP") based on system conditions such as expected extreme temperatures, high energy usage, high market energy costs or major generation or transmission outages. Customers enrolled will be alerted the day before a critical event is expected and agree to pay a higher price for peak time electricity use during these critical events, encouraging reductions in demand. Daily load and peak impacts for CPP were included in the peak demand projections for DEC and DEP in the Resource Plan. The critical events (20 CP) were modeled to impact the projected 10 highest winter days and 10 highest summer days in each year of the Resource Plan. Table D-10 below shows the CPP projected peak reduction capabilities for winter and summer demands.

Table D-10: Critical Peak Pricing Peak Reduction Capabilities

	DEC		DEP	
Year	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
2024	24	17	39	29
2025	38	29	62	50
2026	55	44	91	76
2027	76	62	125	107
2028	100	83	164	144
2029	126	106	206	108
2030	153	132	251	133
2031	180	158	296	160
2032	207	184	339	185
2033	231	207	378	210
2034	252	229	413	231
2035	270	247	441	249
2036	284	263	465	265
2037	296	275	484	277
2038	305	285	498	287

Adjustments for Economic Development Activity

The Companies devote resources to promoting and enabling the long-term flourishing of the region, including attracting new industries and businesses to the area and partnering with these incoming companies to plan for their energy needs as they connect with employees and customers. Aligning with the activities in this space requires a consideration of economic development results, particularly when efforts to attract these investments look to make significantly large changes when compared with the scale of the grid stewarded by the Companies. However, a tension exists — the very same economic data to which load forecast models are exposed, predict a vigorous and healthy economy which should include many new investments and site openings (as well as the closings that are a natural part of regional economic churn). When the load forecasting team receives a list of potential site openings and closings, a qualification process is followed to screen these adjustments to load, and then apply them to the forecast when the most mature projects exceed a threshold size relative to statistical forecasting error. Several of the largest potential projects were used to adjust the forecast this cycle, although the size of the adjustment (in both megawatt-hours ("MWh") and megawatts ("MW")) was scaled down from full weight to reflect both the uncertain, future-oriented nature of the plans and the risk of double counting with growth precited by the economic factors. Conversely, if recent trends in significant economic development expansion in the Carolinas persist, the Companies may need to reflect such increased activity in future load forecasts as well as future resource planning cycles. This will be a particular focus area for future forecasts given the dynamic nature of many macro variables impacting large economic development potential in the Carolinas. Such macro variables include, but are not limited to, continuing population growth through in-migration to the region, EV adoption rates and supporting infrastructure needs for the electric auto industry, trends toward onshoring of global manufacturing in response to the IRA and geopolitical uncertainty, rate of growth in data computing needs to support rapid expansion of infrastructure for cloud computing, artificial intelligence, and electronic currency as well as the impact of future state and federal policies to either promote or inhibit economic expansion in the Carolinas to name just a few.

To stay abreast of these uncertainties, the Companies' Economic Development teams and Large Account Management teams continually devote resources toward tracking and engaging with a series of potential development projects at various stages of consideration or buildout, with many of these submitted for consideration to the load forecasting team. Ultimately, the team elevated several of these projects — ones that were of large magnitude, (the largest often are referred to as "mega-projects") and with plans sufficiently advanced such that the demand could be anticipated with a high degree of certainty — into a rarified group that were used to adjust the load forecast beyond what would have occurred only based on the calculations from the economic and other independent predictors. Consideration may also be given to a site that might be suddenly closing (i.e., withdrawing demand from the system if that site meets similar criteria).

Astute readers will point out that combining such calculations with the results of an econometric model introduces a possibility of some double counting to the extent that economic forces motivate the individual site adjustments. To mitigate the impact of a possible "double count," the load forecasting team typically adjusts the load forecast by a reduced amount of the full load expectation for each project; this consideration results in a discount of 30%–60%, depending on the extent to which informal statistical calculation suggests that aggregate sales are explained by the relevant economic indicator for that customer class. Table D-11 below lists the adjustments applied to the annual forecast based on these "Large Site Adjustments" within both territories. Indeed, the portfolio of active projects is large and reflects a significant number of mega-projects with active construction activity that exceed the size threshold standard. When previous projects were considered during the recent past, their size and scale was below a threshold that would have motivated actively modifying the forecast based on the confidence intervals of the statistical work.

Table D-11: Adjustments in the Load Forecast for Large Site Developments in MWh

Year	DEC	DEP
2023	139,023	--
2024	711,032	525,627
2025	1,016,318	946,087
2026	1,504,031	1,288,761
2027	2,122,049	1,723,534
2028	2,931,801	2,120,269
2029	3,518,174	2,402,781
2030	4,104,546	2,765,064
2031	4,690,919	2,892,107
2032	5,277,291	2,892,107
2033	5,863,664	2,892,107
2034	5,863,664	2,892,107
2035	5,863,664	2,892,107
2036	5,863,664	2,892,107
2037	5,863,664	2,892,107
Avg. Annual Growth Rate	**25.0%**	**13.0%**

In summary, the size, scale and speed of economic development of mega-projects has dramatically increased over the past two years, such that a greater proportion of the portfolio is above the threshold where an explicit addition to the forecast is appropriate. Duke Energy has played a critical role in partnering with local and state economic development entities to ensure the successful recruitment of these highly competitive mega-projects to the DEC and DEP service areas. The Companies have seen specific success in the emerging EV sector to include vehicle manufacturing, battery production and associated supply chain along with “re-emerging” industries such as steel production, semi-conductors and large-scale data centers.

Rooftop Solar

BTM or rooftop solar or solar photovoltaic (“PV”) is currently available in the Carolinas. The forecast used in the Resource Plan reflects impacts from approved rates in the Carolinas as of January 1, 2023, which are decremented directly from the initial Itron model output. Table D-12 below summarizes the number of current customers enrolled in these programs for both the DEC and DEP service areas by customer class, as well as the total energy in MWh forecasted to be generated from BTM solar generation on customer sites in 2023.

Table D-12: Number of Customers Enrolled in Behind-the-Meter Rate Programs and Forecasted BTM Generation

System	2023 Enrollment (as of 1/1/2023)		2023 BTM Generation Forecast (MWh)	
	Residential	Non-Residential	Residential	Non-Residential
DEC	28,858	839	288,183	94,054
DEP	19,030	542	193,539	47,590

As noted, the BTM solar forecast was based on the tariffs and programs applicable at the time of the forecast. Since the forecast was completed, the NCUC issued an order that approved new net metering tariffs, per Docket No. E-100, Sub 180. Key features of the new net metering tariff include a minimum bill, non-bypassable charges for storm recovery, grid access fees for larger systems, TOU rates and exports credited at avoided cost. There is an alternative version known as a bridge rate that does not require TOU rates, which is limited to a set amount of capacity for each year through 2026. The new tariffs are scheduled to take effect starting October 1, 2023.

The general view is that the new net metering tariffs may result in somewhat lower net metering adoptions, although favorable tax treatments included in the IRA and a projected declining forward cost curve could help to counteract impacts of the new tariffs. A detailed quantitative comparison of the forecasts is not included as part of this analysis.

Modeling Behind-the-Meter Solar Adoption

Residential rooftop solar systems are limited in size under state law in the Carolinas, which require the facility to be less than 20 kilowatts-alternating current ("kW-AC"), also referred to as nameplate capacity for solar facilities. Non-residential customers' solar systems may not exceed the lesser of 1,000 kW-AC or 100% of the customer's contract demand, which approximates the customer's maximum expected demand. Table D-13 below shows the average size of rooftop solar facilities in the Carolinas.

Table D-13: Average Rooftop Solar Capacity per Installation (kW-AC) for NC and SC

DEC		
Customer Class	North Carolina	South Carolina
Residential	6.7	8.1
Non-residential	61.5	112.7
DEP		
Customer Class	North Carolina	South Carolina
Residential	7.2	8.0
Non-residential	50.4	131.9

The rooftop solar generation forecast is derived from a series of capacity forecasts and hourly production profiles tailored to residential, commercial and industrial customer classes.

Each capacity forecast is the product of a customer adoption forecast and an average capacity value. The adoption forecasts are developed using economic models of payback, which is a function of installed cost, regulatory incentives, regulatory statutes and bill savings. A relationship between payback and customer adoption is developed through regression modeling, with the resulting regression equations used to predict future customer adoptions based on projected payback curves.

Historical and projected technology costs are sourced from Guidehouse, while projected incentives and bill savings are based on current regulatory policies as well as input from internal subject matter experts. Average system size (capacity) values are based on trends in historical adoption.

The hourly production profiles have 12x24 resolution, which equates to one 24-hour profile for each month. Profiles are derived from actual production data, where available, and solar PV modeling. The PV modeling is performed in the PVsyst model using 20-plus years of historical irradiance data sourced from Solar Anywhere and Solcast. Models are created for 13 irradiance locations across DEC's service area and nine irradiance locations across DEP's service area with 21 tilt/azimuth configurations. The results for each jurisdiction are combined on a weighted average basis to produce the final profiles. Tables D-14 below show the Companies' growth projections for new solar customers and the new energy benefits for 2023 and 2037.

Table D-14: Growth Projections for New Solar Customers and Energy Benefits

		Customers		Energy (MWh)	
	Year	**Residential**	**Non-Residential**	**Residential**	**Non-Residential**
DEC	**2023**	8,215	213	42,924	9,591
	2037	122,326	2,973	1,169,079	243,583
DEP	**2023**	6,291	248	34,776	7,041
	2037	82,889	1,961	817,702	102,667

Note: The data reflects net new additions starting from 1/1/2023.

Note: The 2023 data indicates the total number of new customers added expected in 2023 as well as the projected energy from these customers for 2023.

Note: The 2037 data indicates the accumulated total number of new customers added from 1/1/2023 through 12/31/2037 and the projected energy from these customers for 2037.

Electric Vehicles

The transportation industry is undergoing a massive transition to EVs from traditional combustion engine vehicles. In 2022, 5%–6% of new vehicles sold were EVs compared to 3%–4% in 2021. This number is expected to continue to grow, especially considering federal initiatives and automaker goals of, by 2030, having at least 50% of new vehicle sales being EVs. This transition to EVs will require diligent planning and forecasting to provide the energy required to charge the EVs while maintaining grid reliability. In addition to its EV forecasting methodology outlined below, Duke Energy is continuing to monitor and evaluate EV load management and managed charging programs and pilots which will provide additional insights when forecasting EV charging characteristics. For additional details on EV load management programs see Appendix H.

Duke Energy develops its EV load forecast by using the Guidehouse Vehicle Analytics and Simulation Tool. The tool first develops a vehicle forecast based on multiple parameters including historical data, such as vehicle registrations (IHS Markit) and forecasted data, such as vehicle utilization and efficiency characteristics (Argonne National Lab), projections of fuel costs (from EIA and Automotive Association of America), future vehicle availability and consumer acceptance (Guidehouse insights) and vehicle miles traveled (from Federal Highway Administration). These variables, along with others, help determine the total cost of ownership of a vehicle which is used in the development of the forecasted vehicle adoption.

Once the vehicle adoption forecast is created, the associated energy and load associated are forecasted. Variables to determine energy, such as vehicle miles traveled and vehicle efficiency, can be used to calculate charging energy requirements for the vehicles. Then associated load charging profiles are derived from public, private and third-party analysis. These charging profiles are broken down by three duties: light, medium and heavy. Based on the adoption forecast, the projected amount of energy needed to charge the EVs and the hourly EV demand profiles, the jurisdictional EV hourly forecast is developed. All three duties are calculated using similar methodology and make up the EV load forecast that is added to the Duke Energy load forecast.

In recent years, EV adoption has grown rapidly and is forecasted to continue to quickly grow with the tailwinds of federal and state incentives, automaker commitments to increase EV sales and more vehicles coming available. These adoption trends have resulted in a higher forecast than what was previously forecasted in previous years. The forecast results in Table D-15 and Table D-16 below show the number of EVs that are projected to be in operation at the end of 2023 and forecasted to be in operation in 2037, the associated percent it represents of the entire vehicle fleet and the net new energy associated with those vehicles.

Table D-15: Electric Vehicles, EVs in Operation and Load Impacts – DEC

Year	EVs in Operation	Percent of Vehicle Fleet	Net New Load (MWh/Year)
2023	45,638	0.82%	25,518
2037	2,074,921	31.03%	7,380,537

Table D-16: Electric Vehicles, EVs in Operation and Load Impacts – DEP

Year	EVs in Operation	Percent of Vehicle Fleet	Net New Load (MWh/Year)
2023	31,231	0.94%	16,004
2037	1,282,384	31.80%	4,450,652

Net Impact of Rooftop Solar and Electric Vehicles

Figure D-3 through Figure D-8 below illustrate the impacts on annual energy, winter peak demand and summer peak demand from rooftop solar and EVs by customer class across the planning horizon. The load forecast is incremented by these projections. More detailed discussion of both parts can be found in their own respective appendices.

Figure D-3: Percent Impact of PV and EV on Annual Load in DEC, Net New from 2023

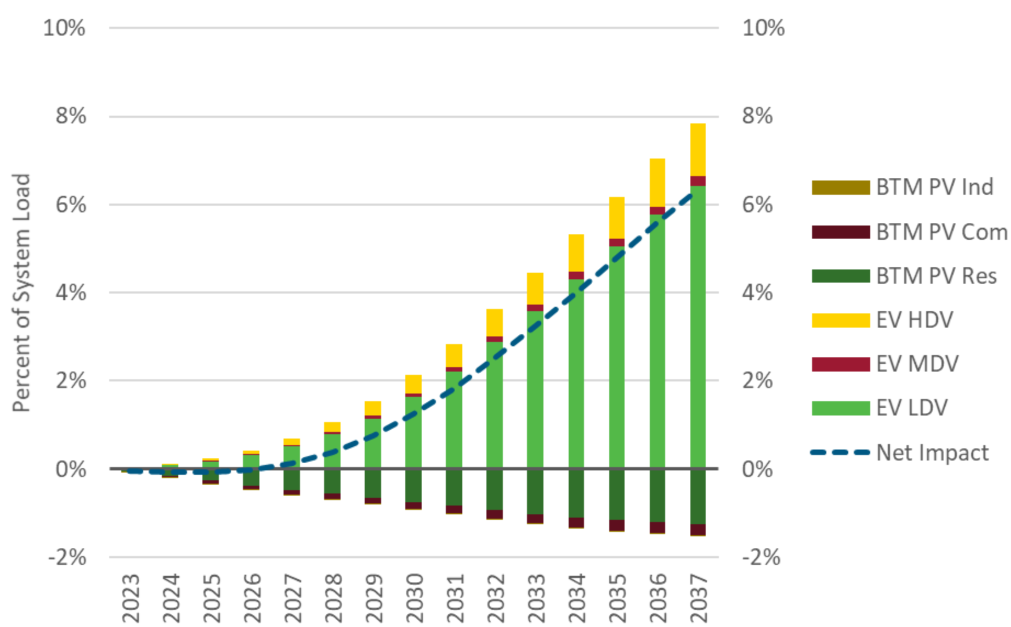


Figure D-4: Percent Impact of PV and EV on Winter Peak Load in DEC, Net New from 2023

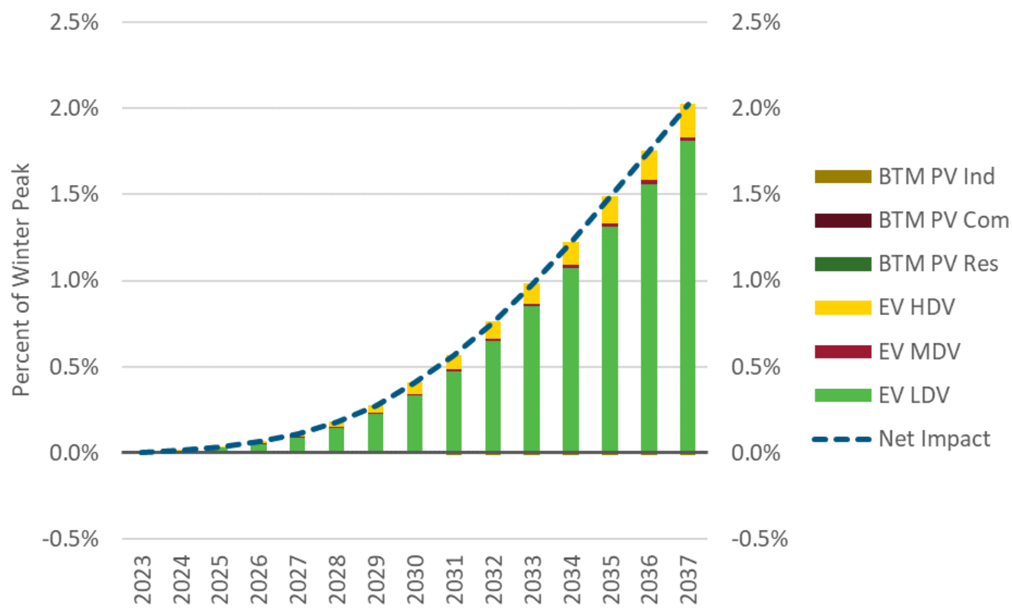


Figure D-5: Percent Impact of PV and EV on Summer Peak Load in DEC, Net New from 2023

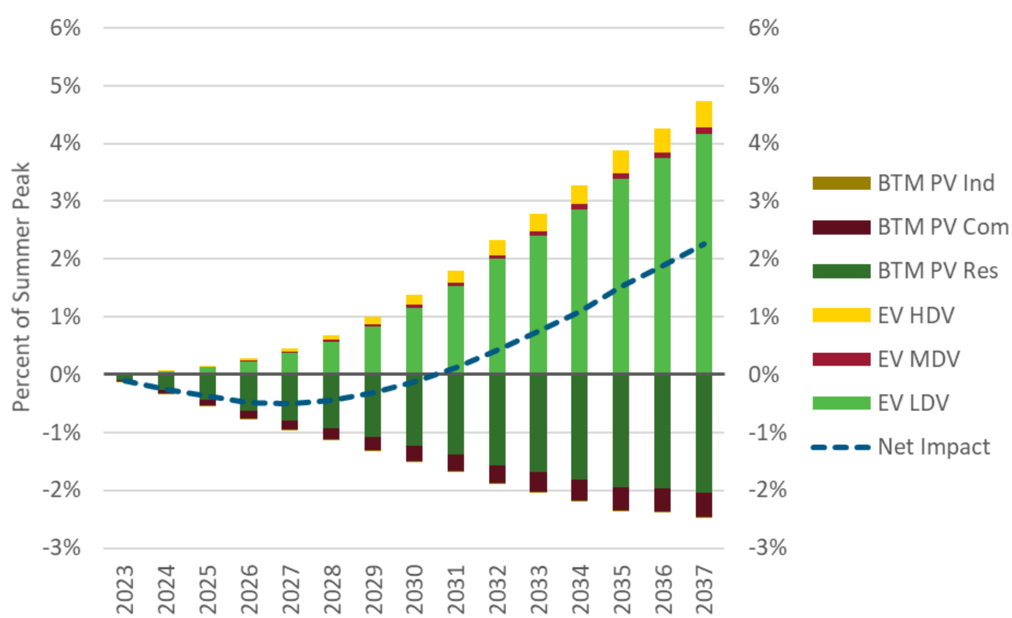


Figure D-6: Percent Impact of PV and EV on Annual Load in DEP, Net New from 2023

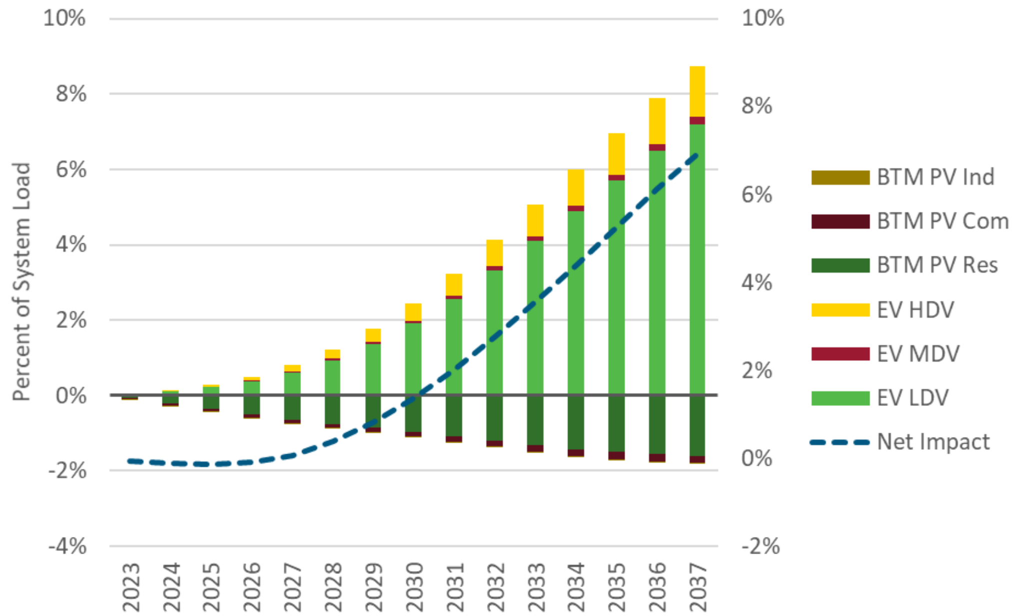


Figure D-7: Percent Impact of PV and EV on Winter Peak Load in DEP, Net New from 2023

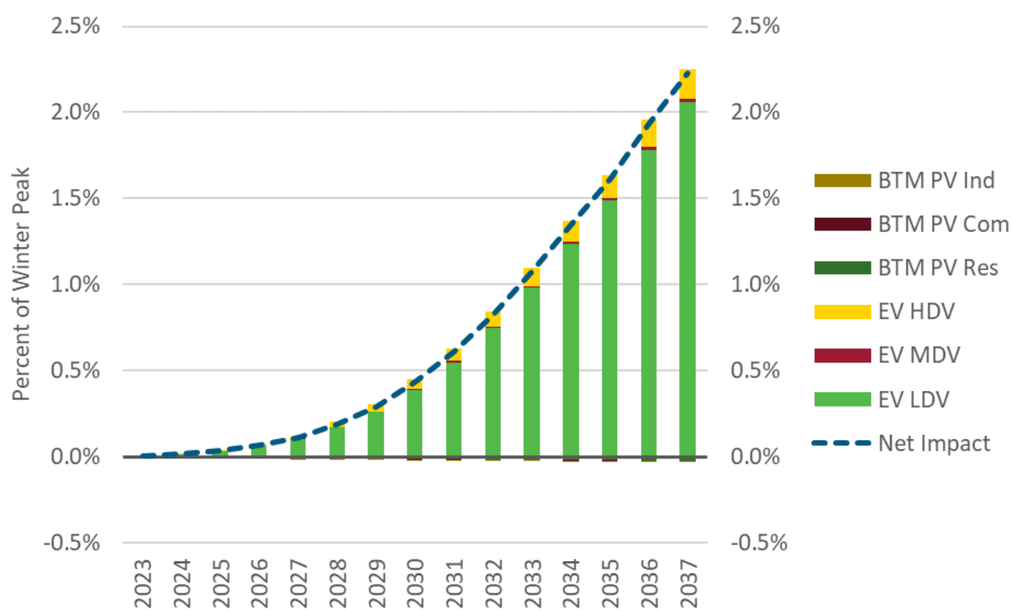
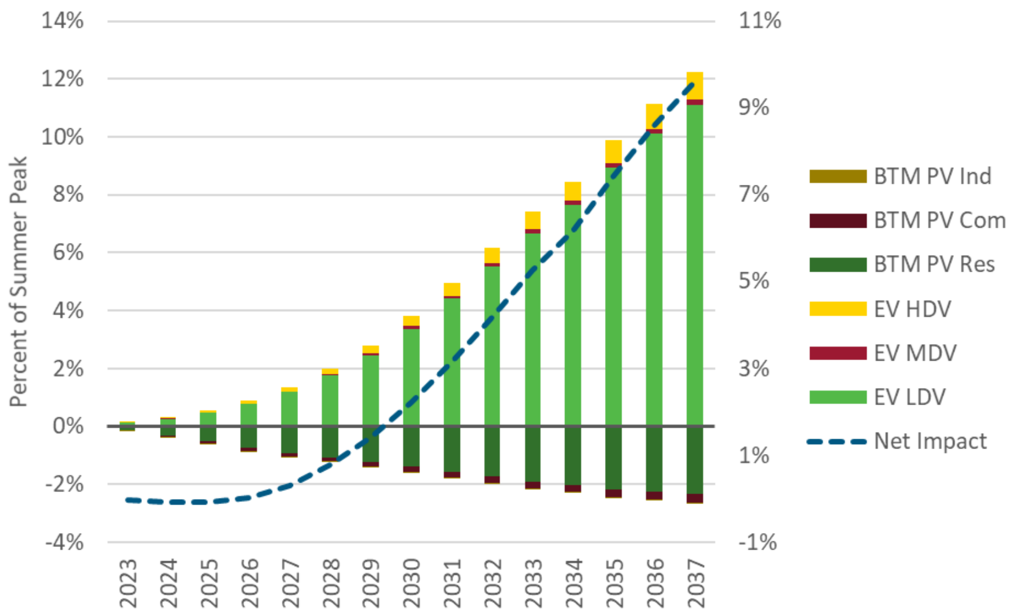


Figure D-8: Percent Impact of PV and EV on Summer Peak Load in DEP, Net New from 2023



Forecast Results and Commentary

With regard to the long-term forecast, the Resource Plan shows both annual energy and peak demand at a higher level than the previous editions. The details have been discussed above, but a few charts are presented here to display the sources for that growth crisply.

Figure D-9 below displays the level changes (in gigawatt-hours ("GWh")) in the energy forecast across both DEC and DEP attributable to these main causes, with a focus on years 2035–2037 (the average is displayed because rapid energy growth from EVs would shift the results depending on the year). The factors included in "All Other" are ones that lead to both decreases and increases in the forecast. Figure D-10 shows how these same factors — and some others — lead to changes in energy demanded at time of winter peaks. The Companies project increasing impact of EVs further out in time.

Figure D-9: Composition of Level Changes in Peak Forecast (GWh)

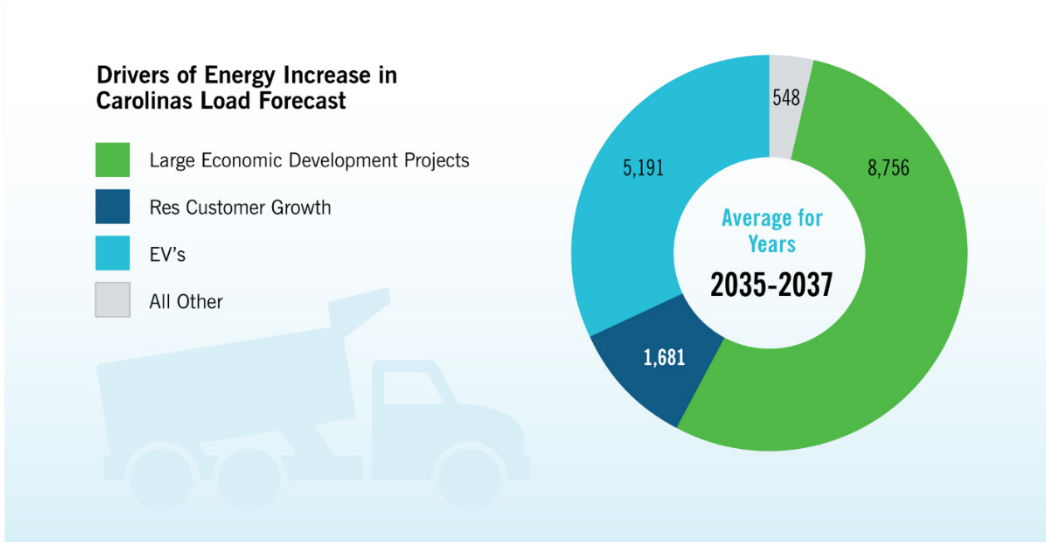
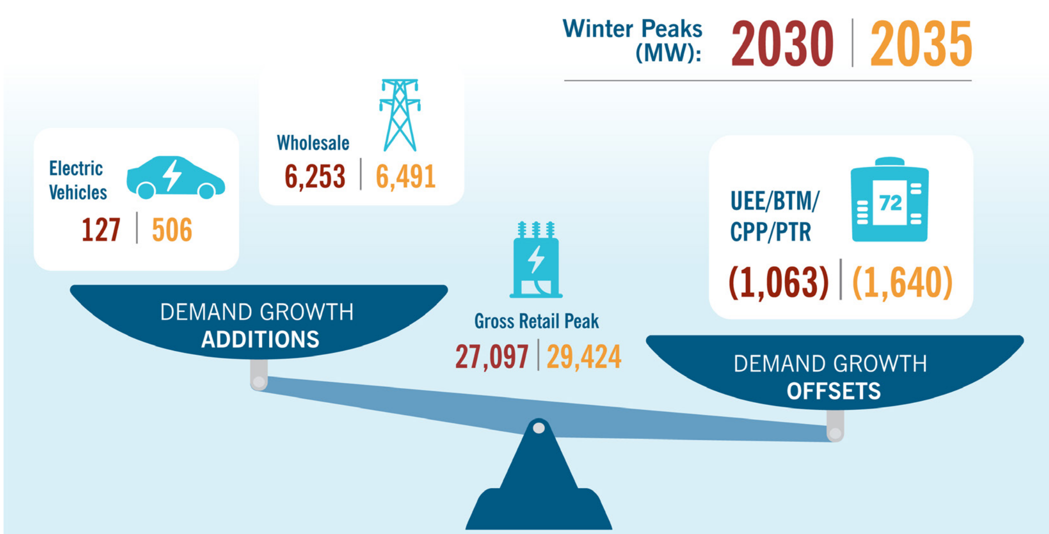


Figure D-10: Major Drivers of Peak Forecast Increase



Note: Units are change in MW when comparing most recent resource plans with the Carolinas Resource Plan.

Historical and Projected Load Forecast Information

Tables D-17 through D-20 and Figures D-11 through D-14 below provide historical and projected load forecast information pertaining to customers and energy sales.

Table D-17: DEC – Historical Sales in GWh

Year	Residential	Commercial	Industrial	Military & Other	Retail	Wholesale	Total System
2013	26,895	27,765	21,070	293	76,023	5,824	81,847
2014	27,976	28,421	21,577	303	78,277	6,559	84,836
2015	27,916	28,700	22,136	305	79,057	6,916	85,973
2016	27,939	28,906	21,942	304	79,091	7,614	86,705
2017	26,593	28,388	21,776	301	77,059	7,558	84,617
2018	29,717	29,656	21,720	306	81,399	8,889	90,288
2019	28,861	29,628	21,299	320	80,109	8,317	88,426
2020	27,963	27,637	19,593	314	75,506	7,616	83,123
2021	29,244	28,760	20,611	300	78,915	7,966	86,880
2022	29,377	29,536	20,811	296	80,019	8,123	88,142
Avg. Annual Growth Rate	1.0%	0.7%	-0.1%	0.1%	0.6%	3.8%	0.8%

Table D-18: DEP – Historical Sales in GWh

Year	Residential	Commercial	Industrial	Military & Other	Retail	Wholesale	Total System
2013	16,663	13,581	10,508	1,602	42,355	12,676	55,031
2014	18,201	13,887	10,321	1,614	44,023	13,578	57,601
2015	17,954	14,039	10,288	1,597	43,876	15,782	59,658
2016	17,686	14,082	10,274	1,563	43,606	18,676	62,282
2017	17,228	13,903	10,391	1,531	43,053	18,242	61,295
2018	18,939	14,219	10,475	1,560	45,194	19,331	64,525
2019	18,177	13,992	10,534	1,537	44,241	18,694	62,935
2020	17,587	12,894	10,122	1,495	42,099	17,216	59,315
2021	18,645	12,941	9,343	1,389	42,318	17,821	60,139
2022	18,499	13,822	11,037	1,600	44,958	18,051	63,009
Avg. Annual Growth Rate	1.2%	0.2%	0.5%	0.0%	0.7%	4.0%	1.5%

Table D-19: DEC – Retail Sales (GWh Sold – Years Ended December 31)

Year	Residential	Commercial	Industrial	Other	Retail
2024	30,532	30,142	20,953	291	81,918
2025	30,212	29,981	21,489	290	81,972
2026	30,169	29,910	22,018	290	82,387
2027	30,258	30,291	22,592	289	83,429
2028	30,626	30,949	23,191	289	85,056
2029	30,957	31,784	23,630	288	86,660
2030	31,292	32,488	24,014	287	88,082
2031	31,741	33,195	24,450	287	89,673
2032	32,311	33,929	24,864	286	91,390
2033	32,926	34,728	25,303	285	93,242
2034	33,725	34,906	25,746	285	94,661
2035	34,654	35,149	26,211	284	96,298
2036	35,637	35,438	26,675	283	98,034
2037	36,648	35,682	27,142	282	99,754
2038	37,799	36,010	27,691	281	101,781
Avg. Annual Growth Rate	1.4%	1.2%	1.9%	-0.2%	1.5%

Table D-20: DEP – Retail Sales (GWh Sold – Years Ended December 31)

Year	Residential	Commercial	Industrial	Other	Retail
2024	19,169	13,829	10,665	1,515	45,178
2025	19,126	13,873	11,120	1,511	45,630
2026	18,952	13,796	11,451	1,507	45,705
2027	18,922	13,776	11,863	1,502	46,062
2028	19,129	13,861	12,292	1,499	46,780
2029	19,456	14,028	12,621	1,496	47,601
2030	19,790	14,131	13,038	1,497	48,456
2031	20,137	14,233	13,219	1,495	49,083
2032	20,547	14,352	13,277	1,494	49,670
2033	21,035	14,487	13,355	1,494	50,370
2034	21,538	14,600	13,445	1,492	51,075
2035	22,111	14,748	13,535	1,492	51,886
2036	22,757	14,921	13,625	1,491	52,794
2037	23,349	15,067	13,705	1,490	53,611
2038	24,014	15,237	13,784	1,491	54,526
Avg. Annual Growth Rate	1.5%	0.6%	1.7%	-0.1%	1.3%

Figure D-11: DEC Actual and Weather Normal Winter Peaks

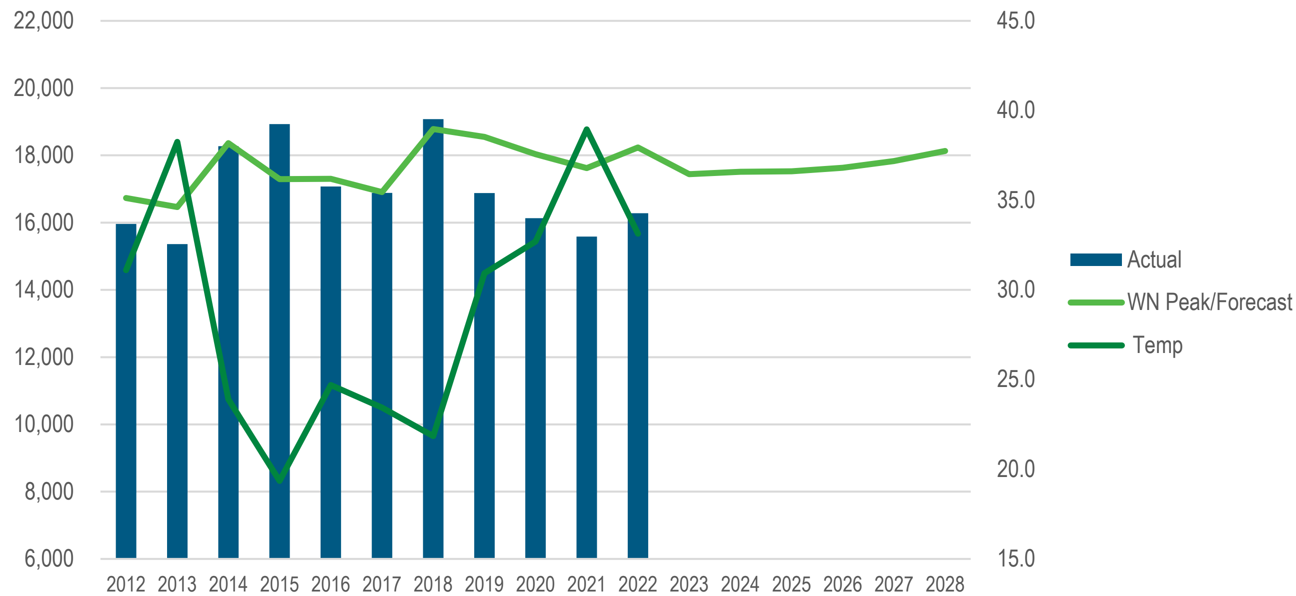


Figure D-12: DEC Actual and Weather Normal Summer Peaks

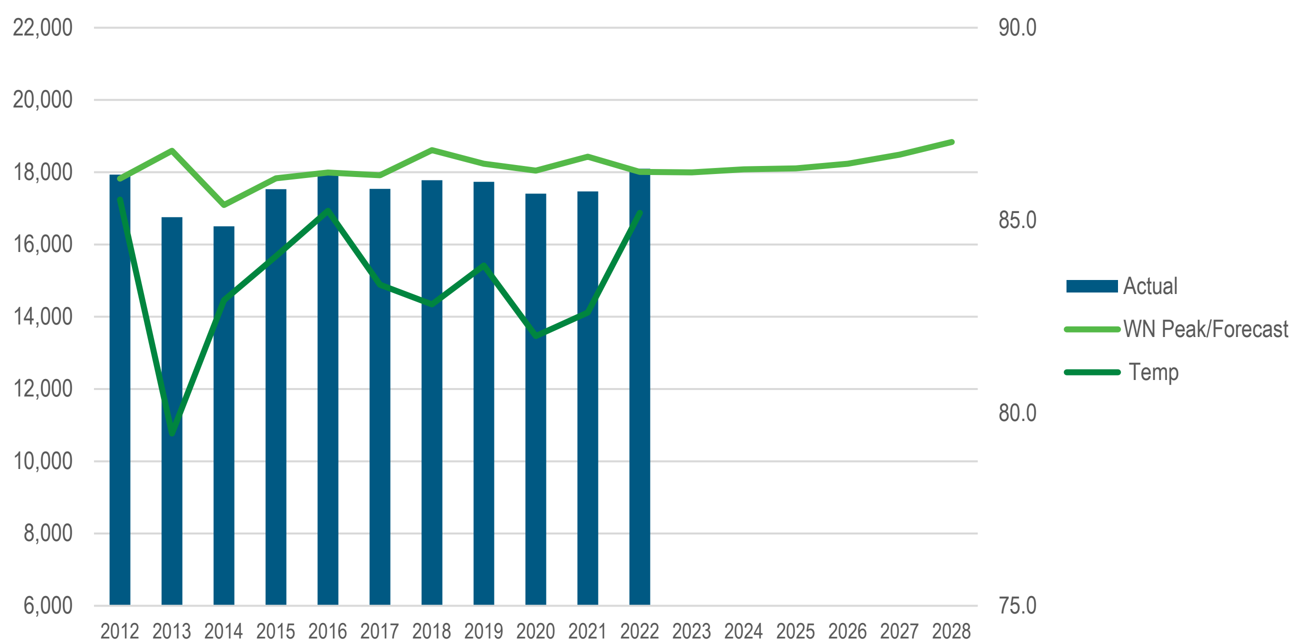


Figure D-13: DEP Actual and Weather Normal and Forecasted Winter Peaks

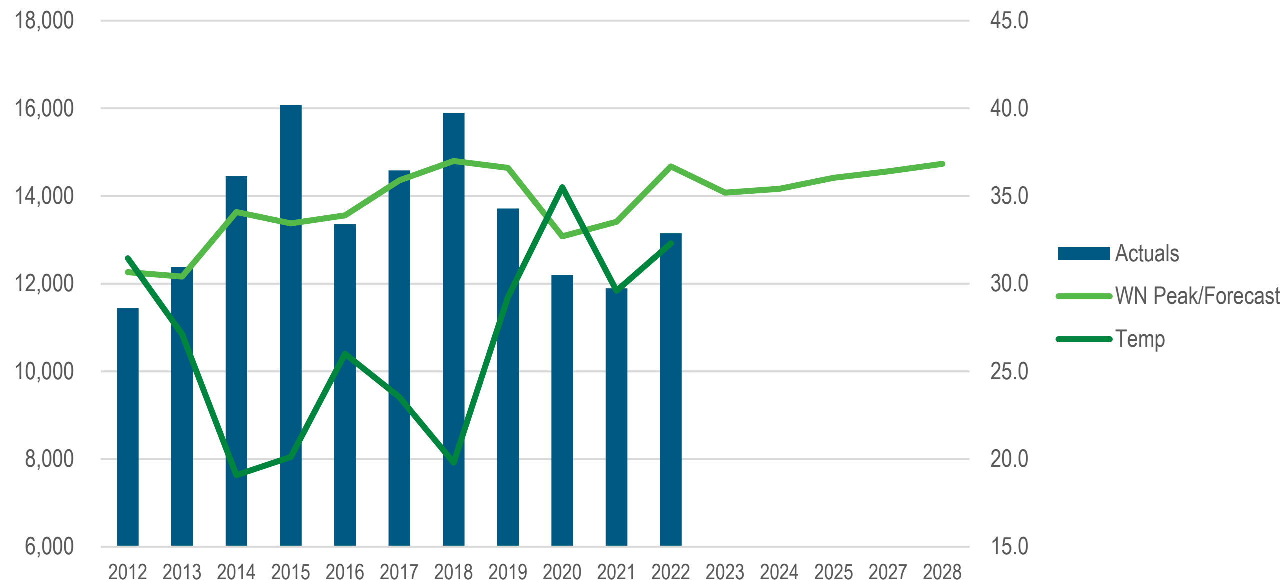
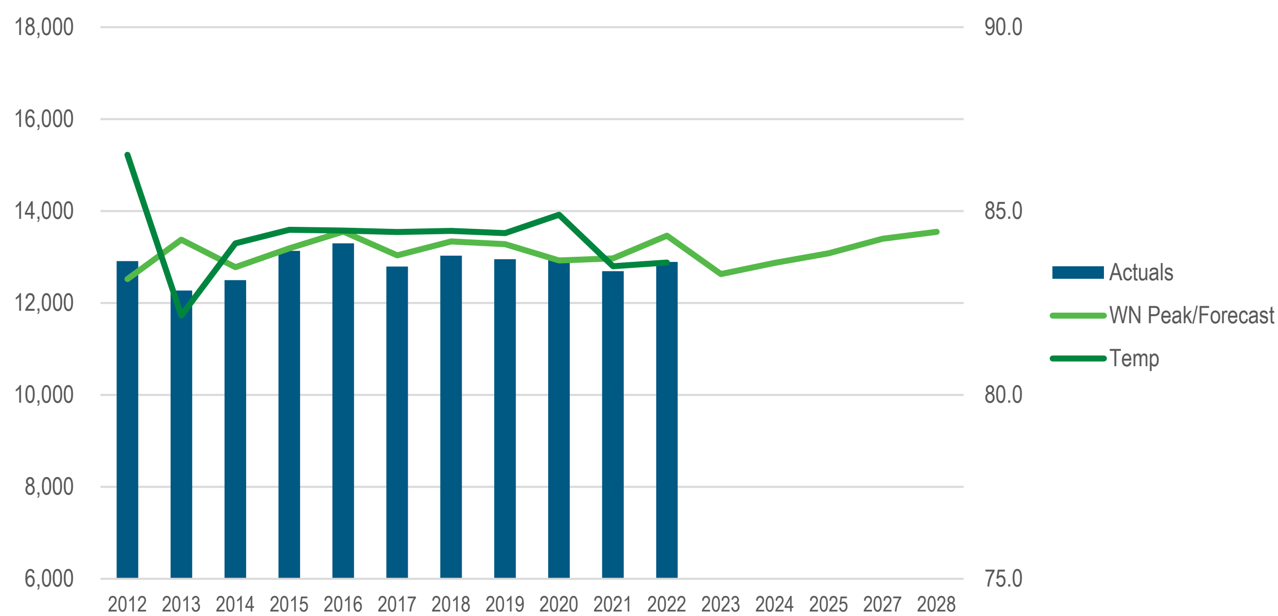


Figure D-14: DEP Actual and Weather Normal and Forecasted Summer Peaks



The following Tables D-21 and D-22 below provide projected peak demand and energy information both with and without the inclusion of EE programs. Figures D-15 and D-16 below provide DEC and DEP load duration curves.

Table D-21: Projected DEC MWh Peak Demand

	Load Forecast without Energy Efficiency Programs (at Generation)			Load Forecast with Energy Efficiency Programs (at Generation)		
YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2024	18,211	17,597	96,580	18,079	17,510	95,767
2025	18,319	17,699	97,199	18,107	17,527	95,857
2026	18,529	17,893	98,219	18,237	17,631	96,351
2027	18,856	18,185	99,904	18,486	17,832	97,516
2028	19,282	18,612	102,230	18,836	18,129	99,315
2029	19,663	19,038	104,515	19,140	18,490	101,069
2030	20,031	19,349	106,610	19,429	18,718	102,640
2031	20,474	19,785	108,863	19,799	19,076	104,393
2032	20,877	20,228	111,224	20,135	19,448	106,293
2033	21,351	20,615	113,562	20,564	19,788	108,310
2034	21,630	20,865	115,328	20,812	20,006	109,876
2035	21,935	21,181	117,274	21,107	20,299	111,672
2036	22,500	21,467	119,279	21,650	20,568	113,584
2037	22,817	21,812	121,181	21,960	20,910	115,455
2038	23,231	22,147	123,280	22,383	21,255	117,664
Avg. Annual Growth Rate	1.6%	1.5%	1.6%	1.4%	1.3%	1.4%

Table D-22: Projected DEP MWh Peak Demand

	Load Forecast without Energy Efficiency Programs (at Generation)			Load Forecast with Energy Efficiency Programs (at Generation)		
YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)	SUMMER (MW)	WINTER (MW)	ENERGY (GWh)
2024	12,954	14,192	65,860	12,874	14,164	65,435
2025	13,214	14,459	67,480	13,080	14,416	66,781
2026	13,397	14,499	68,316	13,210	14,441	67,333
2027	13,637	14,642	69,188	13,397	14,563	67,915
2028	13,824	14,828	70,435	13,549	14,734	68,880
2029	14,011	15,166	71,753	13,668	15,055	69,928
2030	14,391	15,286	73,115	14,001	15,160	71,029
2031	14,689	15,514	74,235	14,254	15,370	71,905
2032	14,912	15,671	75,326	14,439	15,512	72,777
2033	15,159	15,892	76,326	14,660	15,721	73,633
2034	15,196	16,003	77,278	14,682	15,821	74,498
2035	15,333	16,222	78,340	14,804	16,030	75,479
2036	15,576	16,302	79,493	15,037	16,102	76,566
2037	15,773	16,511	80,535	15,224	16,301	77,563
2038	16,040	16,684	81,632	15,495	16,472	78,668
Avg. Annual Growth Rate	1.5%	1.2%	1.5%	1.3%	1.1%	1.3%

Figure D-15: DEC Load Duration Curve

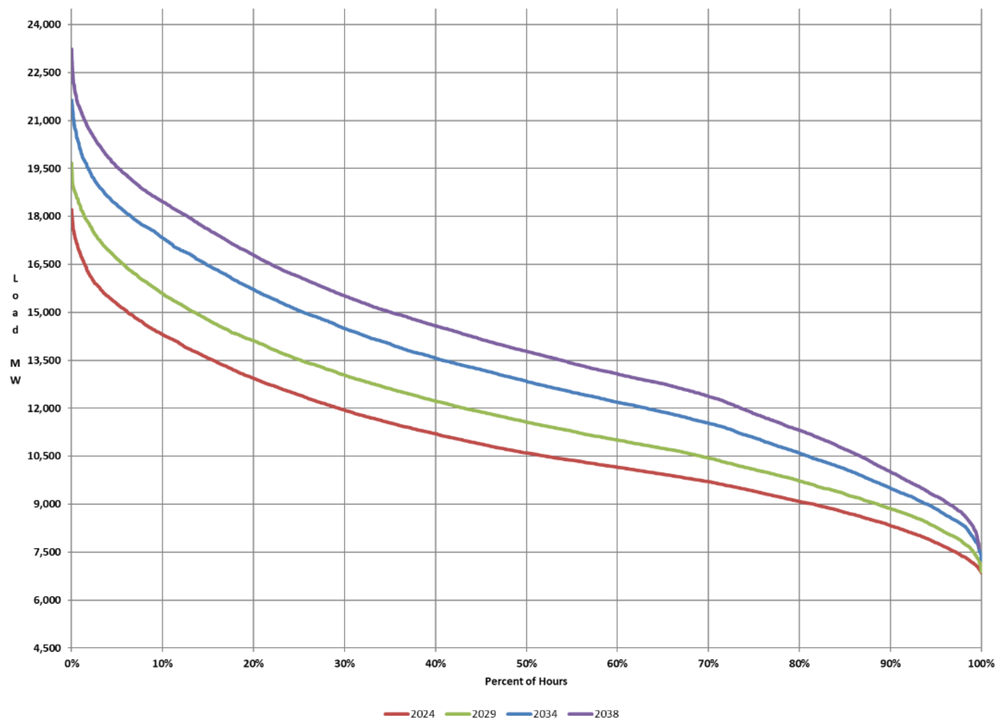


Figure D-16: DEP Load Duration Curve