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Valley Clean Energy Alliance

2019 Integrated Energy Policy Report

Electricity Demand Forecast Filling

Form 4 – Demand Forecast Methodology

Submitted

April 15, 2019

Forecast Process

The method used for the 2019 VCEA IEPR Electricity Demand Forecast submittal is described in the 8 steps listed below. Note that VCEA's 2020 resource adequacy forecast is equal to year 2020 of the IEPR demand forecast.

1. Process Historical Customer Interval Meter Data

The VCEA demand forecast begins by evaluating historical retail meter interval data provided from PG&E as "Item 17" data. For this forecast, interval data for the period 2015 - 2018 was analyzed.

2. Develop Average Customer Load Profiles by Rate Class

For the interval data history, customer counts varied over the period for two reasons:

1. The interval data set did not contain 100% of all PG&E customers in the VCEA territory, and for any given customer, a complete time series of interval data across the historic period may not have existed;
2. Customer growth: generally over the period, customer counts increased due to new locations taking electric service.

For the four-year period of interval data history, for each rate class, average per customer loads were developed by dividing the total load for each rate class by the number of customers in that rate class to develop an average hourly load per customer/per class load profile.

Specifically, for the 2015 – 2017 interval data, for each rate class, per customer hourly loads were determined using all load data for all PG&E customers in the VCEA service area. For 2018, for each rate class, the per customer VCEA loads were developed using a subset of the Item 17 interval data from PG&E, filtered based on VCEA customers as identified in the customer information data provided by PG&E ("4013" data) as of January 15, 2019. Service point information for VCEA customers from the 4013 report was used to match to the interval data.

Customers were categorized by rate class using PG&E's ERRA rate class categories. Table 1 below shows those categories.

Table 1. PG&E Rate Classes

Residential (Non TOU)
Residential TOU
Small Commercial (Non TOU)
Small Commercial TOU
Medium Commercial
Street Lighting
Traffic Control
Agricultural
E19 S (Large Commercial/Industrial, Secondary Voltage Service)
E19 P (Large Commercial/Industrial, Primary Voltage Service)
E20 P (Very Large Commercial/Industrial, Secondary Voltage Service)
E20 S (Very Large Commercial/Industrial, Primary Voltage Service)

Rate classes were further split into enrolled VCEA customers versus eligible customers on net energy metering prior to VCEA's launch. For this forecast, the latter group is assumed to be mass-enrolled on a monthly basis in 2021 (see the section below on Additional Mass Enrollments). Separate rate class-specific load profiles/forecasts were developed for this subset of customers in order to separately model their roll-in in 2021. Ineligible (such as direct access) customers were excluded.

3. Weather Normalize the Load Profiles by Rate Class (Weather Adjustments)

The load profiles were weather normalized by developing regression models for each rate class. The weather variables included daily cooling degree days (CDDs) with base temperatures of 65°F, 70°F, and 75°F, heating degree days (HDDs) with base temperatures of 65°F and 60°F, and a non-linear weather response "s" shaped curve for daily high temperatures above 90 degrees Fahrenheit. Daily lagged HDDs and CDDs variables were also specified in the regression models to account for the thermal mass in the building shell.

A daily weather pattern for the forecast expected weather conditions was then developed. Weather data for the VCEA service area comes from the Davis 2 WSW Experimental Farm weather station. Daily high and low temperatures are available from the NOAA FTP web site for weather station USC00042294. To develop the normal weather temperature pattern, daily high and low temperatures from 1996 to Sept 2017 were averaged by date (for example, for Jan 1, Jan 2……Dec 31) to produce a normal weather year. Because of the diversity of the daily high and low temperature over the historical period, averaging over the day of the month does not ensure that the monthly maximum and minimum will be reflected in the normal weather year. Therefore, an adjustment is made based on the construction of a "temperature duration curve" which reflects the maximum and minimum daily temperatures that are expected to occur for each month.

The normal weather pattern is then applied to the regression models for each rate class to obtain the 8,760 hour per customer load shape.

4. Forecast Customer Growth by Rate Class (Economic and Demographic Data)

The actual and forecasted economic and demographic data was produced by the Sacramento Area Council of Governments (SACOG)[1]. The SACOG information included area population, housing and jobs forecasts disaggregated into the Davis, Woodland and unincorporated Yolo county areas. The economic and demographic forecasts were developed at the parcel level for SACOG's 2016 Metropolitan Transportation Plan and Sustainable Community Strategy. The forecasted data was updated in May 2018.

The table below shows the population, housing and jobs forecast for the VCEA service territory.

Table 2. Growth Rates for VCEA Service Area

Forecast Factor	2012 Actual	2036 Forecast	Annual Growth Rate, %
Population	144,539	178,115	0.9%
Housing	54,304	64,498	0.7%
Jobs	65,153	87,251	1.2%

The starting point for the customer forecast was based on the number of VCEA customers from the PG&E 4013 report as of January 15, 2019. This report listed both the VCEA and non-VCEA (PGE bundled service or direct access) customers in the VCEA service territory. For VCEA customers, the growth rates were applied to the January 2019 customer count to produce the customer forecast from 2020 to 2030.

The housing growth annual rate of 0.7 percent was used to forecast the number of customers for the residential, streetlights and traffic signal rate classes. The annual jobs growth rate of 1.2 percent was used to forecast the number of customers for the small, medium, and E19S customer classes.

The customer counts in the E19P, E20S, E20P, and agriculture rate classes was kept constant at their 2019 levels due to lack of information and uncertainty regarding their growth over the forecast period.

[1] For additional information, see SACOG Data Library, City and County Profiles, Updated May 2018, https://www.sacog.org/data-library

Customer counts were adjusted monthly to produce a monthly forecast of customer counts over the forecast horizon.

5. Apply Calibration Factors

The forecast calibration was based on the average monthly sales, by class, from 2015-2017. The forecasted hourly retail loads were summed for each year to produce annual sales per account. The resulting annual sales were then compared to average annual billed energy from 2015-2017. The relative difference between the billed energy and forecasted sales resulted in scaling factors that were used to adjust the weather-normalized sales.

6. Apply Rate Class-Specific Customer Load Profiles to Customer Forecasts

The modeled/normalized per customer rate class-specific load profiles were applied to the rate class-specific customer forecasts to develop the hourly retail load forecast by rate class.

7. Make Additional Adjustments for Net Metered Solar Installations and Plug-In Electric Vehicle Charging Loads

Growth in two known load/usage modifiers were separately modeled in this load forecast: 1) Net energy metered solar installations in residences and 2) Plug-in electric vehicle adoptions and the charging load impacts. Each is described in detail in sections below.

8. Apply Distribution Losses

Up to this point in the process, all loads forecasted are retail loads as measured at the customer meters. Monthly distribution loss factors were applied to the hourly loads to develop a “wholesale” load, excluding transmission losses.

PG&E provides historical hourly distribution loss factors for primary and secondary voltage service customers. Hourly loss factor data for 2015 – 2018 were pulled and averaged to create monthly factors by service level voltage. The percentage of VCEA load forecast to be served for secondary and primary service level voltages was then applied to the factors to develop a composite monthly factor. The factors are shown in Table 3 below.

Table 3. PG&E Distribution Loss Factors

Month	Primary Voltage DLF	Secondary Voltaget DLF	Weighted Composite Distribution Line Loss
	2.4%	97.6%	100%
1	1.0189141455	1.0683812147	6.722%
2	1.0187056567	1.0679898403	6.683%
3	1.0185791085	1.0677817655	6.662%
4	1.0185078285	1.0676985010	6.654%
5	1.0193219308	1.0691536552	6.798%
6	1.0215500969	1.0738228753	7.259%
7	1.0225374059	1.0759258626	7.467%
8	1.0221101884	1.0749418677	7.370%
9	1.0212024356	1.0730372389	7.182%
10	1.0192600838	1.0690515457	6.788%
11	1.0185591130	1.0677586463	6.660%
12	1.0190691931	1.0686570596	6.749%
Average Ar	1.0198597656	1.0703500061	6.916%

The weighted composite monthly distribution line losses were then added to the hourly retail load forecasts to obtain hourly wholesale loads.

Additional Mass Enrollments

Approximately 7,000 PG&E bundled service customers that had net metered distributed generation installations at the time of VCEA's launch in 2018 were not initially enrolled into VCEA service. They are currently planned for mass enrollment into VCEA service during 2021 on the schedule of their annual true-up cycle with PG&E, spreading their enrollment almost evenly across 2021. Existing opt-out rates by customer class for VCEA were applied to this set of PG&E NEM customers in developing the forecast load impacts of their mass enrollment.

The 2020 VCEA forecast assumes there are no mass customer enrollments occurring during 2020.

Customer Migration/Opt-Outs

Opt-outs are as shown in Table 4 below. For the VCEA forecast, opt-out rates are implicitly assumed to remain at the current opt-out percentages, by rate class. No explicit opt-out percentage is applied to customer growth assumptions because customer growth for the VCEA forecast is applied to the base of existing VCEA customers (that excludes customers who have opted out).

Table 4. Opt-Outs by Customer Class

Rate Class	% of Customers Opting Out
Residential (Non TOU)	9%
Residential TOU	9%
Small Commercial (Non TOU)	7%
Small Commercial TOU	31%
Medium Commercial	8%
Agricultural	12%
E19 S	7%
E19 P	0%
E20 S	0%
E20 P	25%
Streetlighting	9%
Traffic Control	0%

New Net Energy Metered Distribution Generation Adoption

VCEA's service area has a fairly high adoption rate of net energy metered solar installations. From January 2018 to January 2019, 956 residential customers in VCEA's service area installed net energy metered distributed generation at existing service locations. We extrapolated that growth into the future and assumed that 1,000 VCEA customers would install net energy metered solar for each year of the forecast horizon. To simplify the modelling, it was assumed that these installations would all be in residences.

The number of existing residential customers installing net energy metered solar was then forecast separately by month, which was then applied to a residential net energy metered load profile to produce a net energy metered adoption subclass forecast. The counts of customers in the growing residential net energy metered subclass were deducted from the forecast of non-net energy metered residential customers to model the reduction in non-net energy metered residential load and increase in net energy metered residential loads that resulted.

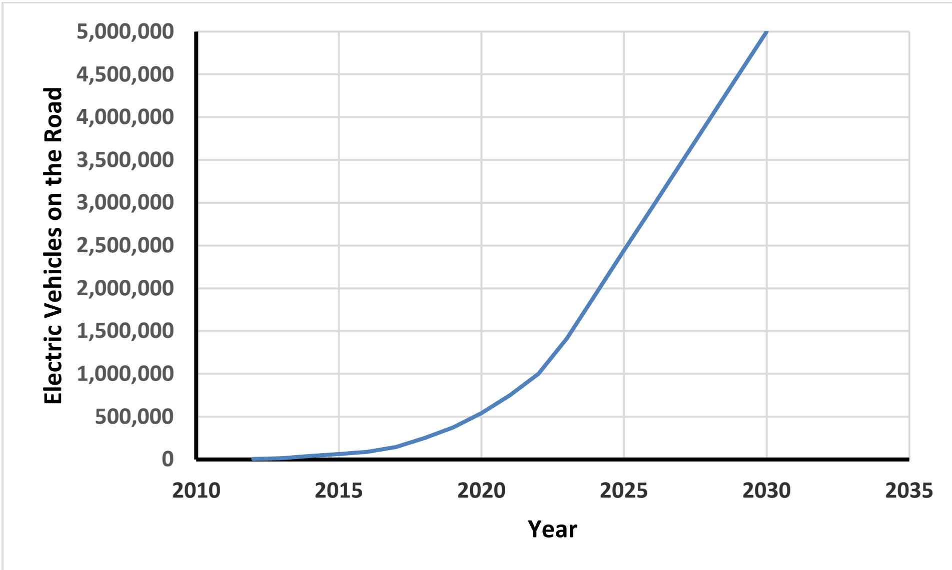
Plug-In Electric Vehicle Charging Loads

Adoption of electric vehicles (EVs) is increasing. Over time, we expect the vehicle charging loads to be significant. The California Air Resources Board, in its 2017 Climate Change Scoping Plan[2] identified a statewide target of needing 5 Million electric vehicles on the road in order to meet 2030 carbon emission reduction goals. To convert

[2] *California's 2017 Climate Change Scoping Plan, The Strategy for Achieving California's 2030 Greenhouse Gas Target*, California Air Resources Board, November 2017, https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf

that goal into an EV forecast, we developed an adoption curve for statewide EV counts from 2010. That curve is shown in Chart 1 below.

Chart 1. Statewide EV Adoption Curve



To convert the statewide forecast to an EV adoption forecast for VCEA, the number of statewide vehicle adoptions were prorated to VCEA using comparisons of current (January 2018) population statewide, versus population in VCEA's service area. 0.40% of the state's population resides in VCEA's service area.

EV counts were then applied to residential EV charging curves developed by NREL, as published in the California Energy Commission's report on plug-in electric vehicle charging infrastructure[3]. To simplify modelling, we assumed all charging would be done in residences, which has an evening/nighttime weighted charging shape.

Energy Efficiency and Demand-Side Management

In this first IEPR load forecast, we did not attempt to model the impacts of future energy efficiency and demand-side management programs, as those programs are currently managed by PG&E. VCEA does not have enough information on those programs or their estimated impacts to properly factor them into this 2019 IEPR forecast.

Climate Change and Electrification

The impacts of climate change were not modelled in this VCEA 2019 IEPR forecast. To do so would require a model of how local weather and daily temperatures would

[3] California Plug-In Electric Vehicle Infrastructure Projections: 2017-2025, Future Infrastructure Needs for Reaching the State's Zero-Emission-Vehicle Deployment Goals, California Energy Commission, March 2018, CEC-600-2018-001, https://www.nrel.gov/docs/fy18osti/70893.pdf

change, in order to construct a “normal” weather profile with increasing average temperatures going forward in time.

Apart from vehicle electrification, the possible future impacts of other electrification, such as space and water heating, were not modelled.