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Form 4 Demand Forecast Methods and Models

Form 4 is for LSEs to document the electricity demand forecast methods, models, and data used to develop the submitted forecast forms. LSEs may include existing forecast model reports as an appendix to this form if this report includes the following required information.

LSEs should begin Form 4 by defining the area for which the forecast is developed identifying isolated loads and resale customers and describe how they are included or excluded from the forecast. Provide definitions of customer classes, including which rate classes are included in the categories for which forecasts are submitted.

Each of the rate classes for MID's customer consumption is described as follows:

Residential- This schedule is applicable to individual family accommodations devoted primarily to residential, household and related purposes (as distinguished from commercial, professional and industrial purposes), to general farm service on a farm, where the residence on such farm is supplied through the same meter, and to public dwelling units. Service to public dwelling units for residential occupancy is limited by special provisions described in the rate tariff.

Commercial- This schedule is applicable to general commercial customers having a demand of 1,000 kilowatts or less and multiple units for residential occupancy. Service to public dwelling units for residential occupancy is limited by special provisions described in the rate tariff. A demand rate schedule is applied to those customers that are greater than 20 kilowatts. A voluntary time of use rate schedule is also available to commercial customers with a 12 month period of an instantaneous demand of 500-1,000 kilowatts.

Industrial- This schedule is applicable to industrial customers having demands of 1,000 kilowatts or greater in any month during the previous twelve months. For customers above 25,000 kilowatts, a separate industrial rate is available.

Agriculture- This schedule is applicable to separately metered water well pumping, reclamation service, and farm use. Lighting and farm use will be provided to the extent permitted by special provisions as described in the rate tariff. This schedule does not apply to commercial food or agricultural processing operations, machine shops, or any other service not connected with the individual farm operations.

Public Lighting- This Schedule is applicable to all night lighting on the public streets, alleys, highways and parks for cities, lighting districts or other public bodies.

Following is an excerpt from MID's Long-term Demand and Energy Forecast (LTDEF) which describes MID's demand forecast used in this IEPR submittal. This narrative addresses the topics of discussions requested for the 2021 IEPR's Form 4.

Energy Demand and Peak Forecasts

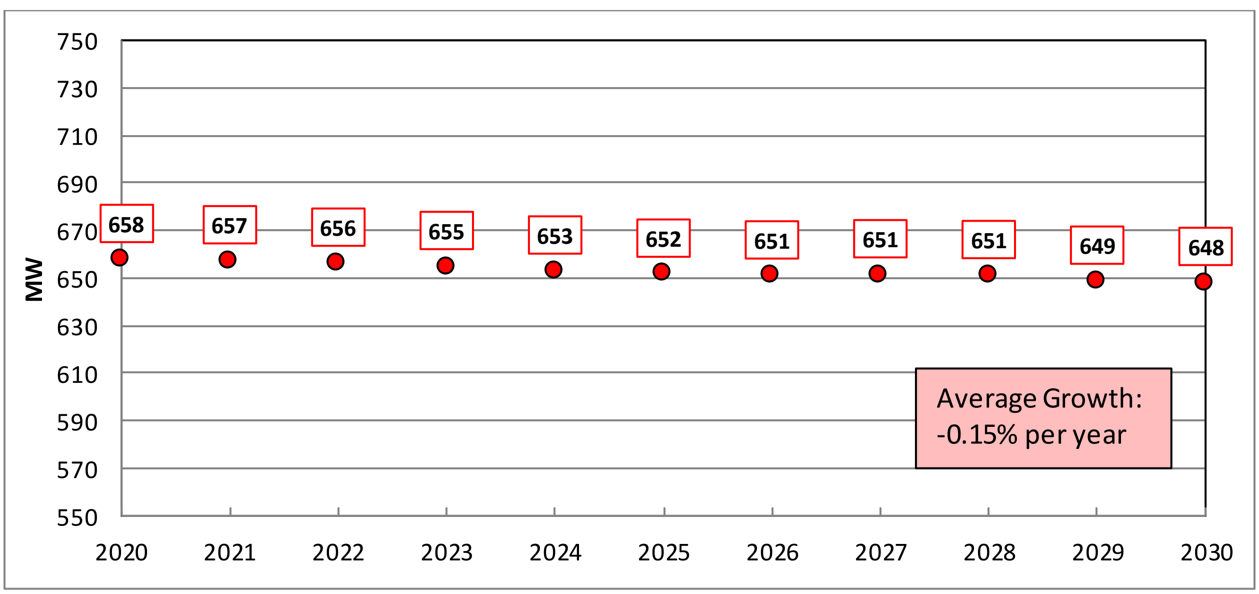
Introduction

The 2020 Long-Term Demand and Energy Forecast (LTDEF) for the MID region and its out-of-MID territory cities[1] (OFT) is discussed in this chapter, including the methodology, assumptions, and data used to create the forecast. The forecast horizon is from 2020 through 2030. A longer forecast through 2040 was developed, and data beyond 2030 can be provided upon request.

The forecast is based on a set of econometric models that describe the hourly load within the region as a function of several weather variables (e.g., surface temperature, solar irradiance), calendar variables (e.g., day of week, holidays), and demographic variables (e.g., Population Data). The LTDEF utilizes regional demographic data obtained from U.S. Department of Labor and the California Department of Finance. Weather data used for the LTDEF is comprised of fifteen years of historical weather data collected by MID. The LTDEF also incorporates demand-side forecast models that include projections for customer solar, energy efficiency, and electric vehicle charging load.

Overview of Forecast Results

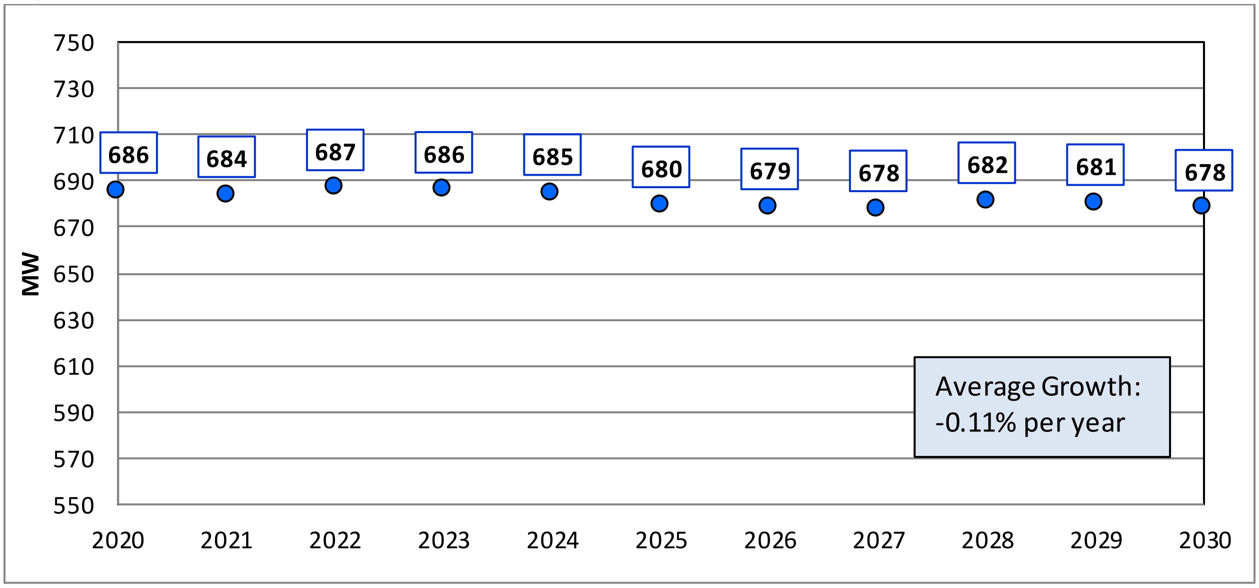
Figure 1-1: MID 1-in-2 System Peak Demand Forecast



[1] Since 1996, MID has served load in competition with PG&E in the northern expansion area, defined as "a 400 square mile area in Southern San Joaquin County, Northern Stanislaus County, and Western Tuolumne County", often referred to as the "four-city area" "including Ripon, Escalon, Oakdale and Riverbank". Additionally, MID has been the sole load serving entity in the city of Mountain House since 2001. MID is also the non-exclusive load serving entity for new load in the northern expansion area, referred as "Greenfield load", since 2007.

As shown in Figure 1-1, the 2020 LTDEF projects that system 1-in-2 non-coincident peak[2] demand will decrease at an average annual rate of approximately -0.15% from 2020 to 2030. Historically, peak demand annual growth increased at a rate of 0.60% from 2010-2019.

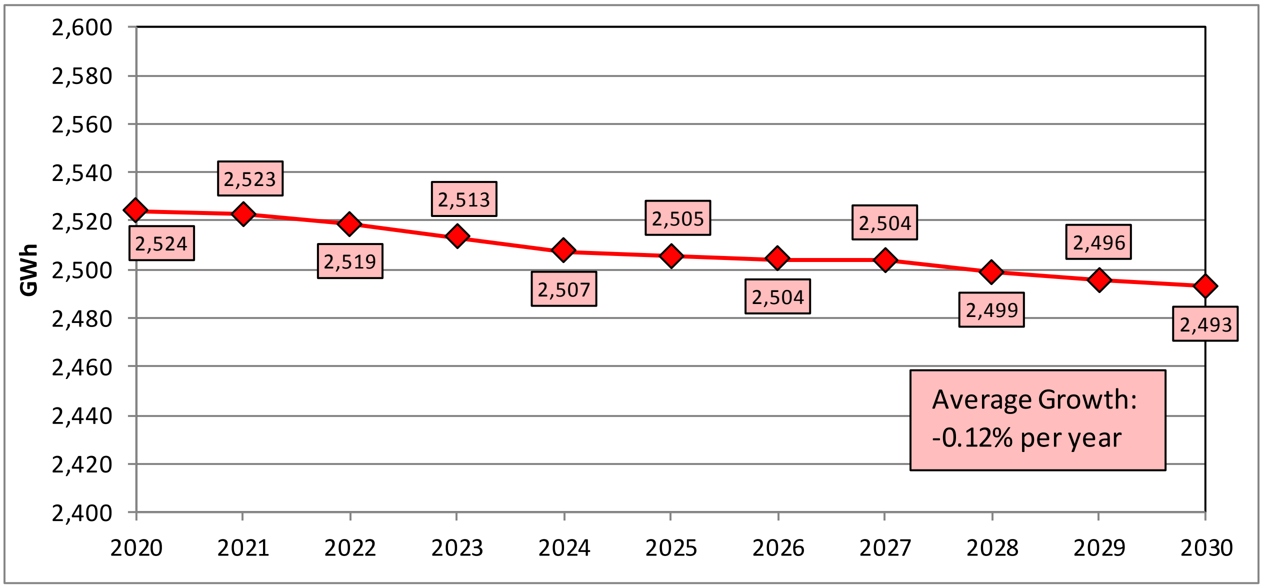
Figure 1-2: MID 1-in-10 System Peak Demand Forecast



As shown in Figure 1-2, the 2020 LTDEF projects that system 1-in-10 non-coincident peak demand will decrease at an average annual rate of approximately -0.11% from 2020 to 2030.

[2] Non-coincident peak: MID's regional peak demand usually does not coincide with the statewide peak demand, so MID only forecasts regional non-coincident peak.

Figure 1-3: MID Forecasted Energy Requirement



As shown in Figure 1-3, the 2020 LTDEF projects system energy will decrease at an average annual rate of approximately -0.12% from 2020-2030. Historically, the average annual energy growth rate was 0.17% from 2010-2019.

2020 LTDEF Methodology and Assumptions

The assumptions and methodology discussed in this chapter reflect MID's current understanding and best estimation of the region, applicable regulations, and technological developments and their impact on energy consumption. All assumptions are subject to change. The annual load forecast update process is designed to capture changes in load conditions due to material changes to any of the several major underlying assumptions in subsequent LTDEF reports. Later chapters in this report will present comparisons of earlier long-term energy forecasts to this 2020 LTDEF. This chapter focuses on the methodology, assumptions, and inputs

Modeling Framework

The 2020 LTDEF is a linear regression model. The model factors in the impacts of weather, economics, demographics, and seasonal trends on energy demand and usage, and also incorporates demand-side forecasts including hourly photovoltaic, energy efficiency, and electric vehicle charging load projections. Impacts of existing interruptible and demand response programs to energy and peak demand forecasts are negligible and are not modeled in the demand side in the LTDEF. Those impacts will be considered in the MID Resource Plan.

The MID LTDEF is comprised of load from two geographic regions: MID base territory and MID OFT. Forecasts for both territories share a similar methodology.

The LTDEF model building process consists of three steps:

- Model variables selection
- Econometric model building process
- Weather scenarios building

Model Variables Selection

The input variables listed below were considered during development of the LTDEF; however, the final model is based only on statistically relevant variables.

- Weather Variables
  - Surface Temperature
  - Solar Irradiance
  - Rainfall (not used in the final model)
  - Humidity (not used in the final model)
  - Lagged Temperature (1-4 hours)
  - 12, 24 & 48-Hour Temperature Moving Average
- Economic and Demographic Variables
  - Population
  - Labor Force Data (not used in the final model)
  - Inflation (not used in the final model)
  - Seasonal Employment (not used in the final model)
- Categorical Variables
  - Month
  - Day Type (day of week, holiday)
  - Hour
- Cross-Reference Variables
  - Temperature and Hour
  - Temperature and Month
  - Lagged Temperature and Hour
  - Lagged Temperature and Month
  - Temperature Moving Average and Hour
  - Temperature Moving Average and Month
  - Hour and Day Type

- Hour and Month

Econometric Model Building Process

During the econometric model building process, historical hourly demand, temperature, economic and demographic data from 1/1/2012 – 12/31/2019 were used. Only the statistically significant variables listed in Section 1.3.1.1. above were selected to build the econometric model.

The initial, "sliding simulation," stage of building the forecast model involved running a set of regressions using historical data. All variables were regressed with actual values that functioned as either independent variables or cross-related variables (X variables). Load from years 2013 to 2018 functioned as the dependent variable (Y variables). These three rolling test result years (2017-2019) were projected using actual data from the four years preceding the test year. By benchmarking the regression's projected Y variable to the actual load of those years (2017-2019), the X variables that had material impact to the resulting projections were identified. Any immaterial X variables were excluded from the model. For example, rainfall data was determined to be an immaterial variable in the econometric model and was excluded. After multiple sliding simulations and additional testing, the statistically relevant variables were used to build a preliminary econometric model.

In the second stage of building the econometric model, a series of rolling regressions were conducted to determine the best regression period. The results of the rolling regressions were then benchmarked to the actual load. The final forecast was developed by using the econometric model and the associated coefficients that were derived from the most recent four-year period. Using the most recent historical data is consistent with the intuitive hypothesis that the current year's electricity consumption pattern will have the most similarities with its most recent historical years.

Table 1-1 below demonstrates the test result year's relationship to its sliding regression data.

Table 1-1: Simulation Years and Forecast Years

O - Test Result Year		**Econometric Model Simulation Years**								
X - Historical Regression Data		Year$_1$	Year$_2$	Year$_3$	Year$_4$	Year$_5$	Year$_6$	Year$_7$	Year$_8$	Year$_9$
Forecast Model	Regression$_1$	**X**	**X**	**X**	**X**	**O**				
	Regression$_2$		**X**	**X**	**X**	**X**	**O**			
	Regression$_3$			**X**	**X**	**X**	**X**	**O**		
	Regression$_4$				**X**	**X**	**X**	**X**	**O**	
	Regression$_5$					**X**	**X**	**X**	**X**	**O**

The final econometric regression model was then fitted and adjusted for data abnormalities. For example, in this version of the econometric model, manual adjustments were necessary to properly account for holidays and to remove time-related forecast errors.

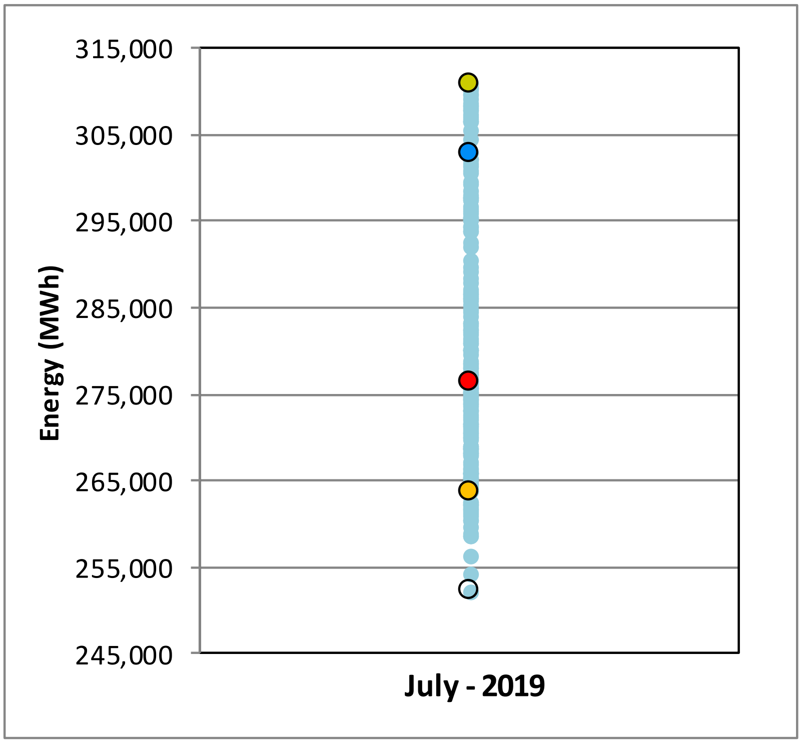
Weather Scenarios Building

After constructing the final econometric regression model, weather scenarios were used to derive the final energy and peak load forecasts. The weather scenarios used in MID's LTDEF model are based on 15 years of historical weather data (1/1/2005-12/31/2019). This historical data was used to create 210 independent weather scenarios. The weather scenarios were created by shifting the base 15-year hourly weather data by 24-hour intervals per scenario set. In total, six lagging scenario sets and seven leading scenario sets were used in addition to the original scenario set. This "weather shifting" was used to capture more variation between weather events and time-series variables such as: day of the week, holidays, and month.

For each forecast year (2020-2030), the 210 historical weather patterned scenarios were entered into the econometric regression model to generate approximately 4,410 sets of load forecasts. The resulting load forecasts were then fitted and adjusted for special days (holidays) and combined with demographic growth to derive each forecast year's final energy and peak demand projection. The result that represents the 50th percentile value of that year's weather patterned model results was selected as the final energy forecast. Each year's 1-in-2 peak demand forecast is the 50th percentile value of that year's weather patterned peak demand model results, and each year's 1-in-10 peak demand forecast is the 90th percentile value of that year's weather patterned peak demand model results.

Table 1-2 uses July 2020 as an example that shows how the monthly energy forecast was derived. After ranking the forecast results from the 210 weather scenario sets from highest to lowest, the monthly energy value of 276,539 MWh was shown to represent the 50th percentile result.

Table 1-2: Energy Forecast Sample



Percentile	Energy
Maximum	310,964
90th Percentile	302,975
50th Percentile	276,539
10th Percentile	263,762
Minimum	252,248

OFT Load Forecast Scenarios

OFT (Out of Territory) load represents a small portion of MID's total demand. Due to lack of historical metered data, the OFT load forecast was derived from 2008-2017 end-of-year billing data for individual cities and their billed rate classes.

Historically, the northern expansion area represents 8.4% of MID's total retail sales and Mountain House represents 1.6% of MID's total retail sales. The ratio of OFT load to the system total load changes over time, but the difference is considered negligible and is not varied in this forecast. Later chapters of this report present detailed monthly and yearly forecasts for the OFT load.

Greenfield load is also considered in the forecast at the same growth rate of the entire system. It accounts for approximately 2% of MID retail load.

Economic Assumptions and Demographic Data

During variable testing, several economic and demographic variables were evaluated: population, labor force, inflation, and seasonal employment. The most significant variable was determined to be population, which was reported by the California Department of Finance. The population data is comprised of population statistics from cities located within the MID region and OFT area. The monthly population data was distributed evenly throughout the entire month and then applied to the econometric model. Population data forecasts are not available, so it is assumed that the population will increase at a rate equal to the average historical growth rate of the past 5 years (2015-2019). This population data was added to the econometric model as an independent variable.

Retail Sales Forecast and Retail Class Forecast

The retail sales forecast was projected by assuming a fixed average transmission loss factor in MID's electric system. The loss factor used in the 2020 LTDEF was based on the average historical loss factor calculated as the difference between the system total input energy and total retail sales. This method results in a loss factor of approximately 2.5%.

Retail class forecasts were derived from historical billing ratios, which are the ratios of historical billed demand in each retail class to total retail load. The set of average historical billing ratios was applied to the 2020 LTDEF retail forecast to derive a retail forecast for each class. The monthly and annual ratios vary, but overall each retail class maintains a consistent ratio over time.

Forecast for Electric Vehicles, Customer Solar, and Energy Efficiency

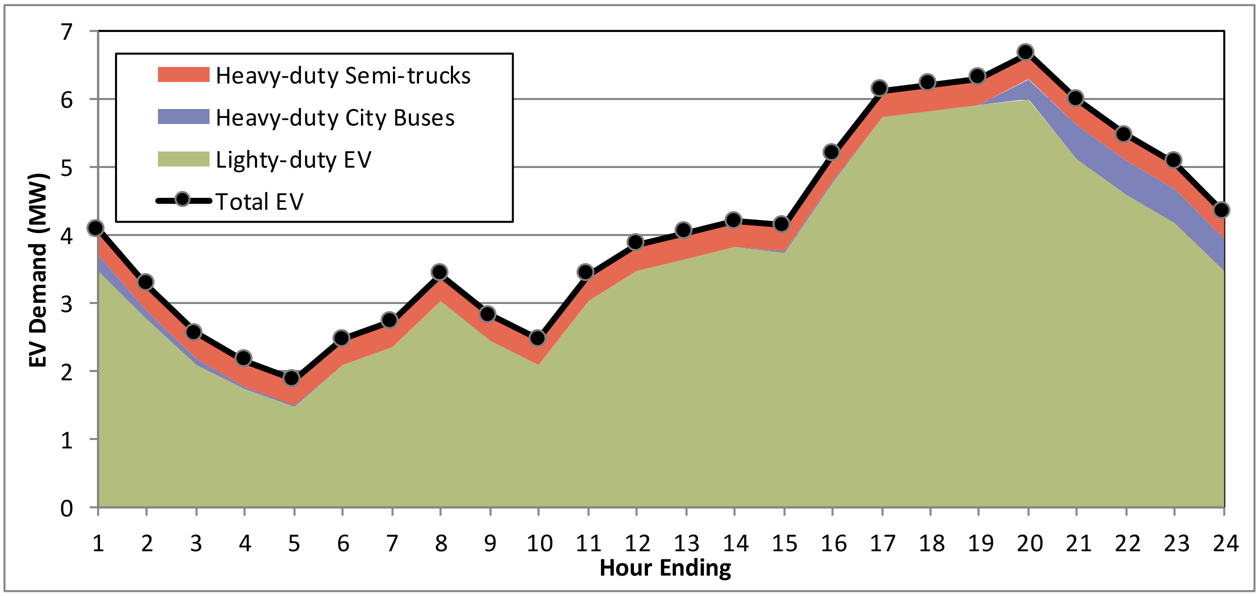
The 2020 LTDEF incorporates two electric vehicle forecasts: light-duty and heavy-duty EVs. Similar to the 2019 LTDEF, the light-duty electric vehicle forecast was developed from methods used in the California Energy Commission's electric vehicle forecast and assumptions, which were published in December 2018 in the, "Light-Duty Plug-in Electric Vehicle Energy and Emission Calculator". The CEC's calculator forecast is derived from a set of base assumptions such as MID's share of California's electric vehicles and the number of projected electric vehicles within California by 2030. MID expects that 0.29 % of electric vehicles will be located within its territory, an increase of 0.13% from the 2019 LTDEF estimation. The 2020 LTDEF predicts that there will be 3.7 million electric vehicles in California by 2030; this assumption aligns with the CEC's projections[3] published in June, 2019. The heavy-duty EV forecast includes energy from two new EV projects occurring in MID's territory: the City of Modesto's bus electrification, and Frito Lay's conversion to electric semi-trucks.

This year's EV forecast indicates significantly greater growth than MID's 2019 LTDEF. The increased growth is driven by a larger share of statewide EVs in MID's territory and higher expectations of statewide plug-in electric vehicle penetration. By the end of 2030, the projected electric vehicle (EV) contribution to MID's load is projected to be 37.1 GWh, a 20.7 GWh increase over the 2019 LTDEF.

[3] (2019, June 14). Retrieved from https://www.energy.ca.gov/sites/default/files/2019-12/3-Mark Palmere_Regional Light-Duty Plug-In Electric Vehicle Forecast 06.14.19_ada.pdf

To incorporate the light-duty forecast EV energy into the load forecast, light-duty charging was shaped into an hourly forecast using a pattern developed from a study by the Rocky Mountain Institute[4]. Heavy-duty charging from semi-trucks was applied equally across all hours while bus charging was based on the City of Modesto's historical charging data. Figure 1-4 is an example of the 24-hour pattern used.

Figure 1-4: July 2030 Electric Vehicle Charging Pattern



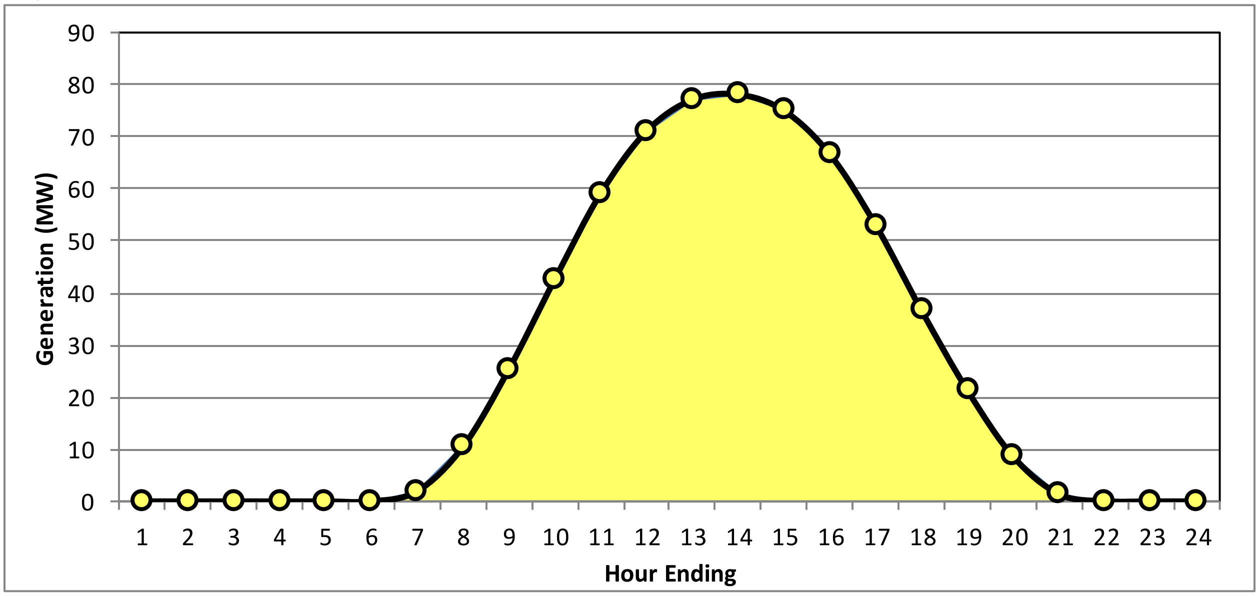
Distributed solar is expected to have a greater impact on MID's energy demand in the 2020 LTDEF than was projected in the 2019 LTDEF. This change is driven by a more aggressive solar capacity forecast due to California's "2019 Building Energy Efficiency Standards" regulation which requires all homes built during or after 2020 to include rooftop solar, and higher-than-predicted participation in MID's Net Energy Metering (NEM) 2.0 program. The 2020 LTDEF's hourly solar forecast is based on a solar generation pattern derived from historical data from a sample of 14 of MID's residential customer solar installations. The solar generation data is used to generate an annual hourly solar profile to represent MID's total installed distributed solar generation. The 2020 LTDEF projects that customer solar generation will offset 160.5 GWh of system energy consumption annually by the end of 2030. This is approximately a 9.5 GWh increase from 2019's estimation.

The hourly solar generation profile was developed using historical information from solar installations located within MID's territory and a modeled distribution pattern of panel orientation created from a random sample of 14 solar systems. As a result, the solar pattern used is representative of approximately 50% south facing, 25% west facing, and 25% east facing capacity. While this distribution

[4] Rocky Mountain Institute, 2016, "Electric Vehicles as Distributed Energy Resources".

is likely an accurate model of MID's system, future improvements to this model will likely include deriving the hourly Behind-the-Meter (BTM) solar forecast from a full set of individual BTM meter data. Figure 1-5 shows the modeled distributed solar generation profile for MID's system in July.

Figure 1-5: July 2030 Behind-the-Meter Solar Pattern



The 2020 LTDEF uses the latest energy efficiency program forecast approved by the MID Board of Directors. The base EE forecast is consistent with MID's 2019 spring Energy Efficiency forecast submitted to the CEC. An hourly profile for energy efficiency programs, which is similar to the profiles published in the 2016 CEC staff report CEC-200-2017-007.