California Energy Commission

DRAFT STAFF REPORT

California Energy Demand 2018-2028 Preliminary Forecast

California Energy Commission

Edmund G. Brown Jr., Governor

August 2017 | CEC-200-2017-006-SD

California Energy Commission

Chris Kavalec
Asish Gautam
Primary Authors

Chris Kavalec
Project Manager

Siva Gunda
Office Manager
DEMAND ANALYSIS OFFICE

Sylvia Bender
Deputy Director
ENERGY ASSESSMENTS DIVISION

Robert P. Oglesby
Executive Director

ACKNOWLEDGEMENTS

The demand forecast is the combined product of the hard work and expertise of numerous staff members in the Demand Analysis Office and Energy Assessments Division. In addition to the contributing authors listed previously, Mark Ciminelli and Kelvin Ke provided the transportation, communications, and utilities and street lighting forecasts, Mohsen Abrishami prepared the commercial sector forecast, Mehrzad Soltani Nia prepared the industrial forecast, and Ted Dang contributed to the residential forecast. Nancy Tran developed the economic/demographic projections, Ravinderpal Vaid provided the projections of commercial floor space, and Glen Sharp prepared the household data. Jelani Williams prepared the weather data and Steven Mac, Cam Nguyen, and Julianne Alontave prepared the historical energy consumption data. Elena Giyenko and Cynthia Rogers developed the energy efficiency program estimates, Doug Kemmer prepared the estimates for demand response impacts, and Miguel Cerrutti created the breakout for individual load-serving entities. The electricity rate scenarios were developed by Lynn Marshall and the natural gas price scenarios by Jason Orta. Jelani Williams ran the Summary Model, and Mitch Tian prepared the peak demand forecast.

ABSTRACT

The *California Energy Demand 2018–2028 Preliminary Forecast* describes the California Energy Commission's preliminary 10-year forecasts for electricity consumption, retail sales, and peak demand for each of five major electricity planning areas and for the state as a whole. This forecast supports the analysis and recommendations set forth in the *2014 Integrated Energy Policy Report Update.* The forecast includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid-energy demand* case. The *high energy demand* case incorporates relatively high economic/demographic growth and climate change impacts, and relatively low electricity rates and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases.

Keywords: Electricity, demand, consumption, forecast, peak, self-generation, conservation, energy efficiency, climate zone, electrification, light-duty electric vehicles, distributed generation, natural gas

Please use the following citation for this report:

Kavalec, Chris and Asish Gautam. 2017. *California Energy Demand 2018-2028 Preliminary Forecast.* California Energy Commission, Electricity Assessments Division. Publication Number: CEC-200-2017-006-SD.

TABLE OF CONTENTS

Page

Acknowledgements i

Abstract ii

Table of Contents iii

List of Figures iv

List of Tables v

Executive Summary 1

Introduction 1

Results 1

Summary of Changes to Forecast 6

CHAPTER 1: Statewide Baseline Forecast Results and Forecast Method 9

Introduction 9

Summary of Changes to Forecast 10

Statewide Results 11

Method 23

Geography 23

Economic and Demographic Inputs 25

Electricity and Natural Gas Rates 31

Self-Generation 33

Conservation/Efficiency Impacts 36

Light-Duty EVs 38

Other Transportation Electrification 40

Climate Change 41

Demand Response 42

CHAPTER 2: Electricity and Natural Gas Planning Area Results 44

PG&E Electricity Planning Area 44

SCE Planning Area 47

SDG&E Electricity Planning Area 50

NCNC Planning Area 52

LADWP Planning Area 55

PG&E Natural Gas Planning Area 57

SoCal Gas Planning Area 59

SDG&E Natural Gas Planning Area 61

LIST OF ACRONYMS 63

APPENDIX A: Self-Generation Forecasts A-1

Compiling Historical Distributed Generation Data A-1
Residential Sector Predictive Model A-6
Self-Generation Forecast, Nonresidential Sectors A-11
Commercial Combined Heat and Power and Photovoltaic Forecast A-11
Other Sector Self-Generation A-14
Statewide Modeling Results A-14
Optional Scenario A-19

LIST OF FIGURES

Page

Figure ES-1: Statewide Baseline Annual Electricity Consumption 3

Figure ES-2: Statewide Baseline Retail Electricity Sales 4

Figure ES-3: Statewide Baseline Annual Noncoincident Peak Demand 5

Figure ES-4: Statewide Baseline End-User Natural Gas Consumption Demand 6

Figure 1: Statewide Baseline Annual Electricity Consumption 14

Figure 2: Statewide Baseline Retail Electricity Sales 15

Figure 3: Statewide Baseline Electricity Annual Consumption per Capita 16

Figure 4: Statewide Baseline Annual Noncoincident Peak Demand 19

Figure 5: Statewide Baseline Annual Noncoincident Peak Demand per Capita 20

Figure 6: Statewide Baseline End-User Natural Gas Consumption Demand 23

Figure 7: Statewide Personal Income 28

Figure 8: Statewide Commercial Employment 29

Figure 9: Statewide Manufacturing Output 30

Figure 10: Statewide Population 31

Table 7: Retail Natural Gas Prices by Demand Case for Three Major Planning Areas (2016 $ per Therm) 33

Figure 11: Statewide PV Capacity 35

Figure 12: Statewide Self-Generation Peak Reduction Impact 35

Figure 13: Statewide Committed Utility Efficiency Program Electricity Savings, 1990-2028 37

Figure 14: Statewide Committed Utility Efficiency Program Natural Gas Savings, 2006-2028 37

Figure 15: Statewide Light-Duty EV Stock 39
Figure 16: Statewide Light-Duty EV Electricity Consumption 39
Figure 17: Historical and Projected Sales, PG&E Planning Area 47
Figure 18: Historical and Projected Sales, SCE Planning Area 49
Figure 19: Historical and Projected Sales, SDG&E Planning Area 52
Figure 20: Historical and Projected Sales, NCNC Planning Area 55
Figure 21: Historical and Projected Sales, LADWP Planning Area 57
Figure 22: PG&E Baseline End-User Natural Gas Consumption Demand 59
Figure 23: SoCal Gas Baseline End-User Natural Gas Consumption Demand 61
Figure 24: SDG&E Baseline End-User Natural Gas Consumption Demand 62
Figure A-1: Statewide Historical Distribution of Self-Generation, All Customer Sectors A-4
Figure A-2: Statewide PV Self-Generation by Customer Sector A-4
Figure A-3: Top 20 Counties With PV by Sector in 2014 .... A-5
Figure A-4: Statewide Historical Distribution of Self-Generation, Nonresidential Sectors A-5
Figure A-5: Statewide Historical Distribution of Self-Generation by Technology A-6
Figure A-6: Distribution of Annual End-Use Consumption by Fuel Type – North Coastal Small/Medium Buildings A-12
Figure A-7: Hourly* Electricity Demand for Large Schools, South Coastal Climate Zones A-13
Figure A-8: PV Generation, Statewide A-15
Figure A-9: Non-PV Generation, Statewide A-16
Figure A-10: Comparison of PV Forecast, PG&E A-17
Figure A-11: Comparison of PV Forecast, SCE A-17
Figure A-12: Comparison of PV Forecast, SDG&E A-18
Figure A-13: PV Adoption From Zero-Net-Energy Home Penetration A-20
Figure A-14: Scenarios for Existing CHP Plants A-21

LIST OF TABLES

Page

Table ES-1: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of Statewide Electricity Demand 2

Table 1: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of Statewide Electricity Demand 12

Table 2: Baseline Electricity Consumption by Sector 17

Table 3: Comparison of CED 2017 Preliminary and CED 2015 Mid Case Demand Baseline Forecasts of Statewide End-User Natural Gas Consumption 22

Table 4: Load-Serving Entities Within Forecasting Planning Areas 24

Table 5: Key Assumptions Embodied in *CED 2017 Preliminary* Economic Scenarios 26

Table 6: Electricity Rates by Demand Case, Five Major Planning Areas (2016 cents per kWh) 32

Table 8: Additional Electrification, Statewide (GWh) 41

Table 9: Estimated Nonevent-Based Demand Response Program Impacts (MW) 43

Table 10: Estimated Demand Response Program Impacts: Critical Peak Pricing and Peak-Time Rebate Programs (MW) 43

Table 11: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of PG&E Electricity Demand 45

Table 12: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of SCE Electricity Demand 48

Table 13: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of SDG&E Electricity Demand 51

Table 14: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of NCNC Electricity Demand 53

Table 15: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of LADWP Electricity Demand 56

Table 16: Comparison of *CED 2017 Preliminary* and *CED 2015* Mid Case Demand Baseline Forecasts of PG&E End-User Natural Gas Consumption 58

Table 17: Comparison of *CED 2017 Preliminary* and *CED 2015* Mid Case Demand Baseline Forecasts of SoCal Gas End-User Natural Gas Consumption 60

Table 18: Comparison of CED 2017 Preliminary and CED 2015 Mid Case Demand Baseline Forecasts of SDG&E End-User Natural Gas Consumption 62

Table A-1: Residential TOU Rates A-8

EXECUTIVE SUMMARY

Introduction

This California Energy Commission staff report presents forecasts of electricity and natural gas consumption and peak electricity demand for California and for each major utility planning area within the state for 2018–2028. The *California Energy Demand 2018—2028 Preliminary Forecast* (CED 2017 Preliminary) supports the analysis and recommendations of the *2016 Integrated Energy Policy Report Update,* including electricity system assessments and analysis of progress toward increased energy efficiency, with goals recently codified in Senate Bill 350 (De León, Chapter 547, Statutes of 2015), and distributed generation.

The Integrated Energy Policy Report (IEPR) Lead Commissioner will conduct a workshop on August 3, 2017, to receive public comments on this forecast. Following the workshop, subject to the direction of the Lead Commissioner, staff will prepare a revised forecast for possible adoption by the Energy Commission. The revised forecast will include an assessment of additional achievable energy efficiency impacts not included in CED 2017 Preliminary.

CED 2017 Preliminary includes three full scenarios: a high energy demand case, a low energy demand case, and a mid-energy demand case. The high energy demand case incorporates relatively high economic/demographic growth and climate change impacts, and relatively low electricity rates and self-generation impacts. The low energy demand case includes lower economic/demographic growth, higher assumed rates, and higher self-generation impacts. The mid case uses input assumptions at levels between the high and low cases. These forecasts are referred to as *baseline cases,* meaning they do not include additional achievable energy efficiency savings.

Results

The CED 2017 Preliminary baseline electricity forecast for selected years is compared with the *California Energy Demand Updated Forecast 2017––2027* (CEDU 2016) mid demand case in **Table ES-1**. Forecast consumption in the CED 2017 Preliminary mid demand case starts out below the CEDU 2016 mid case as additional utility efficiency program impacts are included for the 2016 and 2017 program years. Consumption in the new mid case remains below CEDU 2016 as 2016 updates to the Title 24 building standards (implemented in 2017) accumulate savings and, toward the end of the forecast period, forecast electric vehicle (EV) consumption dips below that in the previous forecast. CED 2017 Preliminary statewide noncoincident weather-normalized peak demand is significantly lower than CEDU 2016 by 2020, reflecting a higher forecast for photovoltaic (PV) systems. PV impacts drive average annual growth in peak demand negative from 2016–2020 in the mid demand case, while annual growth is negative throughout the forecast period in the low demand case.

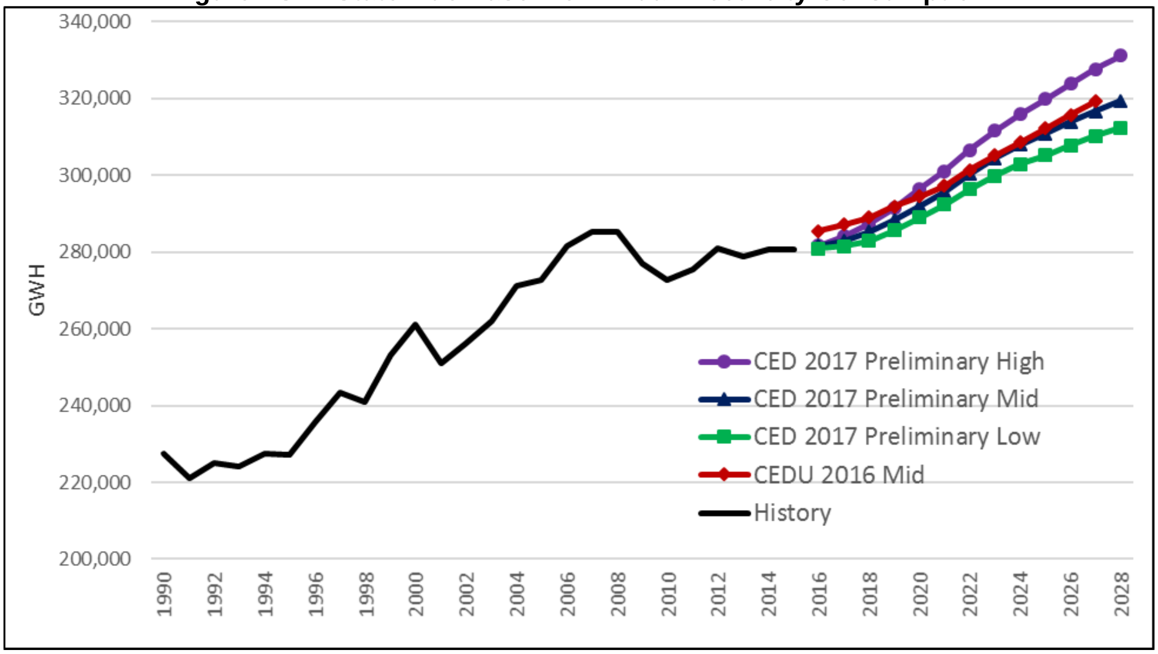
Table ES-1: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	***CEDU 2016* Mid Energy Demand**	***CED 2017 Preliminary* High Energy Demand**	***CED 2017 Preliminary* Mid Energy Demand**	***CED 2017 Preliminary* Low Energy Demand**
1990	227,606	227,593	227,593	227,593
2000	261,036	260,940	260,940	260,940
2015	281,334	281,664	281,666	280,922
2020	294,474	296,369	291,991	288,938
2025	312,223	320,008	310,989	305,383
2027	319,256	327,845	316,850	310,297
2028	--	331,320	319,484	312,500
	Average Annual Growth Rates			
1990-2000	1.38%	1.38%	1.38%	1.38%
2000-2015	0.50%	0.51%	0.51%	0.49%
2015-2020	0.92%	1.02%	0.72%	0.56%
2015-2027	1.06%	1.27%	0.99%	0.83%
2015-2028	--	1.26%	0.97%	0.82%
Noncoincident Peak (MW)				
	***CEDU 2016* Mid Energy Demand**	***CED 2017 Preliminary* High Energy Demand**	***CED 2017 Preliminary* Mid Energy Demand**	***CED 2017 Preliminary* Low Energy Demand**
1990	47,123	47,115	47,115	47,115
2000	53,529	53,521	53,521	53,521
2016*	60,543	60,528	60,527	60,527
2020	61,444	60,964	60,074	59,081
2025	63,075	63,987	61,570	59,203
2027	63,501	64,894	61,855	59,052
2028	--	65,273	61,962	58,964
	Average Annual Growth Rates			
1990-2000	1.28%	1.28%	1.28%	1.28%
2000-2016	0.77%	0.77%	0.77%	0.77%
2016-2020	0.37%	0.18%	-0.19%	-0.60%
2016-2027	0.43%	0.64%	0.20%	-0.22%
2016-2028	--	0.63%	0.20%	-0.22%
Actual historical values are shaded.				
*Weather normalized: the forecasts use a weather-normalized peak value derived from the actual 2016 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2017.

Projected electricity consumption for the three *CED 2017 Preliminary* baseline cases and the *CEDU 2016* mid demand forecast is shown in **Figure ES-1**. In 2027, consumption in the new mid case is projected to be slightly less than 1 percent lower than the *CEDU 2016* mid case, around 2,600 gigawatt-hours (GWh). Annual growth from 2015-2027 for the *CED 2017 Preliminary* forecast averages 1.27 percent, 0.99 percent, and 0.83 percent in the high, mid and low cases, respectively, compared to 1.06 percent in the *CEDU 2016* mid case.

Figure ES-1: Statewide Baseline Annual Electricity Consumption

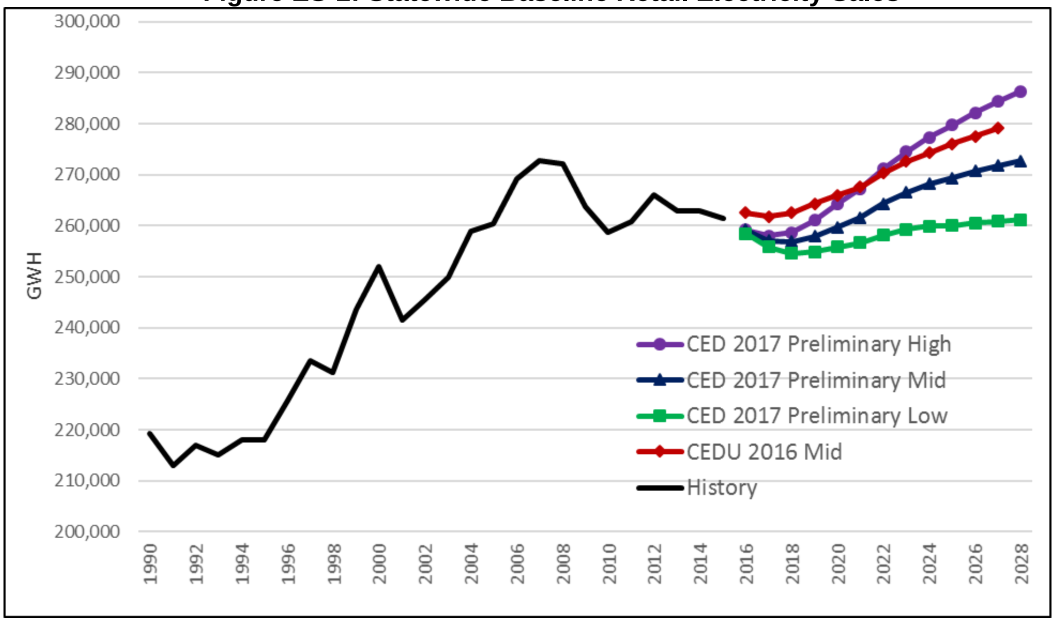


Source: California Energy Commission, Demand Analysis Office, 2017.

The increase in projected consumption met with self-generation in *CED 2017 Preliminary* as a result of more residential PV adoption reduces statewide electricity retail sales by a greater amount compared to *CEDU 2016* than for consumption. Projected statewide sales for the three *CED 2017 Preliminary* cases and the *CEDU 2016* mid demand case are shown in **Figure ES-2**. All three new forecast cases are lower than the *CEDU 2016* mid case at the beginning of the forecast period with the addition of new efficiency program impacts and more PV adoptions, with the new high case pushing above *CEDU 2016* by 2022. By 2027, sales in the *CED 2017 Preliminary* mid scenario are projected to be around 7,300 GWh (2.6 percent) lower than in the *CEDU 2016* mid case. Annual growth from 2015–2027 for the *CED 2017 Preliminary* scenarios averages 0.70 percent, 0.32 percent, and -0.02 percent in the high, mid, and low cases, respectively, compared to 0.52 percent in the *CEDU 2016* mid case.

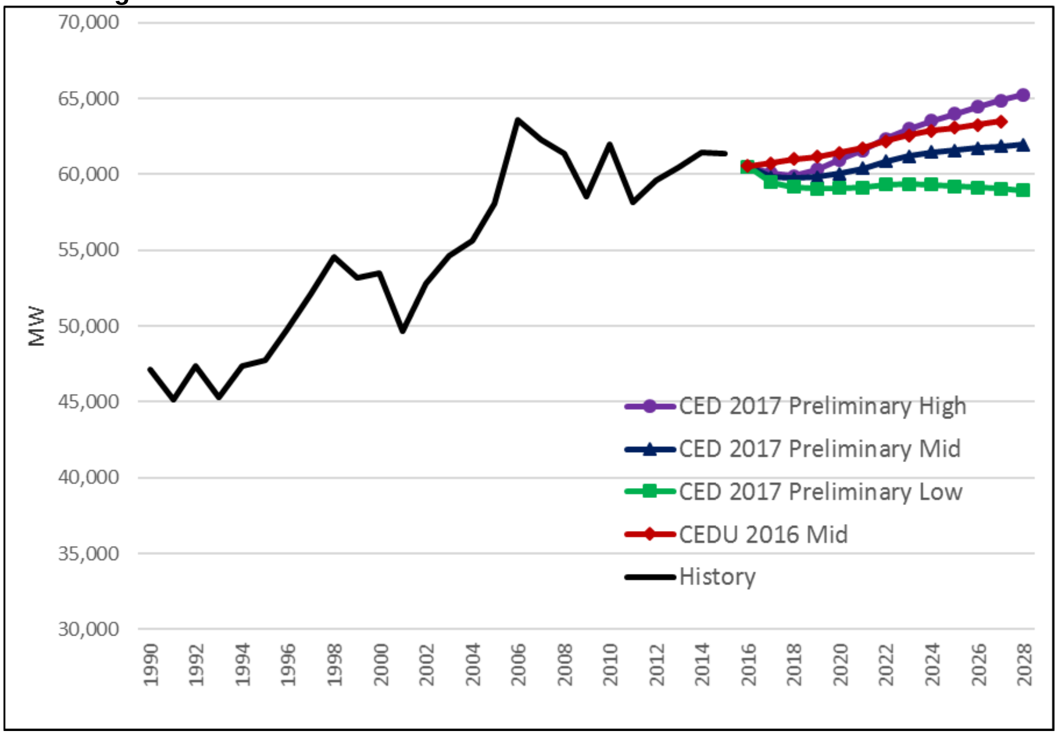
Projected *CED 2017 Preliminary* noncoincident peak demand for the three baseline cases and the *CEDU 2016* mid demand peak forecast is shown in **Figure ES-3** and essentially mirrors electricity sales as shown in **Figure ES-2**. By 2027, statewide peak demand in the new mid case is projected to be 2.6 percent lower than the *CEDU 2016* mid case. Annual growth rates from 2016–2027 for the *CED 2017 Preliminary* scenarios average 0.64 percent, 0.20 percent, and -0.22 percent in the high, mid, and low cases, respectively, compared to 0.43 percent in the *CEDU 2016* mid case. As with sales, higher projected self-generation reduces the growth rate in the new mid case compared to *CEDU 2016*. The lower projections for EVs have relatively less impact on peak demand than consumption and sales, as staff assumes that most recharging occurs in off-peak hours.

Figure ES-2: Statewide Baseline Retail Electricity Sales



Source: California Energy Commission, Demand Analysis Office, 2017.

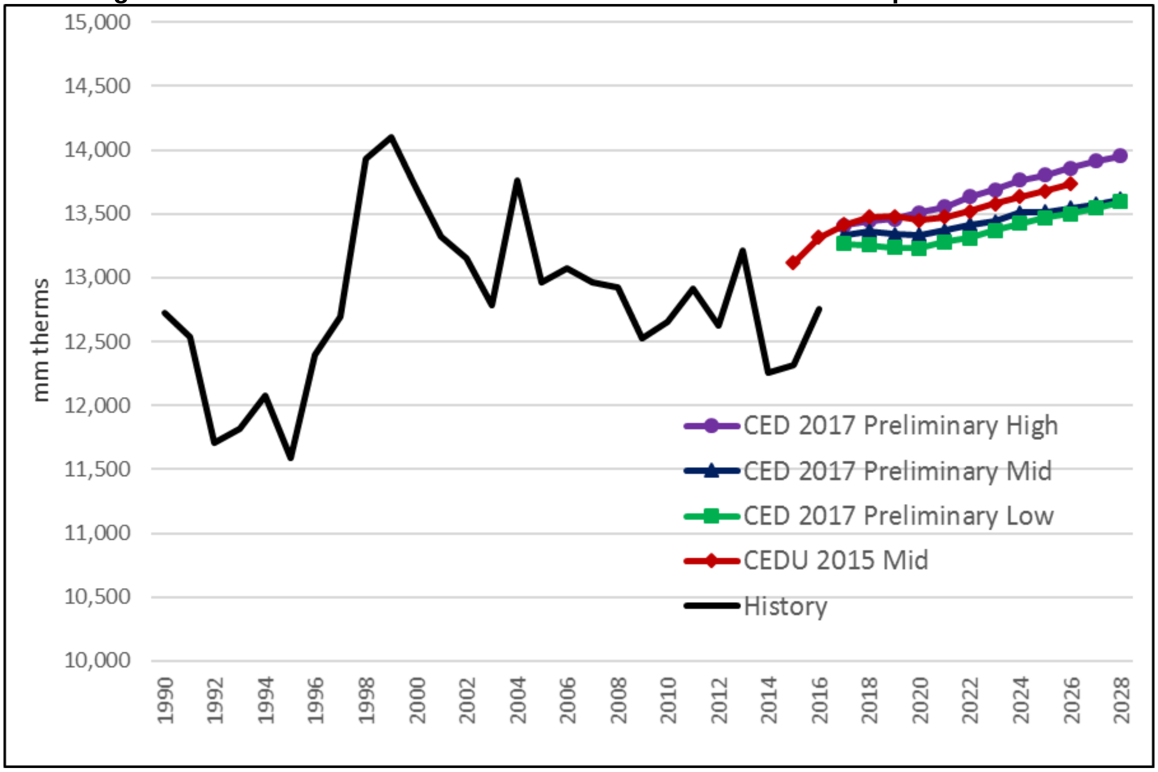
Figure ES-3: Statewide Baseline Annual Noncoincident Peak Demand



Source: California Energy Commission, Demand Analysis Office, 2017.

Statewide natural gas consumption demand for the three *CED 2017 Preliminary* cases and the *California Energy Demand 2016—2026 Revised Forecast* (*CED 2015*) mid case is shown in **Figure ES-4.** The historical series clearly shows the variability in consumption from year to year, with changes in weather being a key contributor to this variability. For the period 2016-2026, annual growth in consumption averages 0.84 percent, 0.61 percent, and 0.57 percent in the high, mid, and low cases, respectively, compared to 0.32 percent in the *CED 2015* mid case. By the end of the forecast period, low case consumption is almost identical to the new mid case, a result of climate change impacts that affect (reduce) the mid case totals but not the low.

Figure ES-4: Statewide Baseline End-User Natural Gas Consumption Demand



Source: California Energy Commission, Demand Analysis Office, 2017.

Summary of Changes to Forecast

CED 2017 Preliminary uses the modified geographic scheme for planning areas and climate zones introduced for *CED 2015*, which is more closely based on California's balancing authority areas. The modified scheme has been more fully integrated into the sector models for this forecast through the inputs, rather than relying on mapping of outputs as in previous forecasts. The results of the Energy Commission's ongoing Title 20 Rulemaking for appliance energy efficiency standards will determine the additional consumption and metered data available from the utilities to support further geographic disaggregation, or breakdown, of future forecasts. Once the data availability becomes clear, Energy Commission staff will work with the utilities to determine an optimal level of disaggregation to better serve transmission and distribution level analyses.

Utility efficiency program impacts have been updated to reflect activity in 2016 and 2017. Expected program impacts beyond 2017 will be incorporated in the revised version of this forecast through additional achievable energy efficiency (AAEE) savings.[1] The 2016 updates to Title 24 building standards are included in *CED 2017 Preliminary*,

1 Additional Achievable Energy Efficiency is defined in Estimates of Additional Achievable Energy Efficiency, Supplement to the California Energy Demand, 2014-2024 Revised Forecast, September 2013, CEC-200-2013-005-SD, http://www.energy.ca.gov/2013publications/CEC-200-2013-005/CEC-200-2013-005-SD.pdf

with future likely standards updates also handled through AAEE estimates. For the investor-owned utilities, estimated AAEE savings will be derived from the California Public Utilities Commission's *2018 Potential and Goals Study*, while estimates for publicly owned utilities will be developed through individual utility adopted goals. "Committed" efficiency savings implemented in 2015–2017 (included in this baseline forecast) plus estimated AAEE savings out to 2030 will constitute the contributions from utility programs, as well as building and appliance standards toward meeting the SB 350 goals. The Efficiency Division of the Energy Commission is investigating additional efficiency savings potential outside utility programs and standards available to meet the goals. Depending on progress made in that analysis, some or all of these estimated additional savings may be incorporated in the revised version of this forecast.

The predictive model for self-generation has been modified so that adoption of residential PV systems is based on monthly bill savings rather than system payback as in previous forecasts. In addition, the model incorporates the impact of residential time-of-use rates on PV system adoption.

CED 2017 Preliminary incorporates a new transportation electricity forecast, which includes light-duty vehicles, medium- and heavy-duty vehicles, public transit, and high-speed rail. Light-duty electric vehicle purchases, which include battery-electric and plug-in hybrid, are projected to be more than sufficient to meet the California Air Resources Board's zero-emission vehicle mandates as modeled in its most recent compliance case.

Energy Commission staff is developing an hourly load forecasting model for the investor-owned utility planning areas, expected to be complete in time for the revised version of this forecast. This model will incorporate hourly PV generation and hourly load impacts of electric vehicles, AAEE, and residential time-of-use pricing. As in the annual forecast, progress to develop this model for additional utilities and load pockets will depend on the outcome of the current Title 20 data regulations rulemaking

CHAPTER 1: Statewide Baseline Forecast Results and Forecast Method

Introduction

This California Energy Commission staff report presents forecasts of electricity and natural gas consumption and peak electricity demand for California and for each major utility planning area within the state for 2018—2028. The *California Energy Demand 2018-2028 Preliminary Forecast* (*CED 2017 Preliminary*) supports the analysis and recommendations of the *2016 Integrated Energy Policy Report Update*, including electricity system assessments and analysis of progress toward increased energy efficiency, with goals recently codified in Senate Bill 350 (De León, Chapter 547, Statutes of 2015), and distributed generation.

The Integrated Energy Policy Report (IEPR) Lead Commissioner will conduct a workshop on August 3, 2017, to receive public comments on this forecast. Following the workshop, subject to the direction of the Lead Commissioner, staff will prepare a revised forecast for possible adoption by the Energy Commission. The revised forecast will include an assessment of additional achievable energy efficiency impacts not included in *CED 2017 Preliminary*.

The revised/final forecasts will be used in several applications, including the California Public Utilities Commission (CPUC) resource planning.[2] The CPUC has identified the IEPR process as "the appropriate venue for considering issues of load forecasting, resource assessment, and scenario analyses, to determine the appropriate level and ranges of resource needs for load serving entities in California."[3] The final forecasts will also be an input to the California Independent System Operator (California ISO) Transmission Planning Process as well as controlled grid studies and in electricity supply-demand (resource adequacy) assessments.

CED 2017 Preliminary includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid-energy demand* case. The *high energy demand* case incorporates relatively high economic/demographic growth and climate change impacts, and relatively low electricity rates and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher self-generation impacts. The *mid* case uses input assumptions at levels between the *high*

---

2 Energy Commission and CPUC staffs are working together to properly align the IEPR process with both the Integrated Resource and Distributed Resource Planning processes.

3 Peevey, Michael. September 9, 2004, Assigned Commissioner's Ruling on Interaction Between the *CPUC Long-Term Planning Process and the California Energy Commission Integrated Energy Policy Report Process.* Rulemaking 04-04-003.

and *low* cases. These forecasts are referred to as *baseline* cases, meaning they do not include additional achievable energy efficiency savings.

Details on input assumptions for these cases are provided later in this chapter. The forecast comparisons presented in this report for electricity show the three *CED 2017 Preliminary* cases versus the mid case from the last adopted forecast, *California Energy Demand Updated Forecast, 2017–2027 (CEDU 2016)*, except where otherwise noted. For natural gas, the three *CED 2017 Preliminary* cases are compared to the mid case from the *California Energy Demand 2016-2016 Revised Forecast* (*CED 2015*), since *CEDU 2016* did not include a natural gas assessment.

Summary of Changes to Forecast

CED 2017 Preliminary is based on historical electricity consumption and sales data through 2015 and electricity peak demand and natural gas consumption data through 2016. These historical data are sometimes revised, so that historical numbers provided in some of the tables in this report may differ between the current and past forecasts. The revised version of this forecast will incorporate historical electricity consumption and sales data from 2016 and peak data from 2017.

CED 2017 Preliminary uses the modified geographic scheme for planning areas and climate zones introduced for *CED 2015*,[4] which is more closely based on California's balancing authority areas.[5] The modified scheme has been more fully integrated into the sector models for this forecast through the inputs, rather than relying on mapping of outputs as in previous forecasts. The results of the Energy Commission's ongoing Title 20 data regulations rulemaking will determine the additional consumption and metered data available from the utilities to support further geographic disaggregation of future forecasts. Once the data availability becomes clear, Energy Commission staff will work with the utilities to determine an optimal level of disaggregation to better serve transmission and distribution level analyses.

Utility efficiency program impacts have been updated to reflect activity in 2016 and 2017. Expected program impacts beyond 2017 will be incorporated in the revised version of this forecast through additional achievable energy efficiency (AAEE) savings. The 2016 updates to Title 24 building standards are included in *CED 2017 Preliminary*, with future likely standards updates also handled through AAEE estimates. For the investor-owned utilities (IOUs), estimated AAEE savings will be derived from the CPUC's

---

4 See Kavalec, Chris, Nick Fugate, Cary Garcia, and Asish Gautam. 2016. *California Energy Demand 2016-2026, Revised Electricity Forecast.* California Energy Commission, pp. 20-26. Publication Number: CEC-200-2016-001-V1. Available at [http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf.](http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf)

5 *A balancing authority* is an entity responsible for integrating resource plans and maintaining the proper balance for load, transmission, and generation within an area defined by metered boundaries. California includes eight balancing authorities, of which the California ISO is by far the largest.

2018 Potential and Goals Study,[6] while estimates for publicly owned utilities will be developed through individual utility adopted goals. "Committed" efficiency savings implemented in 2015-2017 (included in this baseline forecast) plus estimated AAEE savings out to 2030 will constitute the contributions from utility programs, as well as building and appliance standards toward meeting the SB 350 goals.[7] The Efficiency Division of the Energy Commission is investigating additional efficiency savings potential outside utility programs and standards available to meet the goals. Depending on progress made in this analysis, some or all of these estimated additional savings may be incorporated in the revised version of this forecast.

The predictive model for self-generation has been modified so that adoption of residential photovoltaic (PV) systems is based on monthly bill savings rather than system payback as in previous forecasts. In addition, the model now incorporates the impact of residential time-of-use (TOU) rates on PV system adoption. **Appendix A** provides full details on these changes.

CED 2017 Preliminary incorporates a new transportation electricity forecast, which includes light-duty vehicles, medium- and heavy-duty vehicles, public transit, and high-speed rail. Light-duty electric vehicle (EV) purchases, which include battery electric and plug-in hybrid, are projected to be more than sufficient to meet the California Air Resources Board's (CARB's) zero-emission vehicle (ZEV) mandates as modeled in the most recent CARB Compliance Case.[8]

Energy Commission staff is developing an hourly load forecasting model for the IOU planning areas, expected to be complete in time for the revised version of this forecast. This model will incorporate hourly PV generation and hourly load impacts of electric vehicles, AAEE, and residential TOU pricing. Staff formulated a preliminary version of this model for *CEDU 2016* to examine potential impacts of a shift in the hour of peak load required from the utilities as a result of these demand modifiers. As in the annual forecast, progress to develop this model for additional utilities and load pockets will depend on the outcome of the current Title 20 rulemaking.

Statewide Results

The *CED 2017 Preliminary* baseline electricity forecast for selected years is compared with the *CEDU 2016* mid demand case[9] in **Table 1**. For both *CED 2017 Preliminary* and

---

6 Draft report available at ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/DAWG/2018andBeyondPotentialandGoals%20StudyDRAFT.pdf.

7 The SB 350 goals for California are formulated as a doubling of AAEE savings estimated for the *California Energy Demand Updated Forecast, 2015-2025 (CEDU 2014)* plus the 2013 publicly owned utility goals, both extrapolated to 2030.

8 The CARB compliance case models a "most likely" future vehicle mix consistent with ZEV requirements. For a summary of the compliance case, see https://www.arb.ca.gov/msprog/acc/mtr/acc_mtr_summaryreport.pdf.

9 All numerical forecast results presented in this report and associated spreadsheets represent expected values derived from model output that have associated uncertainty. The results should therefore be considered in this context rather than precise to the last digit.

CEDU 2016, 2015 is the last historical year consumption was available; the peak forecast for both incorporates 2016 actual peaks. Forecast consumption in the *CED 2017 Preliminary* mid demand case starts below the *CEDU 2016* mid case as additional utility efficiency program impacts are included for the 2016 and 2017 program years. Consumption in the new mid case remains below *CEDU 2016* as 2016 updates to the Title 24 building standards (implemented in 2017) accumulate savings, and, toward the end of the forecast period, forecast EV consumption dips below that in the previous forecast. *CED 2017 Preliminary* statewide noncoincident[10] weather-normalized[11] peak demand is significantly lower than *CEDU 2016* by 2020, reflecting a higher forecast for PV. PV impacts drive average annual growth in peak demand negative from 2016–2020 in the mid demand case, while annual growth is negative throughout the forecast period in the low demand case.

Table 1: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	227,606	227,593	227,593	227,593
2000	261,036	260,940	260,940	260,940
2015	281,334	281,664	281,666	280,922
2020	294,474	296,369	291,991	288,938
2025	312,223	320,008	310,989	305,383
2027	319,256	327,845	316,850	310,297
2028	--	331,320	319,484	312,500
	Average Annual Growth Rates			
1990-2000	1.38%	1.38%	1.38%	1.38%
2000-2015	0.50%	0.51%	0.51%	0.49%
2015-2020	0.92%	1.02%	0.72%	0.56%
2015-2027	1.06%	1.27%	0.99%	0.83%
2015-2028	--	1.26%	0.97%	0.82%
Non-coincident Peak (MW)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand

10 The state's *coincident peak* is the actual peak, while the *noncoincident* peak is the sum of actual peaks for the planning areas, which may occur at different times.

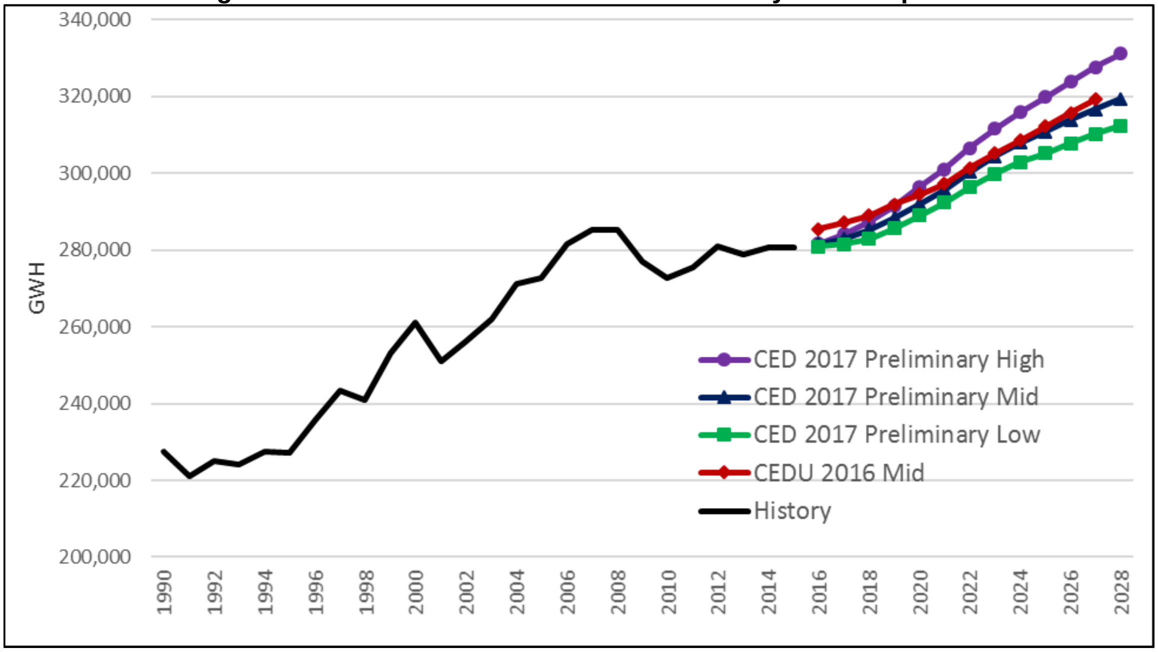
11 Peak demand is weather-normalized in 2014 to provide the proper benchmark for comparison to future peak demand, which assumes either average (normalized) weather or hotter conditions measured relative to 2012 due to climate change.

Consumption (GWh)				
1990	47,123	47,115	47,115	47,115
2000	53,529	53,521	53,521	53,521
2016*	60,543	60,528	60,527	60,527
2020	61,444	60,964	60,074	59,081
2025	63,075	63,987	61,570	59,203
2027	63,501	64,894	61,855	59,052
2028	--	65,273	61,962	58,964
	Average Annual Growth Rates			
1990-2000	1.28%	1.28%	1.28%	1.28%
2000-2016	0.77%	0.77%	0.77%	0.77%
2016-2020	0.37%	0.18%	-0.19%	-0.60%
2016-2027	0.43%	0.64%	0.20%	-0.22%
2016-2028	--	0.63%	0.20%	-0.22%
Actual historical values are shaded.				
*Weather normalized: the forecasts use a weather-normalized peak value derived from the actual 2016 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2017.

Projected electricity consumption for the three *CED 2017 Preliminary* baseline cases and the *CEDU 2016* mid demand forecast is shown in **Figure 1**. In 2027, consumption in the new mid case is projected to be slightly less than 1 percent lower than the *CEDU 2016* mid case, around 2,600 GWh. Annual growth from 2015–2027 for the *CED 2017 Preliminary* forecast averages 1.27 percent, 0.99 percent, and 0.83 percent in the high, mid, and low cases, respectively, compared to 1.06 percent in the *CEDU 2016* mid case.

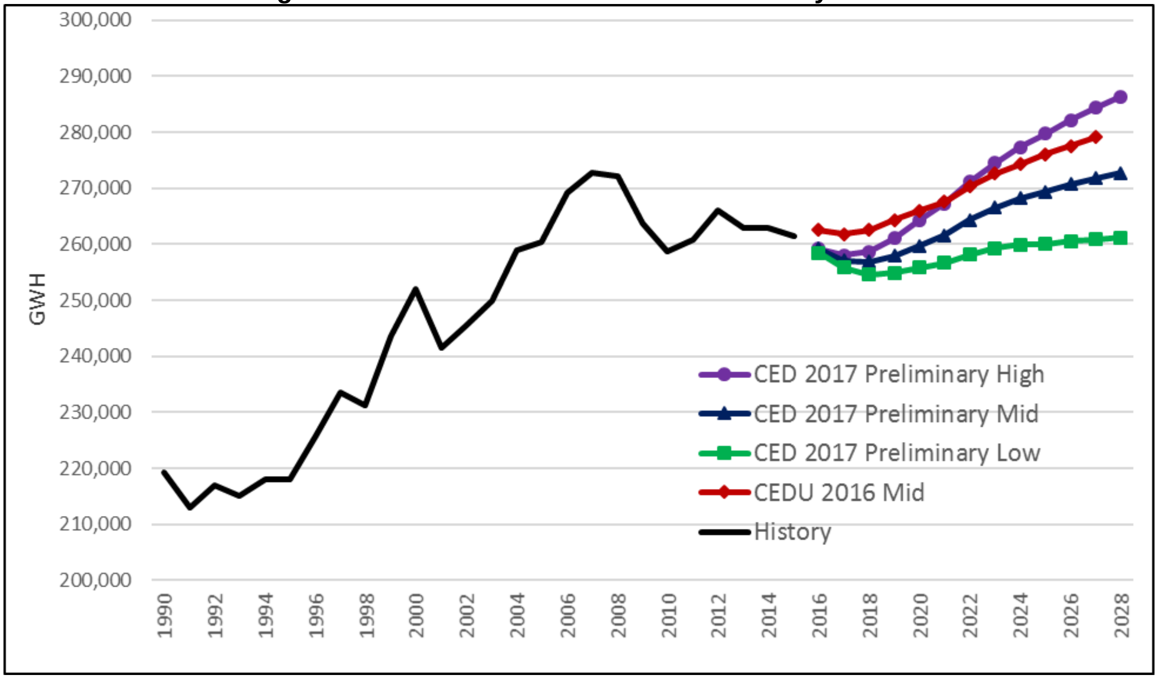
Figure 2: Statewide Baseline Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2017.

The increase in projected consumption met with self-generation in *CED 2017 Preliminary* as a result of more residential PV adoption reduces statewide electricity retail sales by a greater amount compared to *CEDU 2016* than consumption. Projected statewide sales for the three *CED 2017 Preliminary* cases and the *CEDU 2016* mid demand case are shown in **Figure 2.** All three new forecast cases are lower than the *CEDU 2016* mid case at the beginning of the forecast period with the addition of new efficiency program impacts and more PV adoptions, with the new high case pushing above *CEDU 2016* by 2022. By 2027, sales in the *CED 2017 Preliminary* mid scenario are projected to be around 7,300 GWh (2.6 percent) lower than in the *CEDU 2016* mid case. Annual growth from 2015—2027 for the *CED 2017 Preliminary* scenarios averages 0.70 percent, 0.32 percent, and -0.02 percent in the high, mid, and low cases, respectively, compared to 0.52 percent in the *CEDU 2016* mid case.

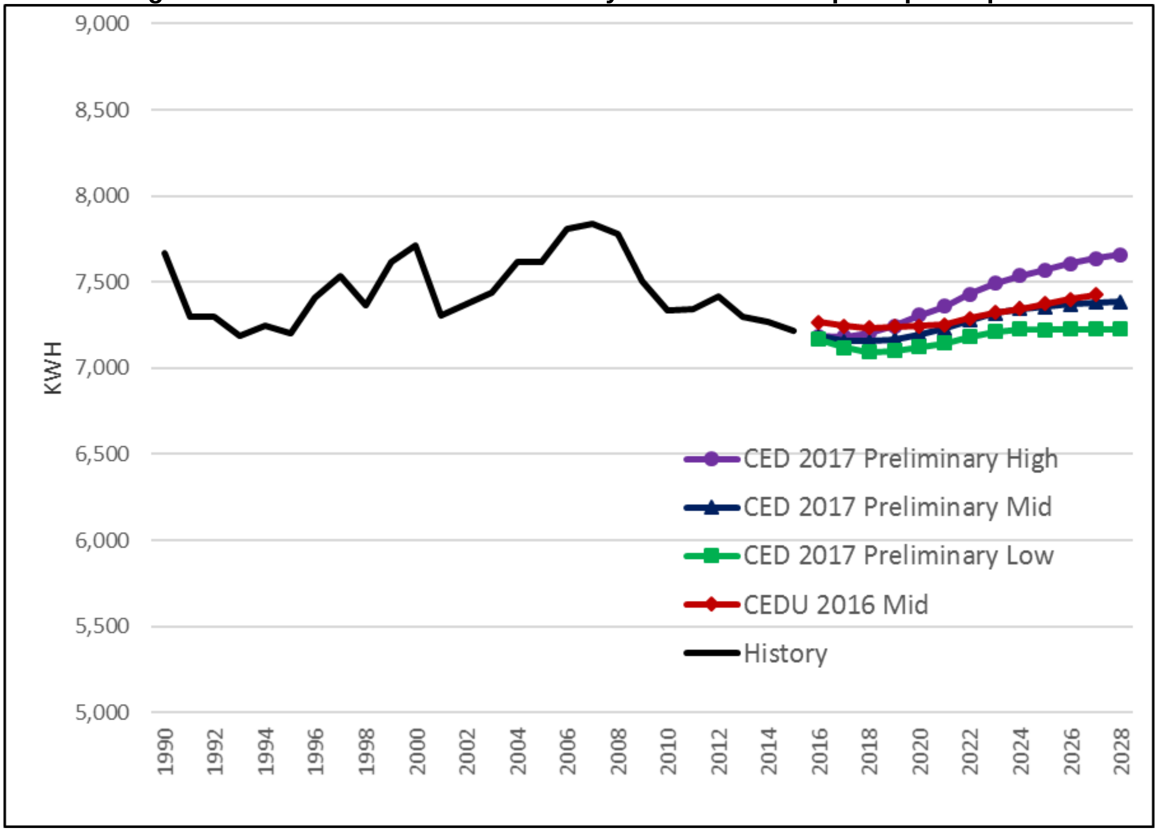
Figure 2: Statewide Baseline Retail Electricity Sales



Source: California Energy Commission, Demand Analysis Office, 2017.

As shown in **Figure 3**, *CED 2017 Preliminary* baseline per capita electricity consumption is projected to be relatively flat through 2021 in the low and mid cases (as in *CEDU 2016* mid) because consumption is projected to grow at about the same rate as population. Thereafter, per capita consumption rises slightly due to increasing EV use. Higher economic/demographic growth in the high demand case combined with EVs increases per capita consumption from 2018 on. Less total electricity consumption in the new mid case reduces per capita consumption relative to the *CEDU 2016* mid case.

Figure 3: Statewide Baseline Electricity Annual Consumption per Capita



Source: California Energy Commission, Demand Analysis Office, 2015.

Projected baseline annual electricity consumption in each *CED 2017 Preliminary* case for the three major economic sectors—residential, commercial, and industrial (manufacturing, construction, and resource extraction)—is compared with the *CEDU 2016* mid demand case in **Table 2**. As in past recent forecasts, residential consumption is projected to grow fastest among the sectors, a result of EVs and steady growth in the miscellaneous sector, which includes "plug-in" appliances such as cell phones and other electronics. Commercial consumption growth is also boosted by EVs but to a lesser degree than in the residential sector: by 2028, residential EV consumption is more than twice as high as commercial. Forecast industrial consumption growth remains flat or declining, a product of recent historical trends in consumption combined with industrial output projections.

Residential consumption in the new mid case grows at a faster rate from 2015–2027 compared to *CEDU 2016* because of the manner in which lighting savings are handled in the new forecast. Past forecasts have assumed reductions in home lighting use consistent with Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007), which calls for 50 percent reductions in residential lighting by 2018 compared to 2007. By assuming that the AB 1109 requirements were met by 2018 and beyond, past forecasts did not measure lighting savings from programs and standards directly. However, given the improvements in evaluation, measurement, and verification (EM&V) studies in recent years, staff decided that incorporating programs and standards targeting lighting would provide a more accurate approach than simply assuming the requirements are met. Because the baseline forecast includes only committed efficiency, lighting savings from programs beyond 2017 that contribute to the AB 1109 goals are not included; so average lighting use begins to increase in 2018 and later years, driving up growth in residential consumption. Additional lighting savings from future programs and standards will be accounted for through AAEE estimates in the revised version of this forecast.

Projected commercial consumption grows at a slower rate in *CED 2017 Preliminary* mid compared to *CEDU 2016* primarily because of the impacts of the 2016 updates to the Title 24 building standards and a decline in projected EV consumption (around 200 GWh less by 2027). Industrial consumption grows at a slightly slower pace in the new mid case compared to *CEDU 2016* despite higher projected growth in manufacturing output as a result of additional efficiency program impacts.

Table 2: Baseline Electricity Consumption by Sector

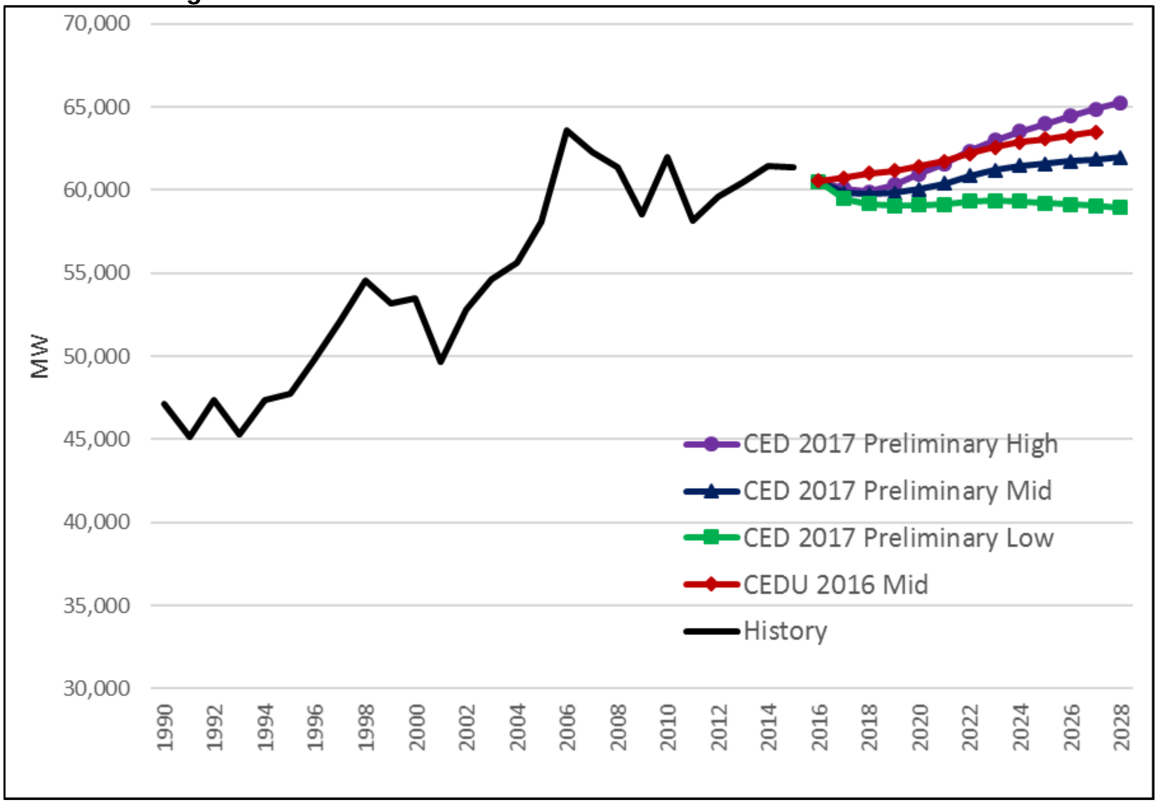
Residential Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
2015	89,192	88,076	88,076	88,076
2020	92,985	96,040	93,920	92,821
2025	103,383	109,632	104,612	102,542
2027	107,993	115,094	108,673	106,203
2028		117,745	110,610	107,930
Average Annual Growth, Residential Sector				
2015-2020	0.84%	1.75%	1.29%	1.06%
2015-2027	1.61%	2.25%	1.77%	1.57%
2015-2028	--	2.26%	1.77%	1.58%
Commercial Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
2015	107,148	107,360	107,360	107,360
2020	112,718	112,004	111,075	110,222

2025	118,473	119,150	117,433	115,663
2027	120,272	120,502	118,540	116,414
2028		120,858	118,814	116,500
Average Annual Growth, Commercial Sector				
2015-2020	1.02%	0.85%	0.68%	0.53%
2015-2027	0.97%	0.97%	0.83%	0.68%
2015-2028	--	0.92%	0.78%	0.63%
Industrial Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
2015	49,590	49,765	49,765	49,765
2020	49,725	49,182	48,296	47,453
2025	49,902	50,551	49,159	47,882
2027	50,009	51,026	49,467	48,075
2028	--	51,285	49,687	48,240
Average Annual Growth, Industrial Sector				
2015-2020	0.05%	-0.24%	-0.60%	-0.95%
2015-2027	0.07%	0.21%	-0.05%	-0.29%
2015-2028	--	0.23%	-0.01%	-0.24%
Actual historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2017.

Projected *CED 2017 Preliminary* noncoincident peak demand for the three baseline cases and the *CEDU 2016* mid demand peak forecast is shown in **Figure 4** and essentially mirrors electricity sales as shown in **Figure 2**. By 2027, statewide peak demand in the new mid case is projected to be 2.6 percent lower than the *CEDU 2016* mid case. Annual growth rates from 2016-2027 for the *CED 2017 Preliminary* scenarios average 0.64 percent, 0.20 percent, and -0.22 percent in the high, mid, and low cases, respectively, compared to 0.43 percent in the *CEDU 2016* mid case. As with sales, higher projected self-generation reduces the growth rate in the new mid case compared to *CEDU 2016*. The lower projections for EVs have relatively less impact on peak demand than consumption and sales, as staff assumes that most recharging occurs in off-peak hours.[12]

Figure 4: Statewide Baseline Annual Noncoincident Peak Demand

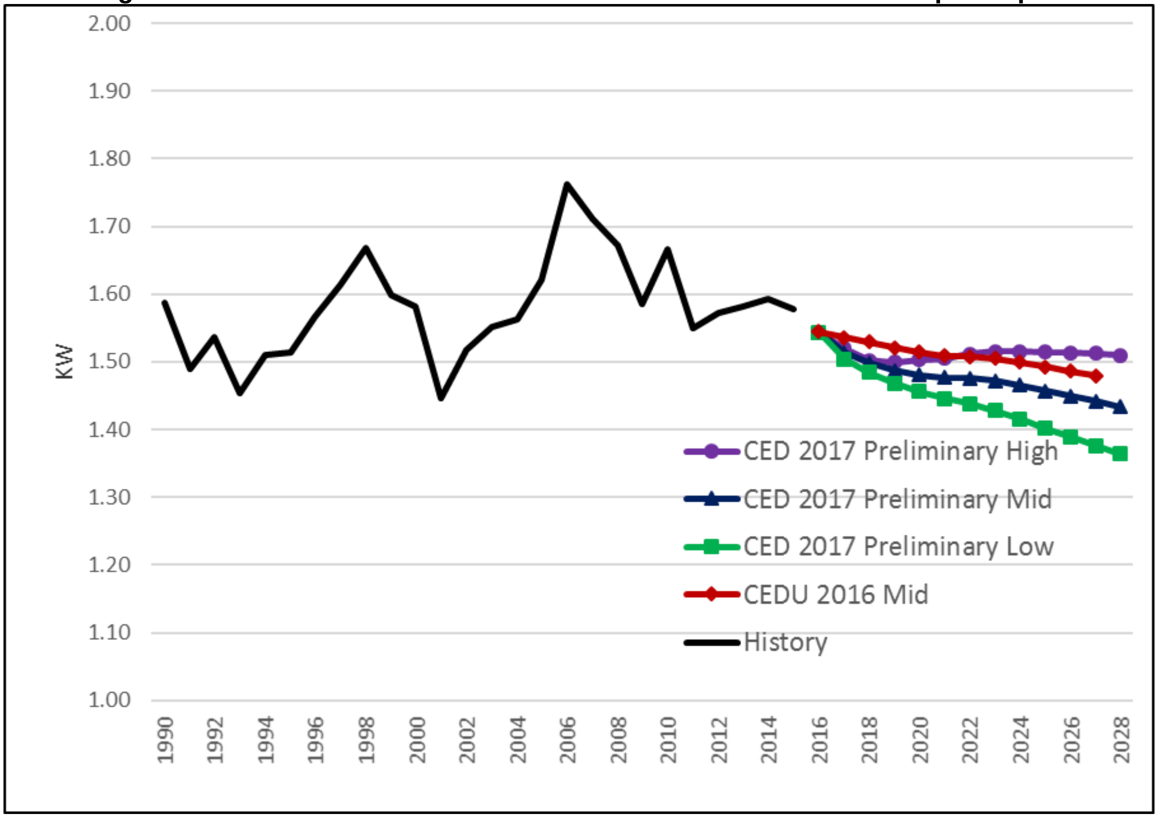


Source: California Energy Commission, Demand Analysis Office, 2017.

Statewide noncoincident peak demand per capita for the three *CED 2017 Preliminary* cases and the *CEDU 2016* mid case is shown in **Figure 5**. Increasing peak demand met by self-generation leads to declining demand per capita in the new mid and low cases (as well as *CEDU 2016* mid) throughout the forecast period. Increased PV adoption in the new forecast reduces mid case peak demand per capita by around 3 percent by 2027 compared to *CEDU 2016*. In the *CED 2017 Preliminary* high demand case, faster economic growth combined with less self-generation compared to the other two cases results in increasing peak demand per capita from 2018–2024.

12 As in past forecasts, staff assumed 75 percent of recharging would take place during off-peak hours (10 p.m. – 6 a.m.), with the rest evenly distributed over the remaining hours. Work in the Demand Analysis Office of the Energy Commission, through a consultant study, will provide an updated peak factor for the revised version of this forecast.

Figure 5: Statewide Baseline Annual Noncoincident Peak Demand per Capita



Source: California Energy Commission, Demand Analysis Office, 2017.

Table 3 shows statewide end-user natural gas consumption demand for the three *CED 2017 Preliminary* cases and the mid case from *CED 2015* (a natural gas end-use forecast was not done for *CEDU 2016*). The natural gas forecast is developed using the same models as the electricity forecast, with similar adjustments for utility efficiency programs and building and appliance standards.[13] The table shows a rather large jump from 2016 to 2017 in the new forecast, a result of the weather adjustment process in the residential and commercial models. The year 2016 was very warm in general, with a relatively small number of heating degree days[14] over the year. With heating accounting for almost 50 percent of natural gas demand in the residential and commercial sectors, consumption in 2016 would have been reduced significantly. In 2017 (and the rest of the forecast period), weather is assumed to be historically "average," so that the number of heating degree days increases relative to 2016, accounting for this jump. In 2017 and

13 The revised version of the natural gas forecast will also incorporate AAEE savings derived from the CPUC's Potential and Goals Study.

14 *Heating degree days* is a parameter that is designed to reflect the demand for energy needed to heat a home or building. Heating degree days are calculated using ambient air temperatures and a base temperature (for example, 65 degrees) below which it is assumed that space heating is needed.

beyond, growth in the new mid case is slightly lower than in *CED 2015*, a result of slower population growth compared to that predicted for *CED 2015*.

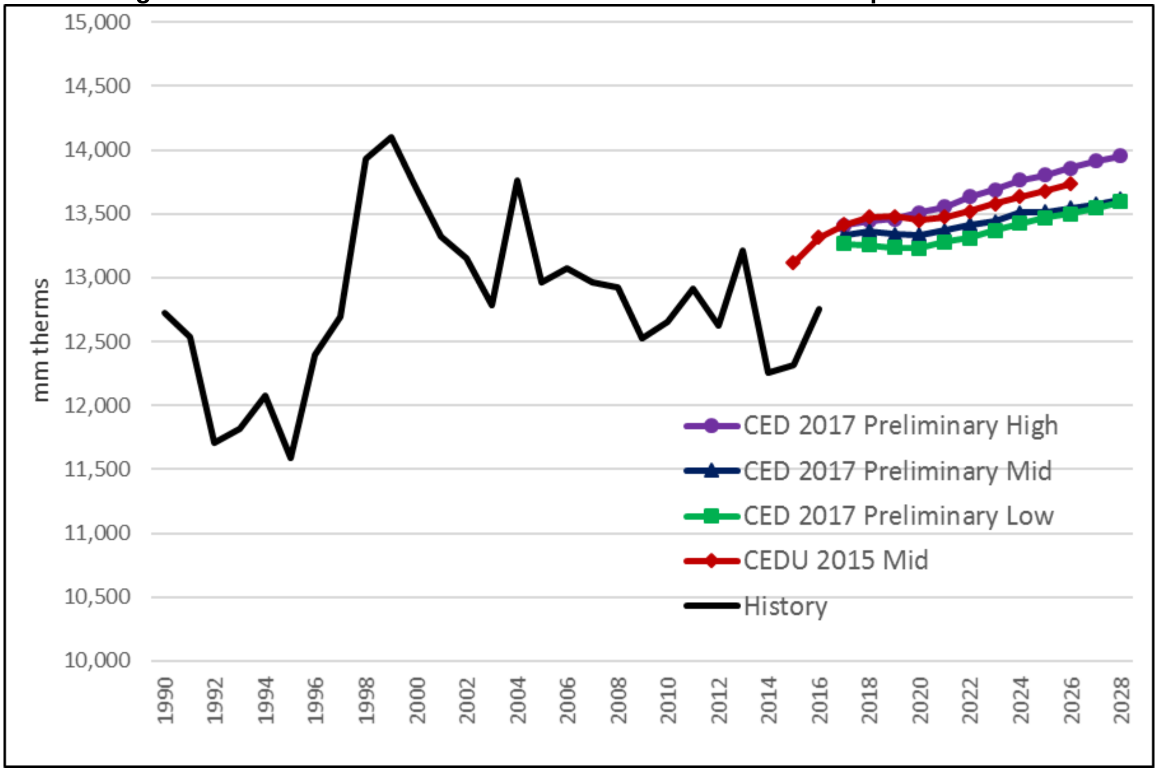
Table 3: Comparison of CED 2017 Preliminary and CED 2015 Mid Case Demand Baseline Forecasts of Statewide End-User Natural Gas Consumption

Natural Gas Consumption (mm therms)				
	CED 2015 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	12,892	12,724	12,724	12,724
2000	13,913	13,713	13,713	13,713
2016	13,318	12,751	12,751	12,751
2017	13,417	13,412	13,329	13,265
2020	13,450	13,508	13,337	13,230
2025	13,681	13,803	13,514	13,468
2026	13,736	13,857	13,547	13,501
2028	--	13,952	13,613	13,595
	Average Annual Growth Rates			
1990-2000	0.77%	0.75%	0.75%	0.75%
2000-2016	-0.29%	-0.48%	-0.48%	-0.48%
2016-2020	0.25%	1.45%	1.13%	0.93%
2016-2026	0.31%	0.84%	0.61%	0.57%
2016-2028	--	0.75%	0.55%	0.54%
Actual historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2017.

Statewide natural gas consumption demand for the three *CED 2017 Preliminary* cases and the *CED 2015* mid case is also shown in **Figure 6.** The historical series clearly shows the variability in consumption from year to year, with changes in weather a key contributor to this variability. For the period 2016-2026, annual growth in consumption averages 0.84 percent, 0.61 percent, and 0.57 percent in the high, mid, and low cases, respectively, compared to 0.32 percent in the *CED 2015* mid case. By the end of the forecast period, low case consumption is almost identical to the new mid case, a result of climate change impacts that affect (reduce) the mid case totals but not the low.

Figure 6: Statewide Baseline End-User Natural Gas Consumption Demand



Source: California Energy Commission, Demand Analysis Office, 2017.

Method

Although the method to estimate energy efficiency impacts and self-generation have undergone refinement, *CED 2017 Preliminary* uses the same technical methods as previous long-term staff demand forecasts: detailed sector models supplemented with single equation econometric models, now applied to a revised geographic scheme. A full description of the sector models is available in a staff report.[15]

Geography

Staff energy demand forecasts are developed for eight electricity planning areas and four natural gas planning areas, with the electricity planning areas revised as of *CED 2015*. **Table 4** shows the load-serving entities included in each planning area. The Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Valley Electric Association (VEA) electricity planning areas correspond to the four transmission access charge (TAC) areas[16] within the California ISO balancing authority area. The Northern California-non California ISO (NCNC) planning area is composed of two balancing authority areas: Turlock Irrigation District and the Balancing

15 http://www.energy.ca.gov/2005publications/CEC-400-2005-036/CEC-400-2005-036.PDF.

16 A *transmission access charge* (TAC) area is a portion of the California ISO-controlled grid where transmission revenue requirements are recovered through an access charge.

Authority of Northern California (BANC), which includes the Sacramento Municipal Utility District (SMUD). The Los Angeles Department of Water and Power (LADWP) and Burbank-Glendale (BUGL) planning areas together comprise the LADWP balancing authority area, and the Imperial Irrigation District (IID) is both a planning area and a balancing authority area. The smallest planning areas, VEA for electricity and other for natural gas, are not incorporated within the demand forecast models but are postprocessed, with energy demand growth projected based on an average of the other planning areas.

Some of the electricity planning areas is further divided into forecast zones. PG&E contains six zones, SCE five, NCNC three, and LADWP two. Staff does not provide individual forecast for these zones for *CED 2017 Preliminary*, with the exception of SMUD, a forecast zone within the NCNC planning area. The revised version of this forecast will include full forecast zone projections.

Table 4: Load-Serving Entities Within Forecasting Planning Areas

Planning Area	Utilities Included	
Electric Planning Areas		
Pacific Gas and Electric (PG&E)	PG&E	Palo Alto
	Alameda	Plumas – Sierra
	Biggs	Port of Oakland
	Calaveras	Port of Stockton
	Department of Water Resources (North)	Power and Water Resources
	Gridley	Pooling Authority
	Healdsburg	San Francisco
	Hercules	Silicon Valley
	Island Energy	Tuolumne
	Lassen	Ukiah
	Lodi	Central Valley Project (California ISO operations)
	Lompoc	
Southern California Edison (SCE)	Anaheim	Moreno Valley
	Anza	Pasadena
	Azusa	Rancho Cucamonga
	Banning	Riverside

Planning Area	Utilities Included
	Bear Valley Colton Corona Department of Water Resources (South) Metropolitan Water District SCE U.S. Bureau of Reclamation-Parker Davis Vernon Victorville
San Diego Gas & Electric (SDG&E)	SDG&E
Northern California, Non-California ISO (NCNC)	Merced Modesto Redding Roseville Shasta SMUD Turlock Irrigation District Central Valley Project (BANC operations)
Los Angeles Department of Water and Power (LADWP)	LADWP
Burbank and Glendale (BUGL)	Burbank, Glendale
Imperial Irrigation District (IID)	IID
Valley Electric Association (VEA)	VEA
Natural Gas Planning Areas	
PG&E	PG&E, Palo Alto
Southern California Gas Company (SoCal Gas)	SoCal Gas, Long Beach, Northwest Pipeline, Mojave Pipeline
SDG&E	SDG&E
Other	Southwest Gas Corporation, Avista Energy

Source: California Energy Commission, Demand Analysis Office, 2017.

Economic and Demographic Inputs

Projections for statewide economic and demographic growth are summarized here. More detail, at the statewide level as well as for each planning area, is provided in the demand forms accompanying this report.[17] As in previous forecasts, staff relied on Moody's Analytics (Moody's) and IHS Global Insight (Global Insight) to develop the economic growth scenarios to drive the three *CED 2015 Preliminary* demand cases. Demographic inputs relied on these two sources as well as the latest forecasts from the California Department of Finance (DOF).

For the mid-energy demand case, staff chose Moody's *Baseline* economic scenario, as in past forecasts. At staff's request, Moody's developed a more aggressive *Custom High Growth* scenario for California for the high demand case. In the past, the higher growth scenarios provided by Moody's tended to be very close to the associated *Baseline* scenario, so staff used Global Insight's *Optimistic* economic scenario to provide a demand case notably higher than the mid case. However, the Global Insight scenario was sometimes inconsistent with the Moody's scenarios, in the sense that lower growth was projected for some sectors versus the Moody's *Baseline* scenario even when overall growth was forecast higher. This inconsistency sometimes led to demand forecasts with slower growth in the high energy demand case for some sectors compared to the mid and low cases. The new *Custom High Growth* scenario allows consistency among the economic scenarios at the sector level while yielding sufficiently significant differences between the high and mid-energy demand cases. Moody's *Below-Trend Long-Term Growth* economic scenario was used for the low demand case; other slower growth economic scenarios yielded less growth in the short term but almost identical results relative to the *Baseline* scenario 10 years out.

For population, staff used only one scenario, the DOF forecast, since Moody's, Global Insight, and DOF projected very similar growth.[18] The DOF projections for several households were used in the mid and low demand cases, with Moody's used for the high case. The key assumptions used by Moody's to develop the three economic scenarios applied in this forecast are provided in **Table 5**.

Table 5: Key Assumptions Embodied in *CED 2017 Preliminary* Economic Scenarios

High Demand Case (Moody's Custom High Growth Scenario), January 2017	***Mid Demand Case (Moody's Baseline Scenario), January 2017***	***Low Demand Case (Moody's Below-Trend Long-Term Growth Scenario), January 2017***
National unemployment rate will be more than 4 percent through 2018.	National unemployment rate stays below 5 percent through 2018.	National unemployment rate will be slightly more than 5 percent through 2018.
The Federal Reserve responds to the hotter labor	The Federal Reserve is expected to steadily	The high value of the dollar limits exports, as does the

17 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-03.

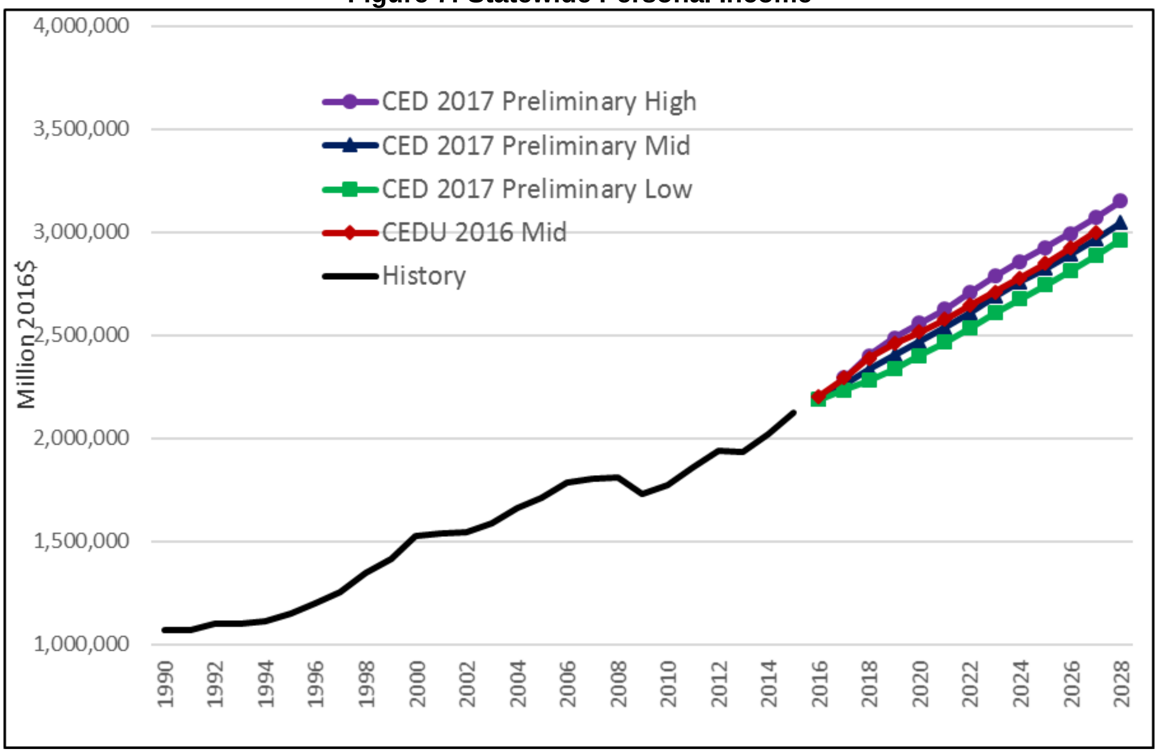
18 Moody's and Global Insight provide only one scenario for population and number of households.

High Demand Case (Moody's Custom High Growth Scenario), January 2017	***Mid Demand Case (Moody's Baseline Scenario), January 2017***	***Low Demand Case (Moody's Below-Trend Long-Term Growth Scenario), January 2017***
market, higher wages, and the potential for higher inflation by raising interest rates.	normalize interest rates over the next three years. The dollar should appreciate against the Japanese yen and British pound.	slower than expected Eurozone recovery.
National light-duty vehicle sales increase to 17.7 million in 2018	National light-duty vehicle sales hit 17.3 million in 2018.	National light-duty vehicle sales decline to 16.8 million in 2018.
National housing starts reach nearly 2 million units by 2018.	National housing starts are expected to be 1.7 million units by 2018.	National housing starts reach 1.42 million units by 2018.
Stronger U.S. and global GDP growth increases demand for oil, helping the market rebalance more quickly than in the mid- or low-demand scenarios. Excess supply is reduced, and demand begins to outstrip supply, putting upward pressure on oil prices.	Oil prices will remain volatile but rise slowly.	Structural oversupply conditions in oil markets keep oil prices low.
Though the economy grows above its potential, the government's fiscal situation continues to weaken but less than under the other two scenarios.	The Trump administration pushes forward its fiscal policy agenda. This agenda is uncertain, however, Moody's assumes there will be tax cuts costing close to $1 trillion over the next decade.	Economic policies of the new presidential administration increase uncertainty among businesses and households alike, which slows growth and worsens the government's fiscal situation.

Source: Moody's Analytics, 2017.

Historical and projected personal income at the statewide level for the three *CED 2017 Preliminary* cases and the *CEDU 2016* mid demand case is shown in **Figure 7.**[19] The new mid case is slightly lower than the *CEDU 2016* mid case at the end of the forecast period (around 2.3 percent in 2027), although the difference is greater from 2018–2022. Annual growth rates from 2015–2027 average 3.12 percent, 2.82 percent, and 2.59 percent in the *CED 2017 Preliminary* high, mid, and low cases, respectively, compared to 2.92 percent in the *CEDU 2016* mid case.

Figure 7: Statewide Personal Income



Source: Moody's Analytics, 2016-2017.

Historical and projected statewide commercial employment[20] for the three *CED 2017 Preliminary* cases and the *CEDU 2016* mid demand case is shown in **Figure 8**. The *CED 2017 Preliminary* mid case is almost identical to *CEDU 2016* by the end of the forecast period, with the difference between the new and old mid cases around 0.1 percent in 2027. Annual growth rates from 2015–2027 average 1.23 percent, 1.13 percent, and 1.04 percent in the *CED 2017 Preliminary* high, mid, and low cases, respectively, compared to 1.14 percent in the *CEDU 2016* mid case.

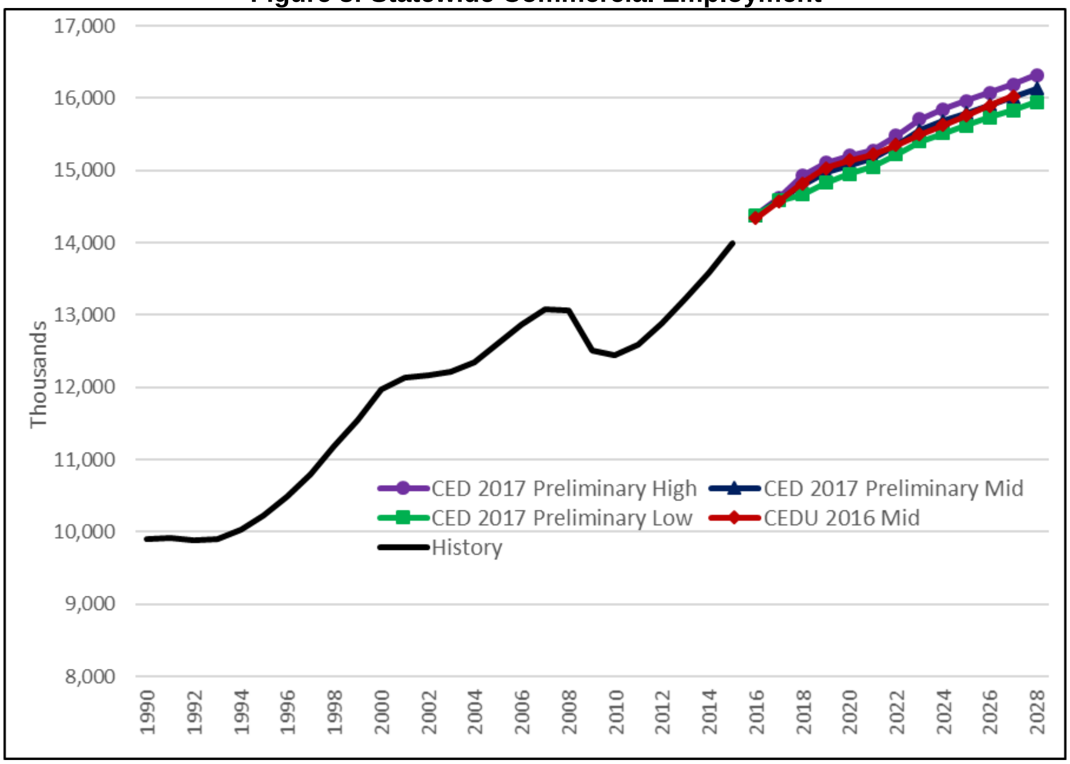
---

19 To account for periodic revisions to the historical data by Moody's, the *CEDU 2016* mid economic case in this section is scaled so that levels match those used in *CED 2017 Preliminary* in 2015.

20 Defined as total nonagricultural employment minus manufacturing, resource extraction, and construction employment.

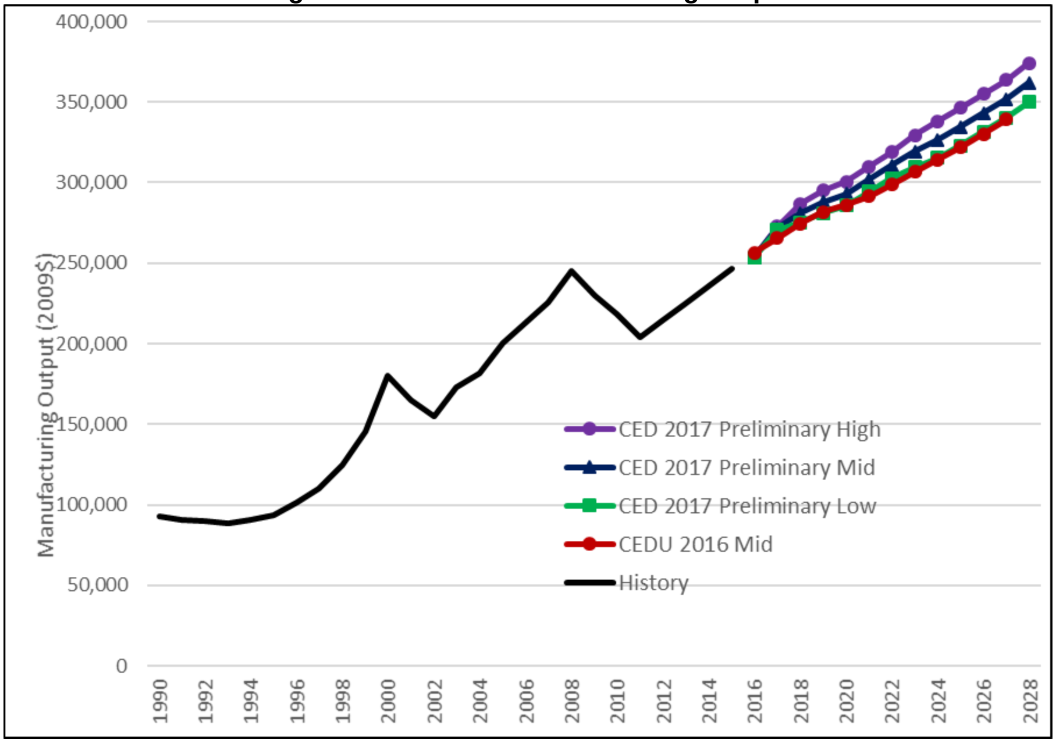
Statewide manufacturing output for the three *CED 2017 Preliminary* cases and the *CEDU 2016* mid demand case is shown in **Figure 9**. The *CED 2017 Preliminary* mid case is slightly above *CEDU 2016*, which is closer to the new low case. Annual growth rates from 2015-2027 average 3.29 percent, 3.00 percent, and 2.72 percent in the *CED 2017 Preliminary* high, mid, and low cases, respectively, compared to 2.69 percent in the *CEDU 2016* mid case.

Figure 8: Statewide Commercial Employment



Source: Moody's Analytics, 2016-2017.

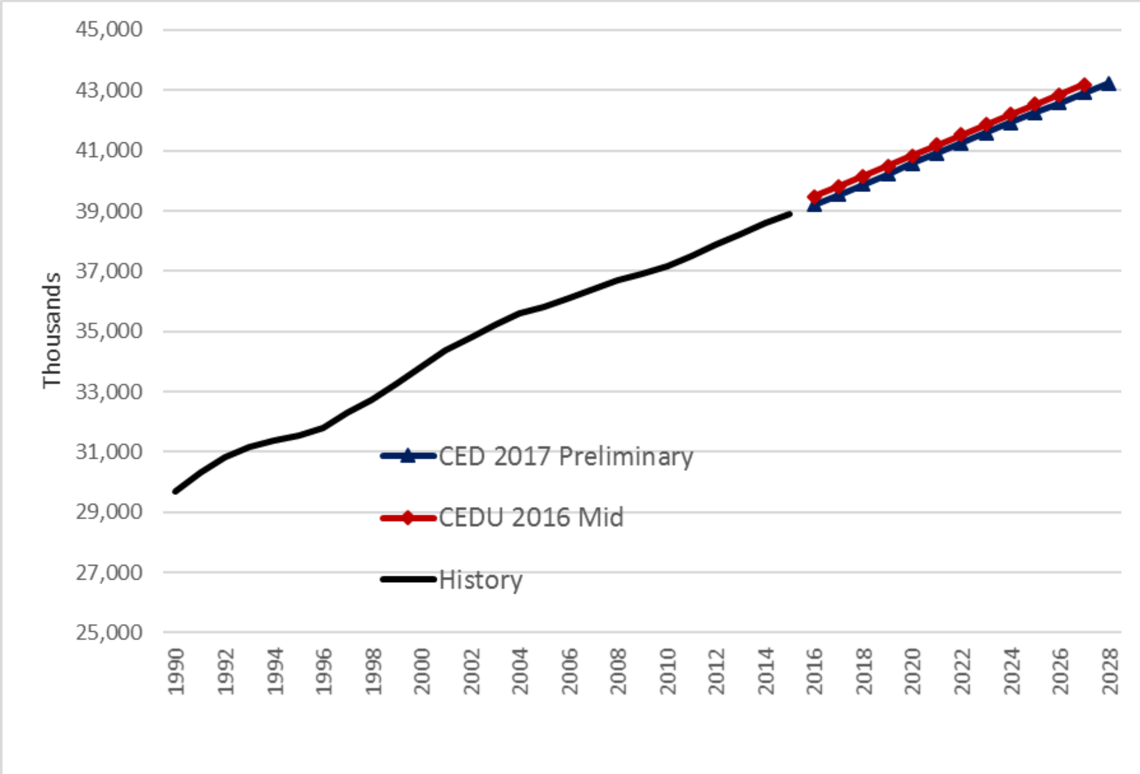
Figure 9: Statewide Manufacturing Output



Source: Moody's Analytics, 2016-2017.

Projections for population are shown in **Figure 10.** The single *CED 2017 Preliminary* scenario projects a slightly lower population compared to the *CEDU 2016* mid case throughout the forecast period. In 2027, the difference amounts to around 0.6 percent. Over the period 2015–2027, population growth averages around 0.82 percent for *CED 2017 Preliminary* compared to 0.87 percent in the *CEDU 2016* mid case.

Figure 10: Statewide Population



Sources: California Department of Finance, 2017, and Moody's Analytics, 2016.

With slightly lower population and personal income in the new mid case counterbalanced by higher manufacturing output, the economic/demographic drivers overall do not significantly change the mid case compared to *CEDU 2016*. Rather, the key demand modifiers, including PV, EVs, and efficiency, have a more important role in forecast differences.

Electricity and Natural Gas Rates

Electricity rate scenario cases used in *CED 2017 Preliminary* were developed using a staff electricity rate model introduced for *CED 2015*, estimated by the Energy Commission's Supply Analysis Office.[21] The model uses a set of simultaneous equations to estimate future revenue requirements, allocate them to rate classes, and calculate annual average class rates. Rate scenarios are developed independently for all the planning areas (minus VEA).

Electricity rate scenarios for the five major planning areas for selected years for the three major sectors by demand case are shown in **Table 6.** A full listing of historical and projected rates by planning area is available in the demand forms accompanying this

21 For details on the method, see Kavalec, Chris, Nick Fugate, Cary Garcia, and Asish Gautam. 2016. *California Energy Demand 2016-2026, Revised Electricity Forecast*. California Energy Commission, pp. 32-34. Publication Number: CEC-200-2016-001-V1. Available at http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf.

report.[22] The effect of increasing rates on the forecast is determined by model price elasticities of demand,[23] which average about 10 percent across the sectors.

Table 6: Electricity Rates by Demand Case, Five Major Planning Areas (2016 cents per kWh)

Planning Area	Year	Residential			Commercial			Industrial		
		High	Mid	Low	High	Mid	Low	High	Mid	Low
PG&E	2015	17.53	17.53	17.53	17.76	17.76	17.76	11.06	11.06	11.06
	2020	19.81	20.51	21.05	20.66	21.31	21.56	14.32	14.92	15.42
	2025	19.45	21.69	24.94	21.87	23.65	24.80	14.90	16.33	17.48
	2028	19.25	21.88	26.26	21.97	24.04	25.67	14.86	16.49	17.94
SCE	2015	16.74	16.74	16.74	14.85	14.85	14.85	11.53	11.53	11.53
	2020	18.85	19.84	20.64	17.01	17.75	18.21	12.06	12.84	13.63
	2025	18.08	20.74	24.25	17.63	18.72	19.40	11.94	13.33	14.54
	2028	18.09	21.24	25.77	17.97	19.22	20.02	12.06	13.65	15.04
SDG&E	2015	21.07	21.07	21.07	21.20	21.20	21.20	13.60	13.60	13.60
	2020	23.39	24.93	25.46	19.13	19.92	20.21	12.04	12.77	13.19
	2025	22.06	25.61	27.17	19.45	20.92	21.53	12.03	13.21	14.14
	2028	21.52	26.15	28.90	20.11	21.90	22.87	12.20	13.66	14.95
NCNC	2015	14.79	14.79	14.79	13.77	13.77	13.77	10.85	10.85	10.85
	2020	14.51	14.91	15.53	13.26	13.56	14.00	10.47	10.78	11.24
	2025	14.99	15.94	17.38	13.17	13.96	15.10	10.40	11.10	12.12
	2028	15.20	16.51	18.49	13.05	14.13	15.71	10.30	11.23	12.62
LADWP	2015	15.59	15.59	15.59	15.11	15.11	15.11	14.35	14.35	14.35
	2020	15.85	16.20	16.92	15.20	15.55	16.26	14.75	15.15	15.98
	2025	15.68	16.72	18.58	15.05	15.76	17.86	14.63	15.56	17.63
	2028	15.56	17.07	19.76	14.93	15.88	19.00	14.52	15.79	18.76

Source: California Energy Commission, Supply Analysis Office, 2017.

22 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-03.

23 A *price elasticity of demand* measures the percentage change in demand induced by a given percentage change in price. An elasticity of 10 percent means, for example, that a doubling of prices would be expected to reduce demand by 10 percent, all else equal.

Natural gas price scenarios were developed by the Energy Commission's Supply Office using the North American Gas-Trade Model (NAMGas). This model incorporates supply and demand components to generate equilibrium gas prices for California and subregions. The natural gas price scenarios were designed to be consistent with the demand cases as well as the electricity rate scenarios, which use natural gas prices as an input. The assumptions behind the natural gas scenarios were presented at an IEPR workshop on April 25, 2017.[24]

Price scenarios for the three major gas planning areas for selected years for the three major sectors by demand case are shown in **Table 7**. A full listing of historical and projected rates by planning area is available in the demand forms accompanying this report.[25] Similar to electricity, price elasticities average about 10 percent across the sectors.

Table 7: Retail Natural Gas Prices by Demand Case for Three Major Planning Areas (2016 $ per Therm)

Planning Area	Year	Residential			Commercial			Industrial		
		High	Mid	Low	High	Mid	Low	High	Mid	Low
PG&E	2015	1.35	1.32	1.30	1.04	1.01	0.99	0.78	0.75	0.73
	2020	1.68	1.59	1.51	1.34	1.25	1.18	0.84	0.75	0.67
	2025	1.78	1.71	1.61	1.43	1.36	1.26	0.91	0.84	0.74
	2028	1.85	1.76	1.68	1.49	1.41	1.32	0.95	0.87	0.78
SoCalGas	2015	0.94	0.92	0.91	0.80	0.78	0.77	0.80	0.78	0.77
	2020	1.20	1.09	1.02	1.06	0.95	0.88	1.06	0.95	0.88
	2025	1.30	1.20	1.10	1.16	1.05	0.95	1.16	1.05	0.95
	2028	1.36	1.23	1.14	1.21	1.08	0.99	1.20	1.08	0.99
SDG&E	2015	1.30	1.27	1.26	0.76	0.73	0.72	0.42	0.39	0.37
	2020	1.63	1.52	1.44	1.00	0.88	0.81	1.00	0.88	0.81
	2025	1.75	1.64	1.54	1.09	0.98	0.89	1.09	0.98	0.88
	2028	1.82	1.69	1.60	1.14	1.02	0.93	1.14	1.01	0.92

Source: California Energy Commission, Supply Analysis Office, 2017.

Self-Generation

As in previous forecasts, *CED 2017 Preliminary* attempts to account for all major self-generation technologies, including PV, different forms of combined heat and power (CHP), wind turbines, electric fuel cells, solar water heating, and behind-the-meter storage, as well as the programs designed to promote the adoption of these technologies, building up from sales of individual systems. **Appendix A** provides a description of the major current incentive programs.

24 Materials available at http://www.energy.ca.gov/2017_energypolicy/documents/#04252017.

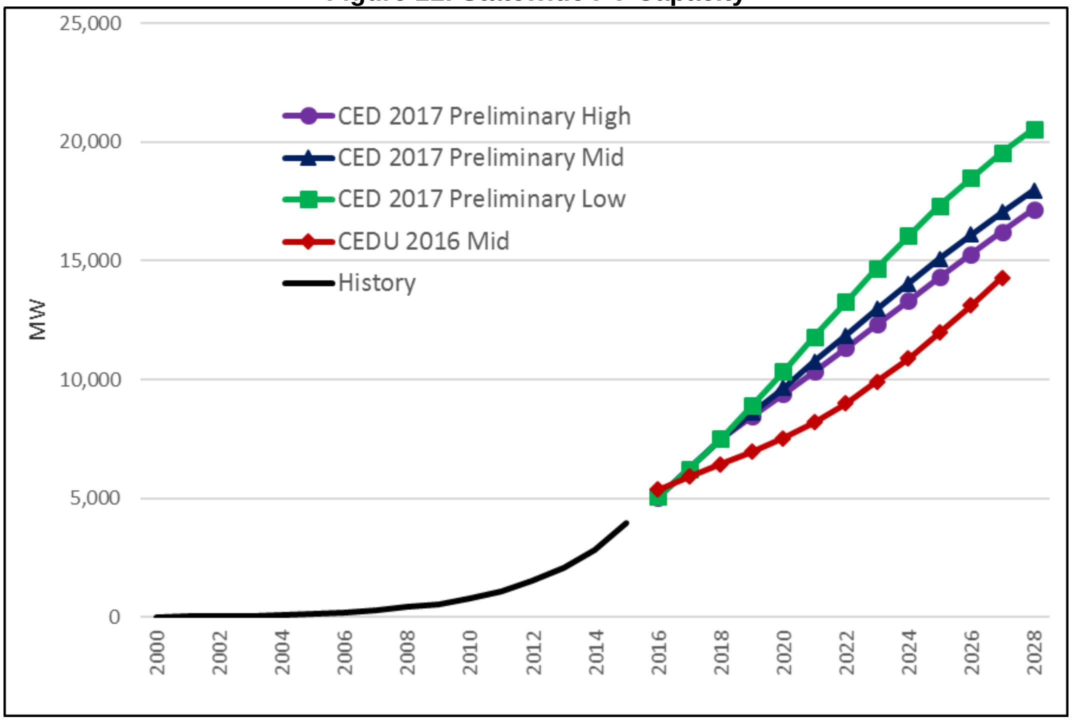
25 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-03.

In recent demand forecasts, residential and commercial PV, residential solar water heating, and commercial CHP adoption have been projected using predictive models, based on estimated payback periods and cost-effectiveness, determined by upfront costs, energy rates, and incentive levels. For *CED 2017 Preliminary*, staff modified the residential PV model so that adoptions are based on monthly bill savings rather than payback, based on the manner in which PV systems are marketed. This change resulted in a significant increase in projected adoption of PV systems, as shown below, while providing a better fit for recent historical adoptions. In addition, staff incorporated residential TOU programs for PV prediction starting in 2019, so that monthly bill savings and therefore adoptions are based on modified residential load patterns. To account for uncertainty around the net energy metering (NEM) policy, similar to *CED 2015*, staff assumed full retail compensation for excess generation in the low demand (high self-generation) case, 10 cents per kWh in the mid demand case, and 10 cents per kWh plus a fixed capacity charge in the high demand (low self-generation) case. **Appendix A** provides more detail on staff's predictive methods and assumptions, as well as a discussion of NEM and other relevant issues.

Historical and projected PV capacity for the three *CED 2017 Preliminary* demand cases and the *CEDU 2016* mid case are shown in **Figure 11**. The change in residential modeling method is responsible for almost all the increase in PV adoption, pushing up capacity by around 3,000 MW in the new mid case compared to *CEDU 2016* by 2027. As shown in **Figure 12**, self-generation overall is projected to reduce peak load provided by utilities by about 9,300 MW in the new mid case by 2027, an increase of around 1,200 MW compared to *CEDU 2016*. Residential PV is responsible for about 1,100 MW of this increase. These estimates do not consider potential peak shift (utility-provided peak load moving to a later hour), which would reduce self-generation peak impact through less PV generation. The demand forms accompanying this report[26] provide annual results for energy and peak impacts for total self-generation and PV for each planning area and statewide.

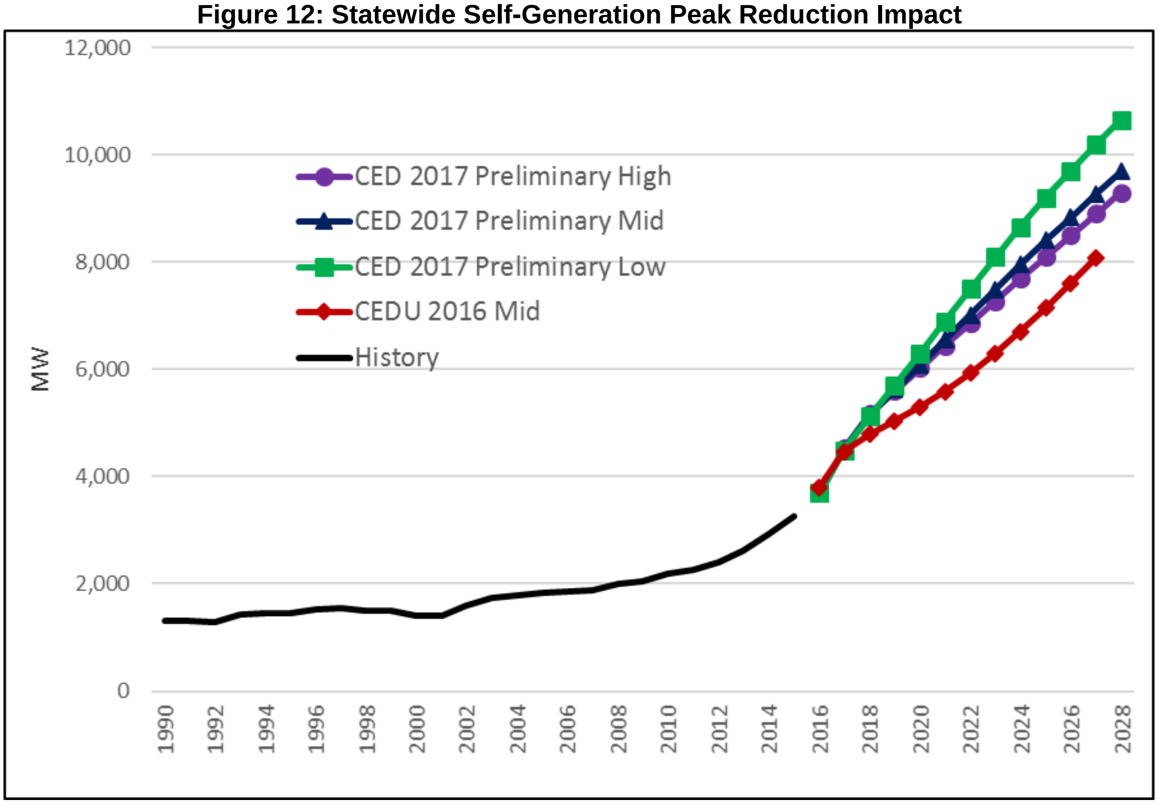
26 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-03.

Figure 11: Statewide PV Capacity



Source: California Energy Commission, Demand Analysis Office, 2017.

Figure 12: Statewide Self-Generation Peak Reduction Impact



Source: California Energy Commission, Demand Analysis Office, 2017.

Conservation/Efficiency Impacts

Energy Commission demand forecasts seek to account for efficiency and conservation *reasonably expected to occur*. Reasonably expected to occur initiatives have been split into two types: committed and additional achievable energy efficiency. The *CED 2017 Preliminary* baseline forecasts continue that distinction, with only committed efficiency included. Committed initiatives include utility programs, codes and standards, and legislation and ordinances having final authorization, firm funding, and a design that can be readily translated into characteristics capable of being evaluated and used to estimate future impacts (for example, a package of IOU incentive programs that has been funded by CPUC order). In addition, committed impacts include price and other market effects not directly related to a specific initiative.

CED 2017 Preliminary includes estimated committed efficiency impacts not included in *CEDU 2016*, from 2016–2017 programs for both IOUs and publicly owned utilities. In addition, staff has revised the estimated savings from 2010-2015 IOU programs based on the most recent CPUC evaluation, measurement, and verification (EM&V) study.[27] The study showed that actual realization of savings was below that anticipated for the 2010-2012 IOU programs, and staff applied adjustment factors to 2010-2015 savings embedded in the forecast to account for this difference.

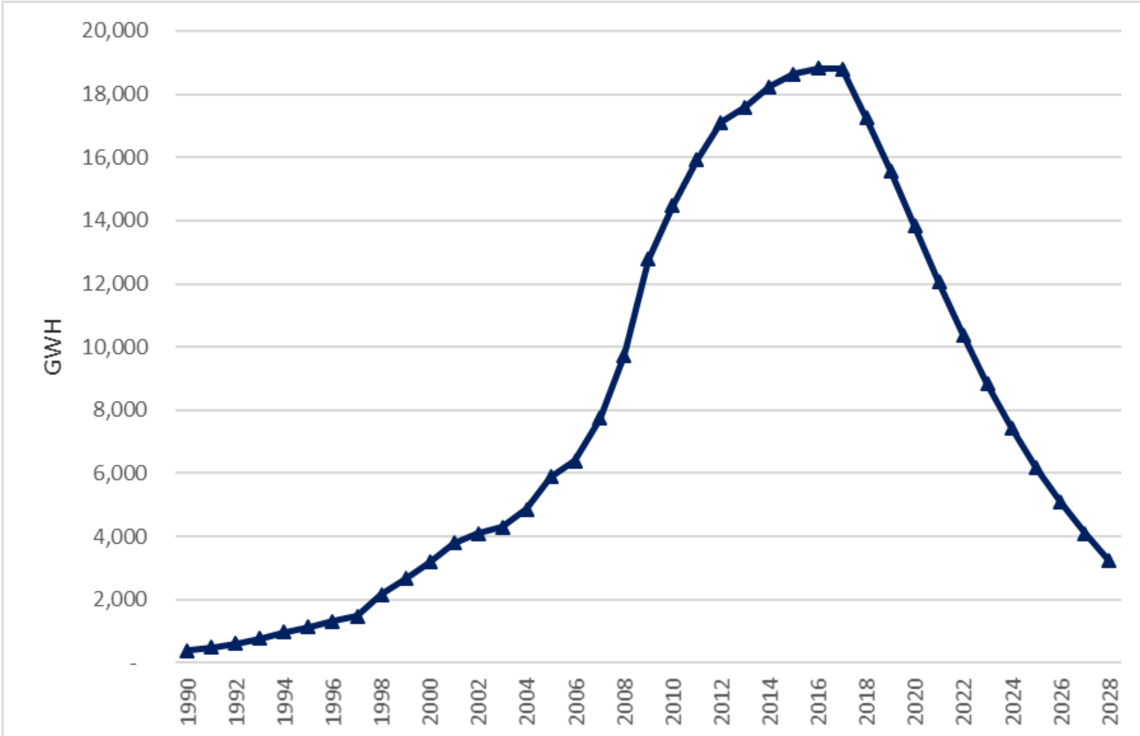
Figure 13 shows estimated historical and projected committed utility program savings for electricity statewide,[28] which reach around 18,800 GWh by 2017. **Figure 14** shows natural gas program savings, which reach about 220 million therms by the same year. Since these are committed programs, no new savings are added after 2017, and therefore the totals drop quickly as program measures from previous years reach the end of the useful life. The decline after 2017 will be counterbalanced by the addition of AAEE program savings for the revised version of this forecast.

---

27 http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/Energy_Efficiency_2010-2012_Evaluation_Report.htm. EM&V results for 2013-15 are almost complete and will be used for the revised forecast, if available.

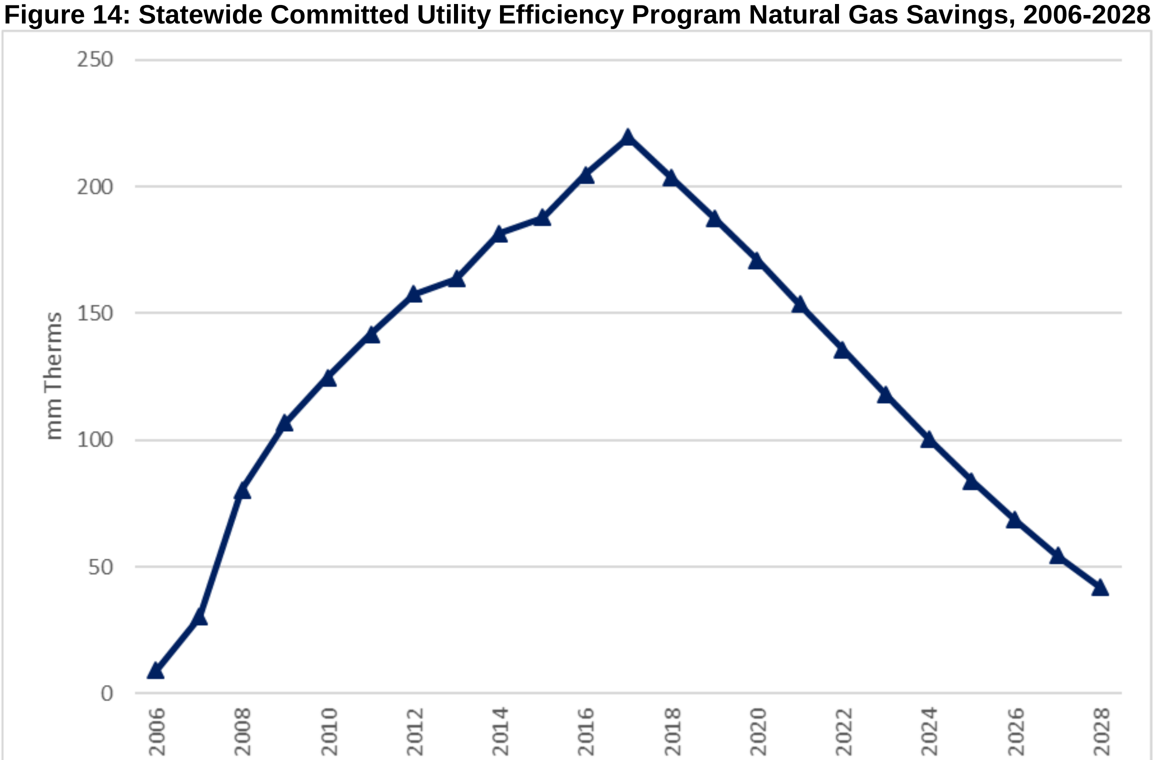
28 Staff did not develop forecast scenarios for committed program savings since this would have involved only new savings in 2017 and would have had a trivial impact on forecast results.

Figure 13: Statewide Committed Utility Efficiency Program Electricity Savings, 1990-2028



Source: California Energy Commission, Demand Analysis Office, 2017.

Figure 14: Statewide Committed Utility Efficiency Program Natural Gas Savings, 2006-2028



Source: California Energy Commission, Demand Analysis Office, 2017.

Staff was not able to put together total savings from committed building and appliance standards in time for this report. These will be included in the revised version of this forecast.

Light-Duty EVs

CED 2017 Preliminary incorporates a new light-duty EV forecast, developed by the Transportation Energy Forecasting Unit of the Demand Analysis Office in June 2017. The EV forecast incorporates a new vehicle choice survey, completed in spring 2017 and includes projections of pure battery-electric (BEV) and plug-in hybrid vehicles (PHEV) in both the residential and nonresidential sectors.[29] Three scenarios were developed, with assumptions consistent with the three demand cases.

Unlike past EV forecasts, the new version easily meets the ZEV requirements as modeled in CARB's most recent compliance case[30] in all three scenarios. Range projections for BEVs are much more optimistic than in the recent past; therefore, each vehicle is assigned more ZEV credits. This means fewer vehicles required to meet ZEV compliance.

The state forecast for EVs was distributed to the electricity planning areas using Department of Motor Vehicle registration data at the zip code level and assuming current planning area shares for EV ownership remain constant over the forecast period. Electricity consumption was developed for each planning area by mapping county vehicle miles traveled per vehicle data from CARB to the planning areas and applying these estimates to projected EV stock.

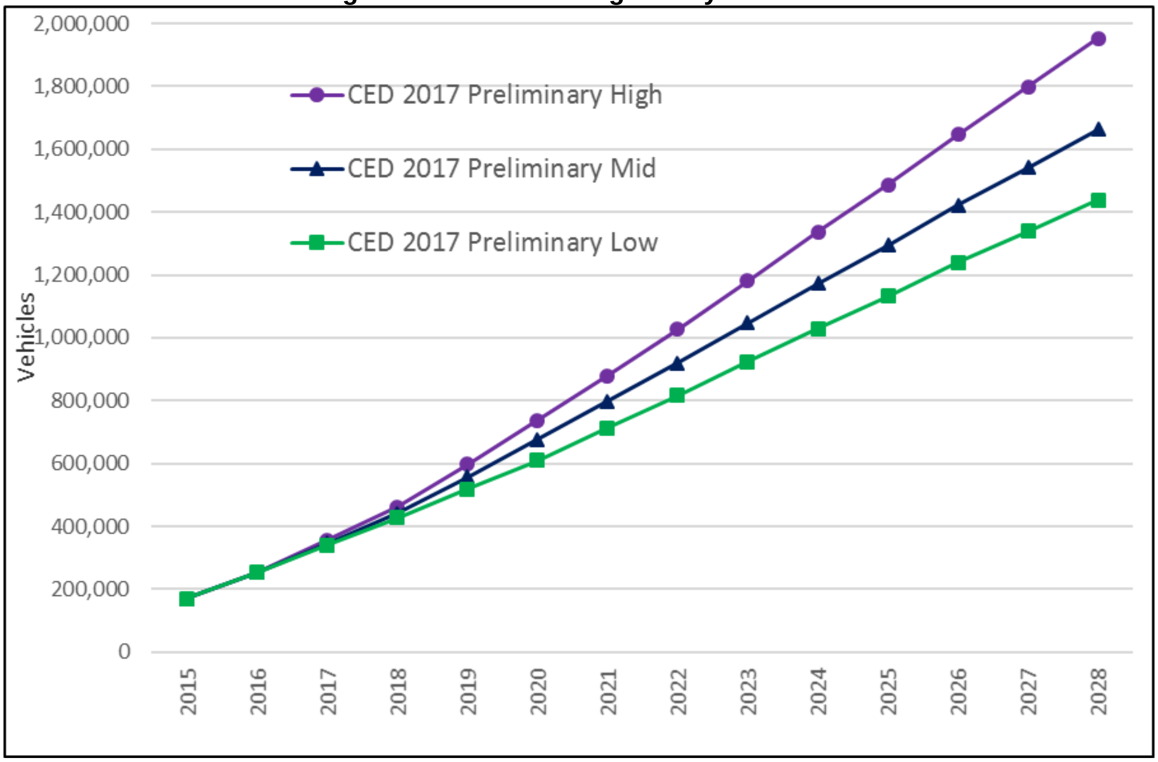
Figure 15 shows the light-duty EV stock forecast by scenario. In the demand mid case, projected stock reaches more than 1.6 million vehicles in 2028, of which 57 percent are BEVs.[31] **Figure 16** shows the electricity consumption attributable to these vehicles, reaching more than 6,000 GWh by 2028.

29 Details on the vehicle choice forecasts are available here: http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-05/TN219810_20170620T141018_Transportation_Energy_Demand_Forecast_20172030.pdf.

30 For a summary of the compliance case, see https://www.arb.ca.gov/msprog/acc/mtr/acc_mtr_summaryreport.pdf.

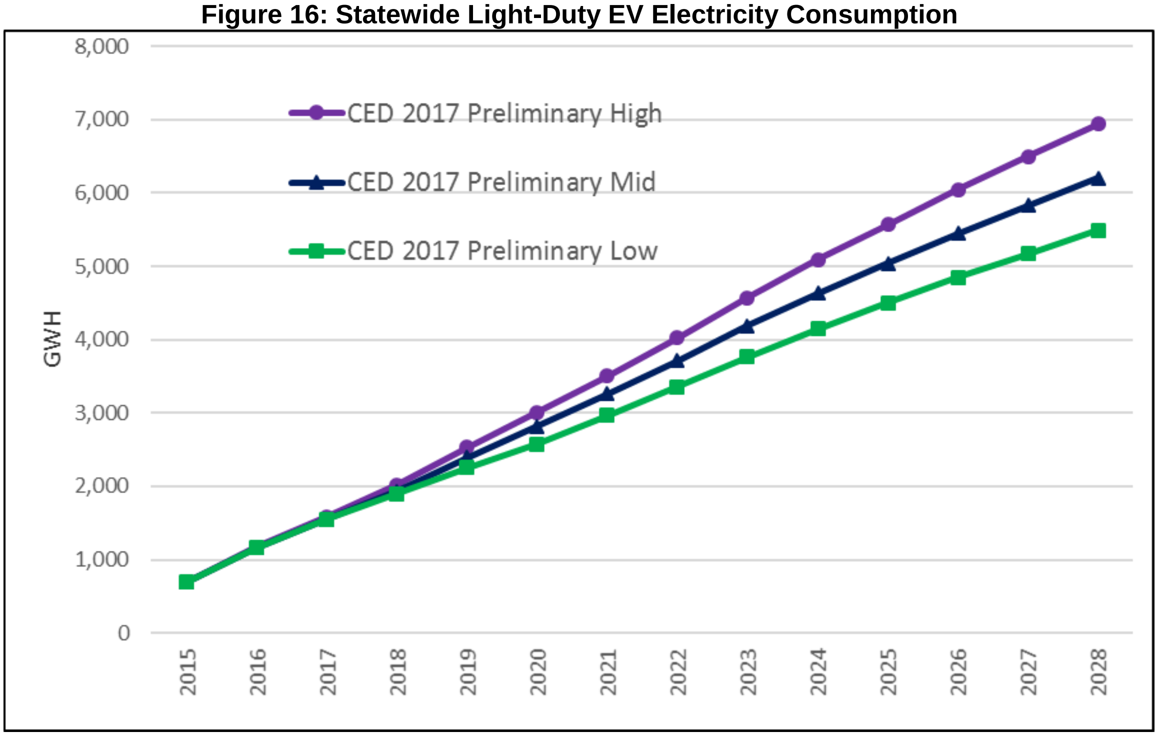
31 Ratios are similar in the high and low cases, 58 percent and 54 percent, respectively.

Figure 15: Statewide Light-Duty EV Stock



Source: California Energy Commission, Demand Analysis Office, 2017.

Figure 16: Statewide Light-Duty EV Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2017.

Other Transportation Electrification

Significant increases in other transportation-related electricity use in California are expected to occur through port, truck stop, and other electrification. In particular, regulations implemented by the CARB[32] are aimed at reducing emissions from container, passenger, and refrigerated cargo vessels docked at California ports. Electrification impacts projected for *CED 2015* were based on a 2015 consultant study for the Energy Commission, [33] which examined the potential for additional electrification in airport ground support equipment, port cargo handling equipment, shore power,[34] truck stops, forklifts, and transportation refrigeration units. For *CED 2017 Preliminary*, staff updated these impacts by incorporating new assumptions for gross state product (from the same Moody's forecasts discussed above), which drive increases in stock, and by extending the time frame out to 2030. In addition, the growth rate for transportation refrigeration units was reduced by 50 percent based on revised estimates of recent growth.

As in *CED 2015*, transportation electrification includes high, mid, and low scenarios, representing aggressive, most likely, and minimal increases in electrification, respectively. Electrification impacts from the study were quantified at the state level. To incorporate them into the baseline forecast, it was necessary to allocate impacts across sector and planning area. Electrification impacts from port cargo handling equipment, shore power, truck stop electrification, and airport ground support were added to the transportation, communication, and utilities (TCU) sector. Impacts for transport refrigeration units and forklifts were assigned to multiple sectors, including industrial, TCU, and certain commercial building types. Given that some portion of electrification is already embedded in *CED 2017 Preliminary* through extrapolation of historical trends, staff estimated *incremental* impacts of the updated projections.[35] The statewide impacts in each forecast year were distributed based on the relative shares of total electricity use projected for each sector and planning area.

The statewide incremental electrification impacts incorporated in *CED 2015 Revised* are shown in **Table 8**. Most of the impacts come from forklifts and shore power; together, these applications account for around 80 percent of the total.

---

32 *Airborne Toxic Control Measure For Auxiliary Diesel Engines Operated On Ocean-Going Vessels At-Berth in a California Port.* Adopted in 2007.

33 The study was conducted by the University of California, Davis, Institute of Transportation and Aspen Environmental Group. The final report is available here: http://www.energy.ca.gov/2016publications/CEC-200-2016-014/CEC-200-2016-014.pdf.

34 Power required for basic ship operations when berthed.

35 For example, shore power electricity would increase at roughly the rate of population growth within the TCU sector in the baseline forecast. Incremental impacts were calculated by applying population growth to current shore power estimates and then subtracting the results from the updated projections.

Table 8: Additional Electrification, Statewide (GWh)

Technology	Demand	2017	2018	2020	2023	2026	2028
Airport Ground Support Equipment	High	4	7	12	20	29	36
	Mid	3	4	8	13	19	24
	Low	2	3	4	7	10	13
Port Cargo Handling Equipment	High	18	29	55	105	175	240
	Mid	9	14	26	51	84	116
	Low	4	7	13	25	41	56
Shore Power	High	106	147	243	282	331	352
	Mid	96	124	185	208	239	255
	Low	96	114	157	175	201	216
Truck Stops	High	3	5	9	17	28	28
	Mid	2	2	5	9	14	14
	Low	0	0	0	0	1	1
Forklifts	High	94	146	260	445	660	688
	Mid	56	86	151	257	382	398
	Low	0	0	0	0	0	0
Transportation Refrigeration Units	High	30	46	82	141	206	236
	Mid	4	6	11	19	28	34
	Low	0	0	1	1	1	1
Total	High	254	380	661	1,011	1,429	1,580
	Mid	169	237	386	557	767	841
	Low	103	124	175	208	254	287

Source: California Energy Commission, Demand Analysis Office, 2017.

Climate Change

To estimate the potential of future climate change to increase electricity and natural gas consumption and peak demand,[36] staff uses temperature scenarios developed by the Scripps Institute of Oceanography through a set of global climate change models, where results are downscaled to 50-square-mile grids in California. From these options, staff develops high and average temperature increase scenarios to correspond to the high and mid demand forecast cases, respectively. The low demand case assumes no additional impacts from climate change. The remaining two scenarios are applied to weather-sensitive econometric models for residential and commercial sector consumption[37] and for peak demand to estimate consumption and peak impacts for each planning area and forecasting zone.

New temperature scenarios were not delivered in time for *CED 2017 Preliminary* but will be applied in the revised version of this forecast. Therefore, as a placeholder, staff used

36 Estimates should be considered incremental, to the extent that climate change has already had an effect on energy use.

37 Other sectors show no significant temperature sensitivity for consumption.

the same estimates developed for *CED 2015*,[38] extrapolating out to 2028. Extrapolation results in estimated increases in electricity consumption of around 925 GWh and 800 GWh in the high and mid demand cases, respectively, by 2028. Peak demand impacts reach 1,000 MW and 640 MW in 2028, while natural gas consumption, because of less heating need, is reduced by 200 million therms and 170 million therms, respectively.

Demand Response

The term "demand response" encompasses a variety of programs, including traditional direct control (interruptible) programs and new price-responsive demand programs. A key distinction is whether the program is dispatchable, or event-based. Dispatchable programs, such as direct control, interruptible tariffs, or demand bidding programs, have triggering conditions that are not under the control of and cannot be anticipated by the customer. Nonevent-based programs are not activated using a predetermined threshold condition, which allows the customer to make the economic choice whether to modify its usage in response to ongoing price signals. Impacts from such nonevent-based programs have traditionally been included in the IEPR demand forecasts. More specifically, expected impacts incremental to the last historical year for peak (2016) affect the demand forecast.[39]

Energy or peak load saved from dispatchable or event-based programs has traditionally been treated as a resource and, therefore, not accounted for in the demand forecast. However, the CPUC and California ISO support a "bifurcation," or splitting in two, of such programs based on whether the resource can be integrated into the California ISO's energy market. This means that event-based demand response resources are now divided into load-modifying (demand-side) and California ISO-integrated supply-side programs. Currently, the demand forecast incorporates two types of pricing programs, critical peak pricing and peak time rebates, designated as load-modifying. More programs may be assigned this designation in the future.

Staff bases demand response estimates on annual IOU demand response filings.[40] Projected nonevent-based program impacts are shown in **Table 9** and event-based program impacts from the two pricing programs in **Table 10**, by IOU. Combined impacts from these programs reach 206 MW for PG&E, 96 MW for SCE, and 27 MW for SDG&E by 2028. The total (noncoincident) reduction over all utilities from critical peak pricing, peak-time rebate, and nonevent programs amounts to 329 MW in 2028.

---

38 See Kavalec, Chris, Nick Fugate, Cary Garcia, and Asish Gautam. *2016. California Energy Demand 2016-2026, Revised Electricity Forecast. California* Energy Commission, pp. 44-46. Publication Number: CEC-200-2016-001-V1. Available at http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf.

39 Incremental impacts only would be counted since historical peaks would incorporate reductions in demand that currently occur.

40 PG&E, SCE, and SDG&E *2016 Portfolio Summary Load Impact Reports*, 4/3/2017. Summaries available for SDG&E http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M185/K575/185575936.PDF; SCE http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M185/K576/185576373.PDF; and PG&E https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=406814.

Table 9: Estimated Nonevent-Based Demand Response Program Impacts (MW)

Year	PG&E	SCE	SDG&E
2016	0	0	0
2017	8	1	3
2018	20	5	3
2019	32	7	3
2020	40	7	4
2021	56	7	4
2022	66	8	5
2023	78	8	5
2024	91	8	6
2025	102	8	6
2026	114	8	6
2027	126	8	6
2028*	126	8	6
*Program cycles end in 2027; 2028 values assumed the same as 2027.			

Source: California Energy Commission, Demand Analysis Office, 2017.

Table 10: Estimated Demand Response Program Impacts: Critical Peak Pricing and Peak-Time Rebate Programs (MW)

Year	PG&E	SCE	SDG&E
2016	48	61	61
2017	61	28	18
2018	74	36	18
2019	75	46	18
2020	77	65	19
2021	78	58	20
2022	78	63	20
2023	78	68	21
2024	79	73	21
2025	79	78	21
2026	79	83	21
2027	80	88	21
2028*	80	88	21
*Program cycles end in 2027; 2028 values assumed the same as 2027.			

Source: California Energy Commission, Demand Analysis Office, 2017.

Residential TOU programs, currently small-scale and limited, are included in the nonevent-based program estimates. However, these programs are expected to be expanded significantly beginning in 2019. For the revised version of this forecast, staff plans to incorporate large-scale residential TOU as planned within the hourly load forecasting model.

CHAPTER 2: Electricity and Natural Gas Planning Area Results

This chapter summarizes forecast results for the five major electricity planning areas in California: PG&E (electricity and natural gas), SCE, SDG&E, NCNC, and LADWP. In addition, results are described for the three major natural gas planning areas: PG&E, SoCal Gas, and SDG&E. Comprehensive results for the planning areas and climate zones, including economic/demographic assumptions, rates, self-generation and PV impacts, and EV results are available electronically as a set of forms posted with this report.[41]

PG&E Electricity Planning Area

The PG&E electricity planning area includes:

- PG&E bundled retail customers.
- Customers served by energy service providers and community choice aggregators using the PG&E distribution system to deliver electricity to end users.
- Customers of POUs and other providers in the PG&E TAC area (**Table 4**).

Key factors incorporated in the forecast include the following:

- Projected population growth averages 0.96 percent per year over 2015-2028, higher than the average for the state as a whole (0.81 percent). Projected growth in the number of households in the mid case averages 1.09 percent per year, also higher than the state average (0.99 percent).
- Per capita income growth averages 2.05 percent per year from 2015-2028, slightly higher than the state average (1.98 percent).
- EV electricity consumption by 2028 is projected to be about 2,700 GWh, 2,400 GWh, and 2,100 GWh in the high, mid, and low demand cases, respectively.
- Projected behind-the-meter PV installed capacity reaches 7,400 MW, 7,700 MW and 8,800 MW in the high, mid, and low demand cases, respectively, by 2028.
- Demand response programs considered in this forecast reduce peak demand by 206 MW in 2028.

The *CED 2017 Preliminary* high, mid, and low demand case results for electricity consumption and peak demand for selected years are shown in **Table 11**, along with the

41 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-03.

mid case from *CEDU 2016*. With a lower EV forecast and slightly slower projected growth in population, average annual growth in consumption (2015-2027) in the new mid case is lower than in the *CEDU 2016*. By 2027, *CEDU 2016* assumed more than 3,000 GWh of electricity consumption from EVs in the mid case, compared to around 2,300 GWh for *CED 2017 Preliminary*. A higher PV forecast reduces peak demand growth in the *CED 2017 Preliminary* mid case versus *CEDU 2016*. Peak impacts from PV are projected to be more than 2,450 MW in 2027 in the *CED 2017 Preliminary* mid case, compared to around 2,050 MW in *CEDU 2016*.

Table 11: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of PG&E Electricity Demand

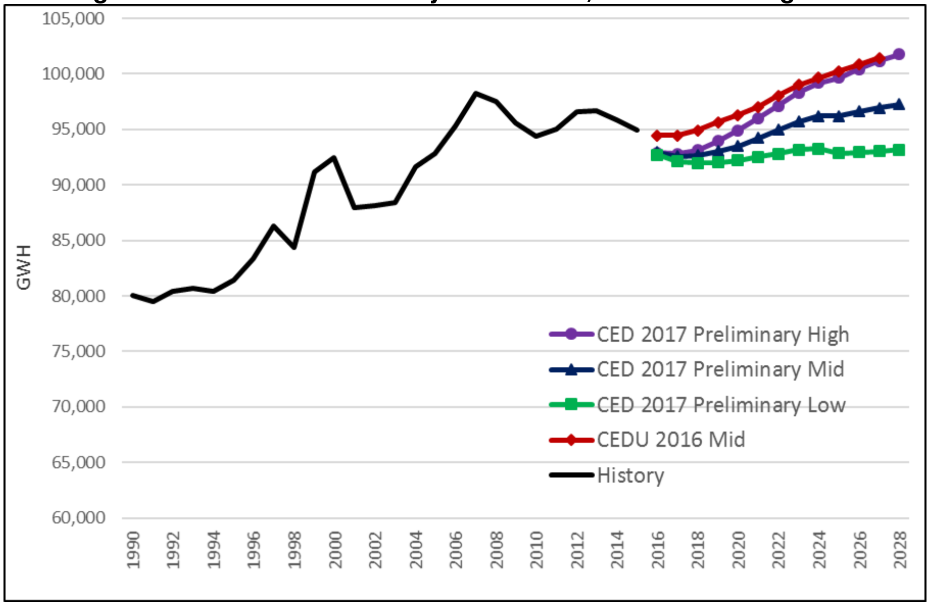
Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	83,978	83,996	83,996	83,996
2000	96,609	96,611	96,611	96,611
2015	104,868	104,548	104,548	104,548
2020	109,725	109,869	108,581	107,639
2025	116,816	117,975	115,113	113,266
2027	119,633	120,761	117,263	115,087
2028	--	121,972	118,241	115,935
	Average Annual Growth Rates			
1990-2000	1.41%	1.41%	1.41%	1.41%
2000-2015	0.55%	0.53%	0.53%	0.53%
2015-2020	0.91%	1.00%	0.76%	0.58%
2015-2027	1.10%	1.21%	0.96%	0.80%
2015-2028	--	1.19%	0.95%	0.80%
Noncoincident Peak (MW)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	15,899	15,899	15,899	15,899

Consumption (GWh)				
2000	18,980	18,980	18,980	18,980
2016*	21,141	21,194	21,194	21,194
2020	21,597	21,635	21,396	20,975
2025	22,317	22,538	21,763	20,821
2027	22,533	22,842	21,857	20,755
2028	--	22,971	21,904	20,736
	Average Annual Growth Rates			
1990-2000	1.79%	1.79%	1.79%	1.79%
2000-2016	0.68%	0.69%	0.69%	0.69%
2016-2020	0.54%	0.52%	0.24%	-0.26%
2016-2027	0.58%	0.68%	0.28%	-0.19%
2016-2028	--	0.67%	0.27%	-0.18%
Actual historical values are shaded.				
*Weather normalized: the forecasts use a weather-normalized peak value derived from the actual 2016 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2017.

Projected electricity sales for the three *CED 2017 Preliminary* cases and the *CEDU 2016* mid demand case for PG&E are shown in **Figure 17**. All three new forecast cases are lower than the *CEDU 2016* mid case throughout the forecast period, reflecting higher projected self-generation energy impacts and, at the beginning of the forecast period, additional committed efficiency program savings. By 2027, PV reduces sales by around 12,300 GWh in the *CED 2017 Preliminary* mid case compared to 10,200 GWh in *CEDU 2016*. Annual growth from 2015-2027 for the *CED 2017 Preliminary* forecast averages 0.53 percent, 0.17 percent, and -0.17 percent in the high, mid and low cases, respectively, compared to 0.51 percent in the *CEDU 2016* mid case.

Figure 17: Historical and Projected Sales, PG&E Planning Area



Source: California Energy Commission, Demand Analysis Office, 2017.

SCE Planning Area

The SCE planning area includes:

- SCE bundled retail customers.
- Customers served by energy service providers using the SCE distribution system to deliver electricity to end users.
- Customers of the various Southern California municipal and irrigation district utilities within the SCE TAC area (**Table 4**).

Key factors incorporated in the forecast include the following:

- Projected population growth averages 0.69 percent per year over 2015-2028, lower than the average for the state as a whole (0.81 percent). Projected growth in the number of households in the mid case averages 0.92 percent per year, also lower than the state average (0.99 percent).
- Per capita income growth averages 1.87 percent per year from 2015-2028, lower than the state average (1.98 percent).
- EV electricity consumption by 2028 is projected to be about 2,300 GWh, 2,000 GWh, and 1,800 GWh in the high, mid, and low demand cases, respectively.
- Projected behind-the-meter PV installed capacity reaches 6,000 MW, 6,300 MW and 7,400 MW in the high, mid, and low demand cases, respectively, by 2028.
- Demand response programs considered in this forecast reduce peak demand by 96 MW by 2028.

The *CED 2017 Preliminary* high, mid, and low demand case results for electricity consumption and peak demand for selected years are shown in **Table 12**, along with the mid case from *CEDU 2016*. Average annual growth in consumption from 2015-2027 in the new mid case is higher than in the *CEDU 2016* mid case in spite of a lower EV forecast because of the lack of additional lighting savings after 2017 (as discussed in **Chapter 1**), fueling faster growth in the residential sector. In addition, growth in manufacturing electricity use is higher in the mid case compared to *CEDU 2016*. A higher PV forecast reduces peak demand growth in the *CED 2017 Preliminary* mid case versus *CEDU 2016*. Peak impacts from PV are projected to be around 2,200 MW in 2027 in the *CED 2017 Preliminary* mid case, compared to about 1,900 MW in *CEDU 2016*.

Table 12: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of SCE Electricity Demand

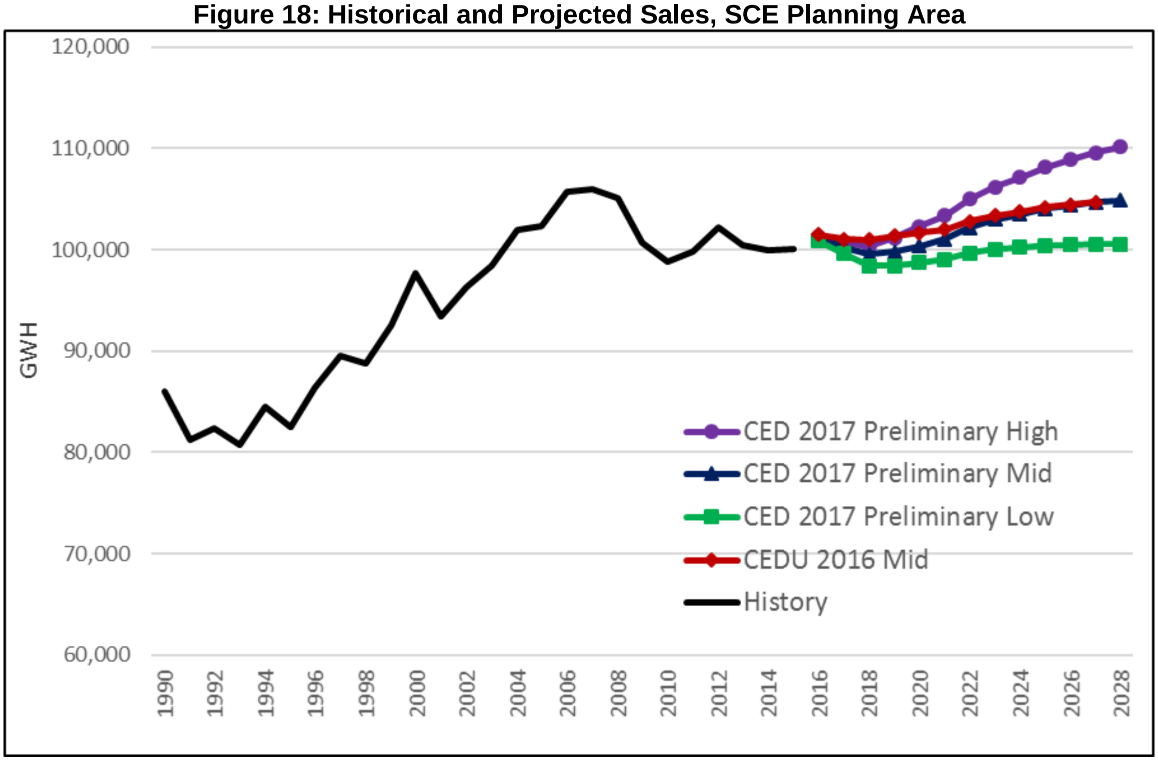
Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	89,041	89,041	89,041	89,041
2000	100,815	100,815	100,815	100,815
2015	106,080	106,140	106,140	106,140
2020	111,168	112,685	110,753	109,449
2025	116,697	121,537	117,899	115,828
2027	118,803	124,274	119,902	117,588
2028	--	125,467	120,780	118,347
	Average Annual Growth Rates			
1990-2000	1.25%	1.25%	1.25%	1.25%
2000-2015	0.34%	0.34%	0.34%	0.34%
2015-2020	0.94%	1.20%	0.85%	0.62%
2015-2027	0.95%	1.32%	1.02%	0.86%
2015-2028	--	1.30%	1.00%	0.84%
Noncoincident Peak (MW)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	17,970	17,970	17,970	17,970
2000	19,829	19,829	19,829	19,829
2016*	22,224	22,191	22,191	22,191
2020	22,296	21,597	21,201	21,000
2025	22,563	22,638	21,684	20,985
2027	22,556	22,883	21,705	20,867
2028	--	22,975	21,699	20,799
	Average Annual Growth Rates			

Consumption (GWh)				
1990-2000	0.99%	0.99%	0.99%	0.99%
2000-2016	0.72%	0.71%	0.71%	0.71%
2016-2020	0.08%	-0.68%	-1.13%	-1.37%
2016-2027	0.13%	0.28%	-0.20%	-0.56%
2016-2028	--	0.29%	-0.19%	-0.54%
Actual historical values are shaded.				
*Weather normalized: the forecasts use a weather-normalized peak value derived from the actual 2016 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2017.

Projected electricity sales for the three *CED 2017 Preliminary* cases and the *CEDU 2016* mid demand case for the SCE planning area are shown in **Figure 18**. The new mid case begins below *CEDU 2016* mid as new efficiency program savings are added and more electricity is generated from PV. However, faster growth in consumption in the middle of the forecast period allows the new mid case to reach *CEDU 2016* levels by 2027. Annual growth from 2015–2027 for the *CED 2017 Preliminary* forecast averages 0.76 percent, 0.38 percent, and 0.04 percent in the high, mid, and low cases, respectively, compared to 0.38 percent in the *CEDU 2016* mid case.

Figure 18: Historical and Projected Sales, SCE Planning Area



Source: California Energy Commission, Demand Analysis Office, 2017.

SDG&E Electricity Planning Area

The SDG&E electricity planning area includes SDG&E bundled retail customers and customers served by various energy service providers using the SDG&E distribution system to deliver electricity to end users. The definition of this planning area has not changed from previous forecasts.

Key factors incorporated in the forecast include the following:

- Projected population growth averages 0.76 percent per year over 2015–2028, slightly lower than the average for the state as a whole (0.81 percent). Projected growth in the number of households in the mid case averages 0.96 percent per year, also slightly lower than the state average (0.99 percent).
- Per capita income growth averages 1.70 percent per year from 2015–2028, lower than the state average (1.98 percent).
- EV electricity consumption by 2028 is projected to be about 540 GWh, 480 GWh, and 420 GWh in the high, mid, and low demand cases, respectively.
- Projected behind-the-meter PV installed capacity reaches 1,800 MW, 1,900 MW, and 2,200 MW in the high, mid, and low demand cases, respectively, by 2028.
- Demand response programs considered in this forecast reduce peak demand by 27 MW by 2028.

The *CED 2017 Preliminary* high, mid, and low demand case results for electricity consumption and peak demand for selected years are shown in **Table 13**, along with the mid case from *CEDU 2016*. Average annual growth in consumption from 2015-2027 in the new mid case roughly matches that in the *CEDU 2016* mid case, as a slightly lower EV forecast along with slower growth in income compared to the previous forecast is balanced by the reduction in residential lighting savings (as discussed in **Chapter 1**). Although a higher PV forecast reduces peak demand growth in the *CED 2017 Preliminary* mid case, peak demand growth is slightly higher over 2016–2027 compared to *CEDU 2016*, a result of the adjustment to the load factors in 2016.[42] Peak impacts from PV are projected to be around 670 MW in 2027 in the *CED 2017 Preliminary* mid case, compared to about 570 MW in *CEDU 2016*.

42 Peak demand was historically low for SDG&E in 2016, even after weather normalization. Therefore, load factors (average load/peak load) in staff's Hourly Electricity Load Model required a significant upward adjustment to match the 2016 peak. After 2016, load factors returned to lower levels, shifting peak demand upward starting in 2017. Peak demand growth from 2017-2027 is lower in the new mid case compared to CEDU 2016, reflecting more PV peak impacts. Analysis of actual loads for summer 2017 will indicate whether peak demand in 2016 was indeed unusually low or a sign of more permanent change.

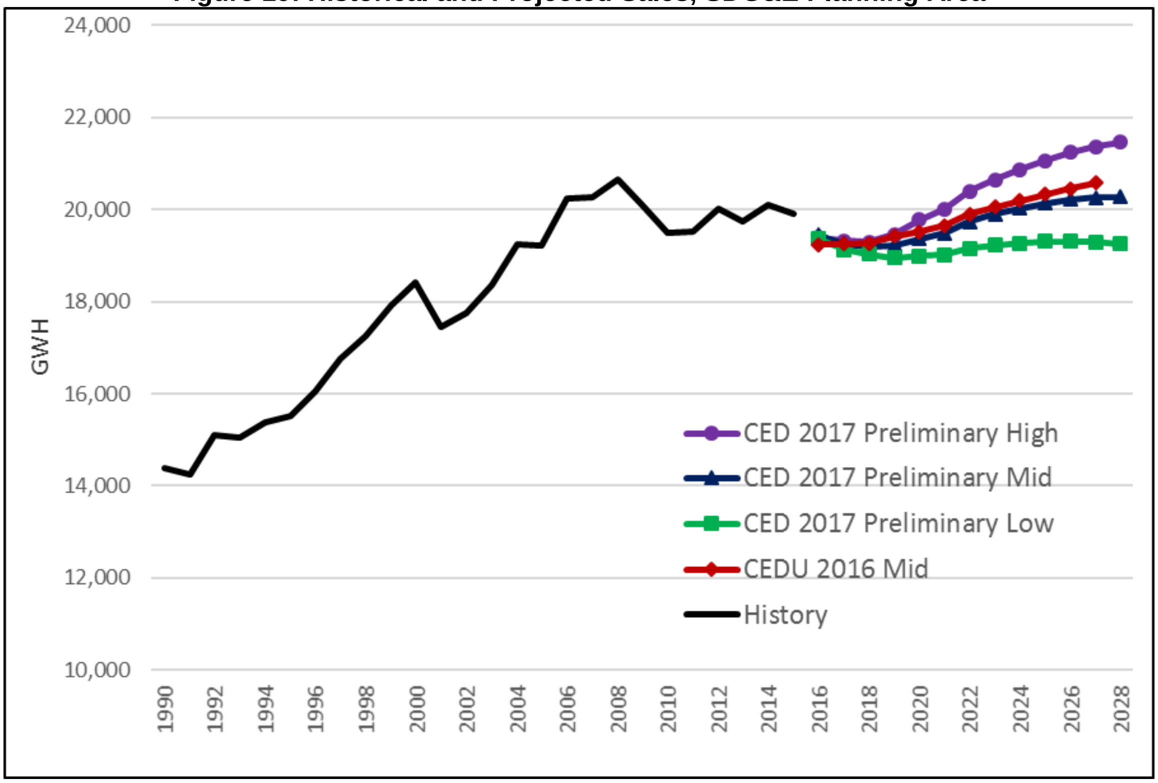
Table 13: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of SDG&E Electricity Demand

Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	14,857	14,857	14,857	14,857
2000	18,784	18,784	18,784	18,784
2015	21,308	21,505	21,505	21,505
2020	22,185	22,995	22,631	22,406
2025	23,744	24,898	24,159	23,758
2027	24,354	25,429	24,545	24,067
2028	--	25,649	24,695	24,179
	Average Annual Growth Rates			
1990-2000	2.37%	2.37%	2.37%	2.37%
2000-2015	0.84%	0.91%	0.91%	0.91%
2015-2020	0.81%	1.35%	1.03%	0.82%
2015-2027	1.12%	1.41%	1.11%	0.94%
2015-2028	--	1.36%	1.07%	0.91%
Noncoincident Peak (MW)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	2,978	2,978	2,978	2,978
2000	3,485	3,485	3,485	3,485
2016*	4,448	4,427	4,427	4,427
2020	4,455	4,624	4,548	4,460
2025	4,523	4,799	4,597	4,405
2027	4,530	4,824	4,576	4,355
2028	--	4,826	4,557	4,321
	Average Annual Growth Rates			
1990-2000	1.58%	1.58%	1.58%	1.58%
2000-2016	1.54%	1.51%	1.51%	1.51%
2016-2020	0.04%	1.09%	0.67%	0.18%
2016-2027	0.17%	0.78%	0.30%	-0.15%
2016-2028	--	0.72%	0.24%	-0.20%
Actual historical values are shaded.				
*Weather normalized: the forecasts use a weather-normalized peak value derived from the actual 2016 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2017.

The increase in self-generation impacts means lower sales in the mid case compared to *CEDU 2016* in the SDG&E planning area, as shown in **Figure 19**. By 2027, PV reduces sales by more than 3,100 GWh in the *CED 2017 Preliminary* mid case compared around 2,700 GWh in *CEDU 2016*. Annual growth from 2015-2027 for the *CED 2017 Preliminary* forecast averages 0.59 percent, 0.14 percent, and -0.27 percent in the high, mid, and low cases, respectively, compared to 0.36 percent in the *CEDU 2016* mid case.

Figure 19: Historical and Projected Sales, SDG&E Planning Area



Source: California Energy Commission, Demand Analysis Office, 2017.

NCNC Planning Area

The Northern California Non-California ISO planning area includes the Turlock Irrigation District control area and the Balancing Authority of Northern California. By far the largest utility in this planning area is SMUD. Separate demand forms are provided for NCNC and SMUD.[43]

Key factors incorporated in the forecast include the following:

- Projected population growth averages 1.19 percent per year over 2015–2028, higher than the average for the state as a whole (0.81 percent) and highest of any planning area except for IID. Projected growth in the number of households in

43 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-03.

the mid case averages 1.22 percent per year, also higher than the state average (0.99 percent).

- Per capita income growth averages 1.87 percent per year from 2015-2028, slightly lower than the state average (1.98 percent).
- EV electricity consumption by 2028 is projected to be about 265 GWh, 235 GWh, and 210 GWh in the high, mid, and low demand cases, respectively.
- Projected behind-the-meter PV installed capacity reaches 1,070 MW, 1,140 MW, and 1,340 MW in the high, mid, and low demand cases, respectively, by 2028.

The *CED 2017 Preliminary* high, mid, and low demand case results for electricity consumption and peak demand for selected years are shown in **Table 14**, along with the mid case from *CEDU 2016*. Average annual growth in consumption from 2015-2027 in the new mid case is lower than in the *CEDU 2016* mid case, mainly the result of a lower EV forecast along with slightly slower growth in income compared to the previous forecast. By 2027, *CEDU 2016* assumed around 370 GWh of electricity consumption from EVs in the mid case, compared to around 240 GWh for *CED 2017 Preliminary*. A higher PV forecast reduces peak demand growth in the *CED 2017 Preliminary* mid case versus *CEDU 2016*. Peak impacts from PV are projected to be about 385 MW in 2027 in the *CED 2017 Preliminary* mid case, compared to around 200 MW in *CEDU 2016*.

Table 14: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of NCNC Electricity Demand

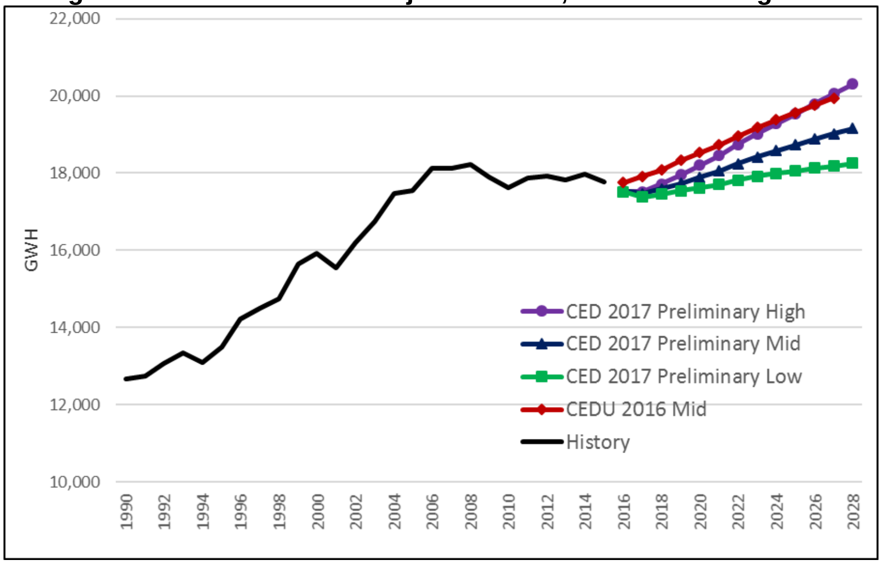
Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	12,702	12,672	12,672	12,672
2000	15,996	15,917	15,917	15,917
2015	17,912	18,061	18,061	18,061
2020	19,050	19,121	18,831	18,605
2025	20,405	21,030	20,319	19,872
2027	20,956	21,759	20,847	20,313
2028	--	22,109	21,103	20,529
	Average Annual Growth Rates			
1990-2000	2.33%	2.31%	2.31%	2.31%
2000-2015	0.76%	0.85%	0.85%	0.85%
2015-2020	1.24%	1.15%	0.84%	0.60%
2015-2027	1.32%	1.56%	1.20%	0.98%
2015-2028	--	1.57%	1.20%	0.99%
Noncoincident Peak (MW)				

Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	3,731	3,731	3,731	3,731
2000	4,516	4,516	4,516	4,516
2016*	4,991	4,991	4,991	4,991
2020	5,233	5,263	5,171	5,041
2025	5,519	5,681	5,431	5,189
2027	5,626	5,845	5,521	5,234
2028	--	5,925	5,565	5,256
	Average Annual Growth Rates			
1990-2000	1.93%	1.93%	1.93%	1.93%
2000-2016	0.63%	0.63%	0.63%	0.63%
2016-2020	1.19%	1.34%	0.89%	0.25%
2016-2027	1.10%	1.45%	0.92%	0.43%
2016-2028	--	1.44%	0.91%	0.43%
Actual historical values are shaded.				
*Weather normalized: the forecasts use a weather-normalized peak value derived from the actual 2016 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2017.

Projected electricity sales for the three *CED 2017 Preliminary* cases and the *CEDU 2016* mid demand case for NCNC are shown in **Figure 20**. All three new forecast cases are lower than the *CEDU 2016* mid case in 22027, reflecting higher projected self-generation energy impacts and, at the beginning of the forecast period, additional committed efficiency program savings. By 2027, PV reduces sales by almost 1,900 GWh in the *CED 2017 Preliminary* mid case compared to slightly less than 1,000 GWh in *CEDU 2016*. Annual growth from 2015-2027 for the *CED 2017 Preliminary* forecast averages 1.02 percent, 0.57 percent, and 0.20 percent in the high, mid and low cases, respectively, compared to 1.04 percent in the *CEDU 2016* mid case.

Figure 20: Historical and Projected Sales, NCNC Planning Area



Source: California Energy Commission, Demand Analysis Office, 2017.

LADWP Planning Area

The LADWP planning area includes LADWP bundled retail customers and customers served by energy service providers using the LADWP distribution system to deliver electricity to end users.

Key factors incorporated in the forecast include the following:

- Projected population growth averages 0.54 percent per year over 2015-2028, lower than the average for the state as a whole (0.81 percent) and lowest of any planning area except for BUGL. Projected growth in the number of households in the mid case averages 0.74 percent per year, also lower than the state average (0.99 percent).
- Per capita income growth averages 2.32 percent per year from 2015-2028, lower than the state average (1.98 percent).
- EV electricity consumption by 2028 is projected to be about 960 GWh, 860 GWh, and 770 GWh in the high, mid, and low demand cases, respectively.
- Projected behind-the-meter PV installed capacity reaches 690 MW, 670 MW, and 670 MW in the high, mid, and low demand cases, respectively, by 2028.

CED 2017 Preliminary high, mid, and low demand scenarios are compared with the *CEDU 2016* mid demand scenario in **Table 15** for electricity consumption and peak demand for selected years. Based on an adjustment to the QFER data for 2015, consumption starts the forecast period significantly below *CEDU 2016*. Thereafter, growth is similar in the new mid case compared to *CEDU 2016*, as lower projected population growth is roughly balanced by a slightly higher EV forecast, slightly faster income growth, and less residential lighting savings in the latter part of the forecast period. Growth in peak demand (2016-2027) is also similar in the new mid demand case versus *CEDU 2016* as a marginal increase in PV peak impacts (270 MW vs. 210 MW in 2027) is erased by slightly higher growth in peak end-use load.

Table 15: Comparison of *CED 2017 Preliminary* and *CEDU 2016* Mid Case Demand Baseline Forecasts of LADWP Electricity Demand

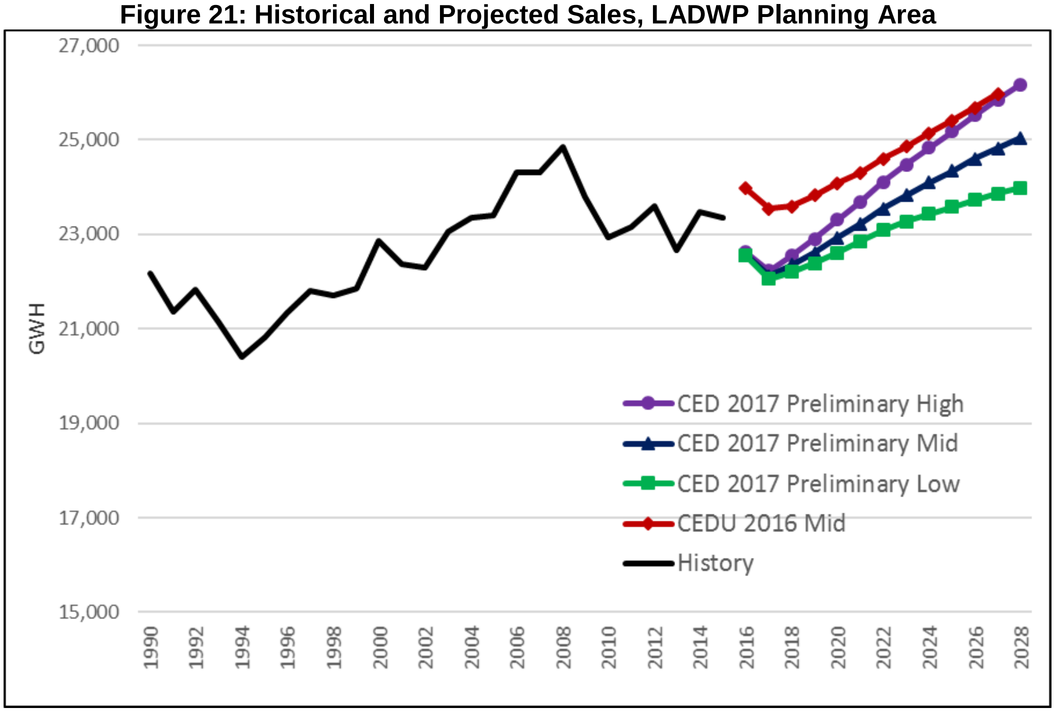
Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	23,038	23,038	23,038	23,038
2000	24,014	24,014	24,014	24,014
2015	25,570	24,870	24,870	24,870
2020	26,365	25,761	25,360	25,028
2025	27,996	27,986	27,137	26,364
2027	28,706	28,793	27,741	26,774
2028	--	29,175	28,023	26,958
	Average Annual Growth Rates			
1990-2000	0.42%	0.42%	0.42%	0.42%
2000-2015	0.42%	0.23%	0.23%	0.23%
2015-2020	0.61%	0.71%	0.39%	0.13%
2015-2027	0.97%	1.23%	0.91%	0.62%
2015-2028	--	1.24%	0.92%	0.62%
Noncoincident Peak (MW)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	5,341	5,341	5,341	5,341
2000	5,344	5,344	5,344	5,344
2016*	5,968	5,968	5,968	5,968
2020	6,019	6,064	6,004	5,868
2025	6,208	6,424	6,245	5,991
2027	6,282	6,549	6,316	6,009
2028	--	6,605	6,345	6,011
	Average Annual Growth Rates			
1990-2000	0.01%	0.01%	0.01%	0.01%
2000-2016	0.69%	0.69%	0.69%	0.69%
2016-2020	0.21%	0.40%	0.15%	-0.42%
2016-2027	0.47%	0.85%	0.52%	0.06%
2016-2028	--	0.85%	0.51%	0.06%
Actual historical values are shaded.				
*Weather normalized: the forecasts use a weather-normalized peak value derived from				

Consumption (GWh)
the actual 2016 peak for calculating growth rates during the forecast period.

Source: California Energy Commission, Demand Analysis Office, 2017.

Projected electricity sales for the three *CED 2017 Preliminary* cases and the *CEDU 2016* mid demand case for the LADWP planning area are shown in **Figure 21**. The noticeable difference in 2016 sales between *CED 2017 Preliminary* and *CEDU 2016* reflects the QFER adjustment for 2015. Sales dip in 2017 as self-generation increases significantly based on planned increases in distributed generation across various sectors.[44] From 2017-2027, sales growth is similar in the two mid cases. Annual growth from 2015-2027 for the *CED 2017 Preliminary* forecast averages 0.85 percent, 0.51 percent, and 0.18 percent in the high, mid, and low cases, respectively, compared to 0.65 percent in the *CEDU 2016* mid case.

Figure 21: Historical and Projected Sales, LADWP Planning Area



Source: California Energy Commission, Demand Analysis Office, 2017.

PG&E Natural Gas Planning Area

The PG&E natural gas planning area is defined as the combined PG&E and NCNC electric planning areas. It includes all PG&E retail gas customers, customers of private marketers using the PG&E natural gas distribution system, and the city of Palo Alto gas customers.

Table 16 compares the *CED 2017 Preliminary* demand cases with the *CED 2015* mid case for PG&E for selected years. As discussed in **Chapter 1**, 2016 was a very warm year

44 To be reevaluated for the revised forecast.

across the state, with a very low number of heating degree days. Thus, the 2016 forecast from *CED 2015* is a significant overprediction by almost 300 mm therms. In 2017, with historically average weather, the new mid forecast increases to almost match *CED 2015*. Afterward, consumption grows at a slightly slower rate than the *CED 2015* mid case, a result of lower population growth compared to that predicted for *CED 2015*. Overall, because of this jump in 2017, average annual consumption growth from 2016–2026 is higher in the new mid case than CED 2015.

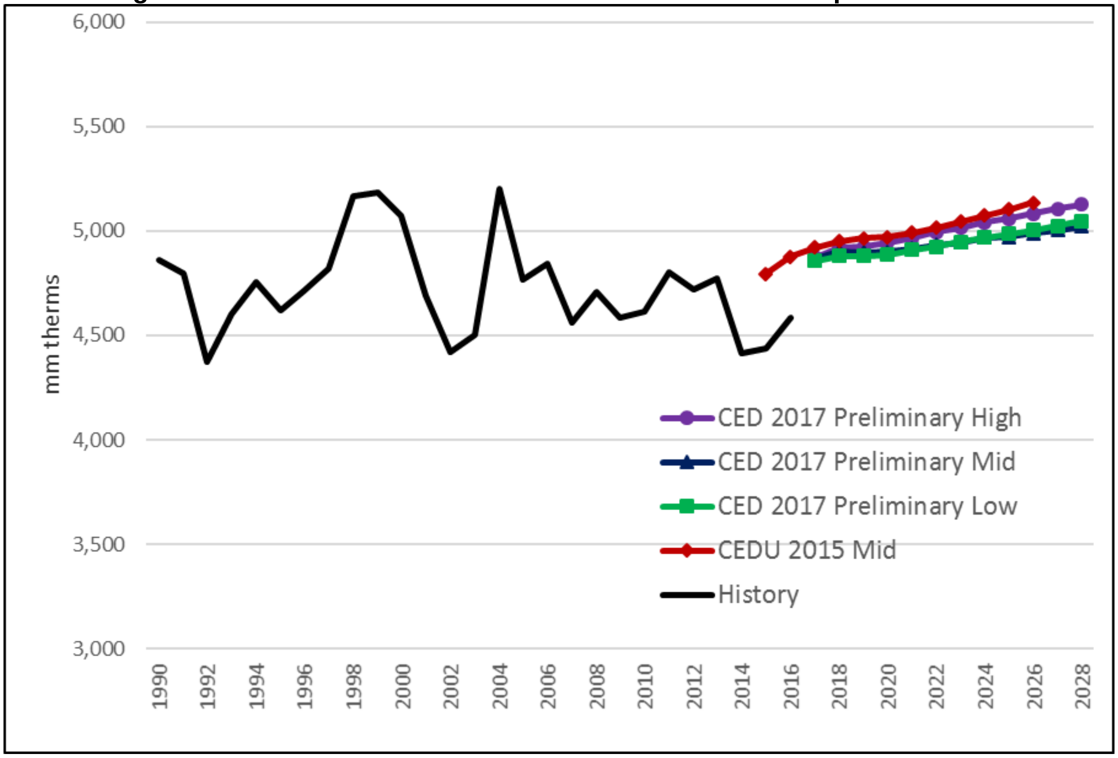
Table 16: Comparison of *CED 2017 Preliminary* and *CED 2015* Mid Case Demand Baseline Forecasts of PG&E End-User Natural Gas Consumption

Natural Gas Consumption (mm therms)				
	CED 2015 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	5,274	4,859	4,859	4,859
2000	5,291	5,074	5,074	5,074
2016	4,876	4,587	4,587	4,587
2020	4,972	4,945	4,902	4,886
2025	5,102	5,058	4,972	4,986
2026	5,135	5,082	4,989	5,004
2028	--	5,126	5,019	5,048
	Average Annual Growth Rates			
1990-2000	0.03%	0.43%	0.43%	0.43%
2000-2016	-0.54%	-0.67%	-0.67%	-0.67%
2016-2020	0.49%	1.90%	1.67%	1.59%
2016-2026	0.52%	1.03%	0.84%	0.87%
2016-2028	--	0.93%	0.75%	0.80%
Actual historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2017.

Figure 22 shows the three *CED 2017 Preliminary* cases and the *CED 2015* mid demand case. The projected jump in consumption in 2017 is noticeable, as is the *CED 2015* overprediction in 2016. The graph also shows the effect of climate change impacts, as the low demand case (with no climate change) overtakes the mid case by the end of the forecast period. Annual growth from 2016–2026 for the *CED 2017 Preliminary* forecast averages 1.03 percent, 0.84 percent, and 0.87 percent in the high, mid, and low cases, respectively, compared to 0.52 percent in the *CED 2015* mid case.

Figure 22: PG&E Baseline End-User Natural Gas Consumption Demand



Source: California Energy Commission, Demand Analysis Office, 2017.

SoCal Gas Planning Area

The SoCal Gas planning area is composed of the SCE, BUGL, IID, and LADWP electric planning areas. It includes customers of those utilities, city of Long Beach customers, customers of private marketers using the SoCal Gas natural gas distribution system, as well as customers served directly by the Northwest and Mojave pipeline companies.

Table 17 compares the *CED 2017 Preliminary* demand cases with the *CED 2015* mid case for SoCal Gas for selected years. The story at the beginning of the forecast period is similar to that of PG&E, with a *CED 2015* overprediction of around 210 mm therms in 2016 and a 2017 jump for *CED 2017 Preliminary* to match *CED 2015* levels. Afterward, consumption grows at a slightly slower rate than the *CED 2015* mid case, again a result of lower population growth compared to that predicted for *CED 2015*.

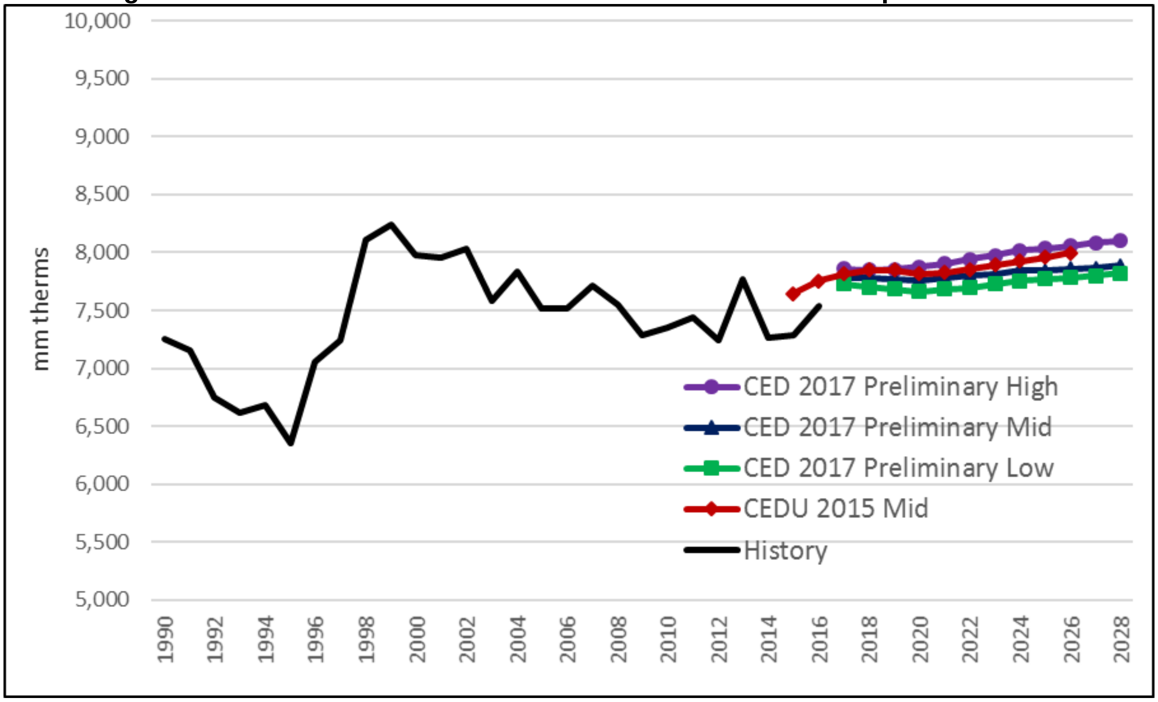
Table 17: Comparison of *CED 2017 Preliminary* and *CED 2015* Mid Case Demand Baseline Forecasts of SoCal Gas End-User Natural Gas Consumption

Natural Gas Consumption (mm therms)				
	CED 2015 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	6,806	7,252	7,252	7,252
2000	7,938	7,979	7,979	7,979
2016	7,755	7,542	7,542	7,542
2020	7,817	7,876	7,756	7,663
2025	7,957	8,033	7,844	7,772
2026	7,995	8,057	7,856	7,781
2028	--	8,098	7,885	7,819
	Average Annual Growth Rates			
1990-2000	1.55%	0.96%	0.96%	0.96%
2000-2016	-0.16%	-0.37%	-0.37%	-0.37%
2016-2020	0.20%	1.09%	0.70%	0.40%
2016-2026	0.30%	0.66%	0.41%	0.31%
2016-2028	--	0.59%	0.37%	0.30%
Actual historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2017.

Figure 23 shows the three *CED 2017 Preliminary* cases and the *CED 2015* mid demand case. Unlike PG&E, negative climate change impacts are not sufficient to drop the mid demand case below the low. Annual growth from 2016–2026 for the *CED 2017 Preliminary* forecast averages 0.66 percent, 0.41 percent, and 0.31 percent in the high, mid, and low cases, respectively, compared to 0.30 percent in the *CED 2015* mid case.

Figure 23: SoCal Gas Baseline End-User Natural Gas Consumption Demand



Source: California Energy Commission, Demand Analysis Office, 2017.

SDG&E Natural Gas Planning Area

The SDG&E natural gas planning area contains SDG&E customers plus customers of private marketers using the SDG&E natural gas distribution system.

Table 18 compares the *CED 2017 Preliminary* demand cases with the *CED 2015* mid case for SDG&E for selected years. Again, the over prediction in *CED 2015* for 2016 is evident, around 70 mm therms. In this case, however, consumption growth from 2017-2026 is slightly higher in the new mid case, as population growth is projected to be higher over this period compared to *CED 2015*.

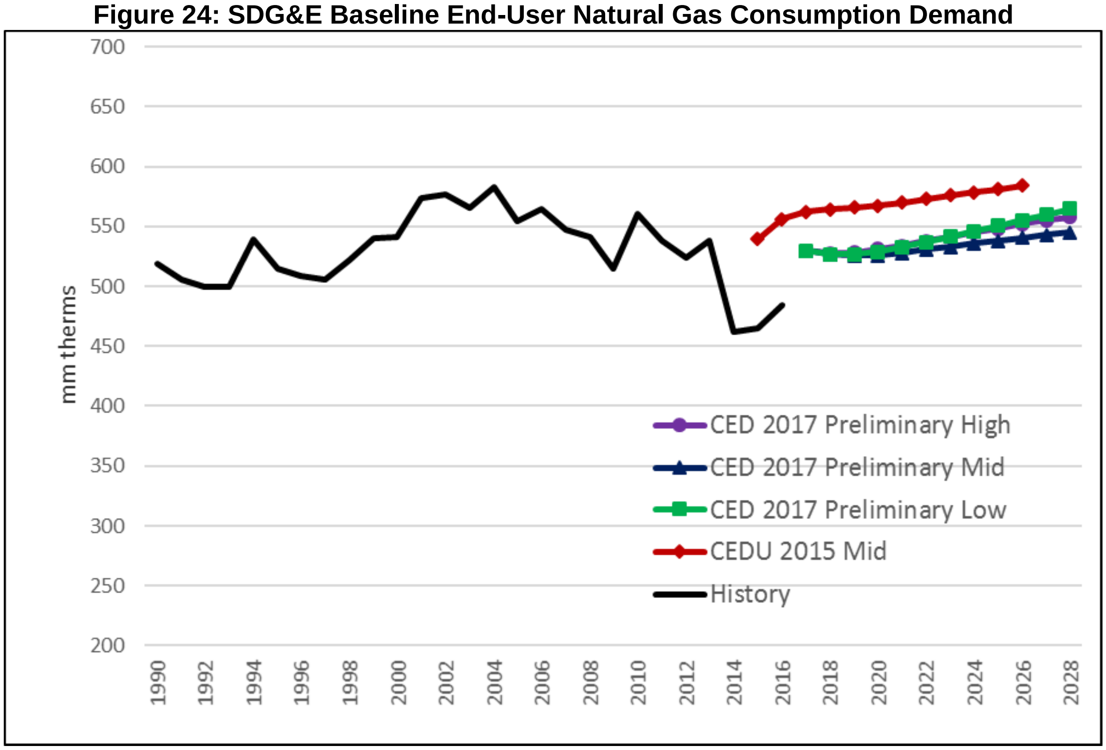
Figure 24 shows the three *CED 2017 Preliminary* cases and the *CED 2015* mid demand case. For SDG&E, climate change impacts are sufficient to drop both the mid and high demand cases below the low by the end of the forecast period. Annual growth from 2016–2026 for the *CED 2017 Preliminary* forecast averages 1.30 percent, 1.09 percent, and 1.36 percent in the high, mid, and low cases, respectively, compared to 0.49 percent in the *CED 2015* mid case. *CED 2017 Preliminary* consumption growth rates are higher from 2016–2028 than the other two planning areas because the jump in 2017 is higher in percentage terms.

Table 18: Comparison of CED 2017 Preliminary and CED 2015 Mid Case Demand Baseline Forecasts of SDG&E End-User Natural Gas Consumption

Natural Gas Consumption (mm therms)				
	CED 2015 Mid Energy Demand	*CED 2017 Preliminary* High Energy Demand	*CED 2017 Preliminary* Mid Energy Demand	*CED 2017 Preliminary* Low Energy Demand
1990	717	519	519	519
2000	565	541	541	541
2016	556	485	485	485
2020	567	531	526	529
2025	581	548	538	550
2026	584	552	540	555
2028	--	558	545	565
	Average Annual Growth Rates			
1990-2000	-2.35%	0.43%	0.43%	0.43%
2000-2016	-0.11%	-0.73%	-0.73%	-0.73%
2016-2020	0.51%	2.31%	2.06%	2.18%
2016-2026	0.49%	1.30%	1.09%	1.36%
2016-2028	--	1.17%	0.98%	1.28%
Actual historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2017.

Figure 24: SDG&E Baseline End-User Natural Gas Consumption Demand



Source: California Energy Commission, Demand Analysis Office, 2017.

LIST OF ACRONYMS

Acronym	**Definition**
BANC	Balancing Authority of Northern California
BUGL	Burbank-Glendale
Energy Commission	California Energy Commission
CARB	California Air Resources Board
California ISO	California Independent System Operator
CED	*California Energy Demand*
CED 2017 Preliminary	*California Energy Demand 2018 – 2028 Prelim Forecast*
CEDU 2016	*California Energy Demand Updated Forecast, 2017-2027*
CPUC	California Public Utilities Commission
DOF	Department of Finance
DWR	Department of Water Resources
EV	Electric vehicle
GWh	Gigawatt-hour
IEPR	*Integrated Energy Policy Report*
IID	Imperial Irrigation District
IOU	Investor-owned utility
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
MW	Megawatt
NEM	Net energy metering
NCNC	Northern California Non-California ISO
PG&E	Pacific Gas and Electric Company
POU	Publicly owned utility
PV	Photovoltaic
QFER	Quarterly Fuel and Energy Report

Acronym	**Definition**
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SMUD	Sacramento Municipal Utility District
TAC	Transmission Access Charge

APPENDIX A: Self-Generation Forecasts

Compiling Historical Distributed Generation Data

The first stage of forecasting involved processing data from a variety of distributed generation (DG) incentive programs such as:

- New Solar Homes Partnership (NSHP).[45]
- Self-Generation Incentive Program (SGIP).[46]
- CSI Thermal Program for Solar Hot Water (SHW).[47]
- POU programs.[48]
- Investor-owned utility (IOU) net energy metering (NEM) interconnection filing.[49]

In addition, power plants with a generating capacity of at least 1 MW are required to submit fuel use and generation data to the Energy Commission under the Quarterly Fuel and Energy Report (QFER) Form 1304.[50] QFER data include fuel use, generation, onsite use, and exports to the grid. These various sources of data were used to quantify DG activity in California and to build a comprehensive database to track DG activity. One concern in using incentive program data along with QFER data is the possibility of double-counting generation if the project has a capacity of at least 1 MW. This may occur as the publicly available incentive program data do not list the name of the entity receiving the DG incentive for confidentially reasons, while QFER data collect information from the plant owner. Therefore, it is not possible to determine if a project from a DG incentive program is already reporting data to the Energy Commission under QFER. For example, the SGIP has 174 completed projects that are at least 1 MW and about 82 pending projects that are 1 MW or larger. Given the small number of DG projects meeting the reporting size threshold of QFER, double-counting may not be significant but could become an issue as an increasing amount of large SGIP projects come on-line.

---

45 Program data received on June 15, 2016, from staff in the Energy Commission's Renewables Division.

46 Downloaded on June 27, 2016, from (https://energycenter.org/index.php/incentive-programs/self-generation-incentive-program/sgip-documents/sgip-documents).

47 Downloaded on August 1, 2016, from (http://www.gosolarcalifornia.org/solarwater/index.php).

48 Program data submitted by POUs on July 2016 (http://www.energy.ca.gov/sb1/pou_reports/index.html).

49 Data used to be posted at the following site (https://www.californiasolarstatistics.ca.gov/). However, in an effort to streamline posting of data from a variety of sources, the CPUC moved data to a new website (http://www.californiadgstats.ca.gov/downloads/). The data were downloaded from the site (https://www.californiasolarstatistics.ca.gov/) on June 30, 2016.

50 Data received from Energy Commission's Supply Analysis Office on August 2, 2016.

QFER accounts for the majority of onsite generation in California with the representation of large industrial cogeneration facilities. With each forecast cycle, staff continues to refine QFER data to correct for mistakes in data collection and data entry. Because QFER data are self-reported, refinements to historical data will likely continue to occur in future forecast cycles.

Projects from incentive programs were classified as either completed or uncompleted. This was accomplished by examining the current status of a project. Each program varies in how it categorizes a project. IOU NEM projects having the following the value "Interconnected" in the field "Application Status" is counted as completed projects. For the SGIP program, a project with the status "Payment Completed" or "Payment PBI in Process" is counted as completed. For the NSHP, a project that has been approved for payment is counted as a completed project. For SHW, any project having the status "Paid" or "In Payment" was counted as a completed project.

POU PV data provided installations by sector. Staff then projected when incomplete projects will be completed based on how long it has taken completed projects to move between the various application stages. The next step was to assign each project to a county and sector. For most projects, the mapping to a county is straightforward since either the county information is already provided in the data or a ZIP code is included. For nonresidential projects, when valid North American Industry Classification System (NAICS) codes are provided in the program data, the corresponding NAICS sector description was used; otherwise, a default "Commercial" sector label was assigned. Each project was then mapped to one of 19 demand forecasting climate zones based on utility and county information. These steps were used to process data from all incentive programs in varying degrees to account for program-specific information. For example, certain projects in the SGIP program have an IOU as the program administrator but are interconnected to a POU; these projects were mapped directly to forecasting zones. Finally, capacity and peak factors from DG evaluation reports and PV performance data supplied by the CPUC were used to estimate energy and peak impacts.[51], [52]

Staff then needed to make assumptions about technology degradation. PV output is assumed to degrade by 0.5 percent annually; this rate is consistent with other reports examining this issue.[53] Staff decided to not degrade output for non-PV technologies, given the uncertainty in selecting an appropriate factor and the implication of using these factors in a forecast with a 10-year horizon. This decision was based on

---

51 For SGIP program: Itron. April 2015. 2013 *SGIP Impact Evaluation*. Report available at (http://www.cpuc.ca.gov/NR/rdonlyres/AC8308C0-7905-4ED8-933E-387991841F87/0/2013_SelfGen_Impact_Rpt_201504.pdf).

52 Energy and Environmental Economics, Inc. November 2013. *California Solar Initiative 2012 Impact Evaluation*. Report is forthcoming, but staff was provided a draft copy of the report and the simulated PV production data.

53 Navigant Consulting. March 2010. *Self-Generation Incentive Program PV Performance Investigation*. Report available at (http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm). Annual degradation rate ranged from 0.4 percent to 1.3 percent.

information from a report focused on combined heat and power projects funded under the SGIP program.[54] The report found significant decline in energy production on an annual basis by technology; however, the reasons for the decline varied and ranged from improper planning during the project design phase, a lack of significant coincident thermal load (for combined heat and power applications), improper maintenance, and fuel price volatility. Also, some technologies, such as fuel cells and microturbines, were just beginning to be commercially sold in the market, and project developers did not have a full awareness of how these technologies would perform in a real-world setting across different industries. This does not mean that staff will not use degradation factors in future reports. Once better data have been collected, staff will revisit this issue. Another issue with projects funded under SGIP is the need to account for decommissioned projects. Currently, the publicly available SGIP data set does not identify if a previously funded project has been decommissioned.

Figure A-1 shows statewide energy use from PV and non-PV technologies. Historically, PV constituted a small share of total self-generation; however, PV generation begins to show a sharp increase as the CSI program started to gain momentum after 2007, and by 2015, PV accounted for more than 32 percent of total self-generation. For self-generation as a whole, the residential sector has seen tremendous growth in recent years driven largely by PV. In 2015, self-generation from the residential sector was estimated to be more than 19 percent of the statewide total in 2015.

Figure A-2 shows PV self-generation by sector from 1995 to 2015. PV adoption is concentrated generally in the residential and commercial sectors. The growth in PV adoption was initially driven by the CSI program and shows no sign of slowing down even though CSI rebates have largely expired.

Figure A-3 shows the top 20 counties with PV by sector in 2015. PV capacity is led by Southern California, with Los Angeles, San Diego, and Riverside Counties making up the top three counties in the state with PV capacity.

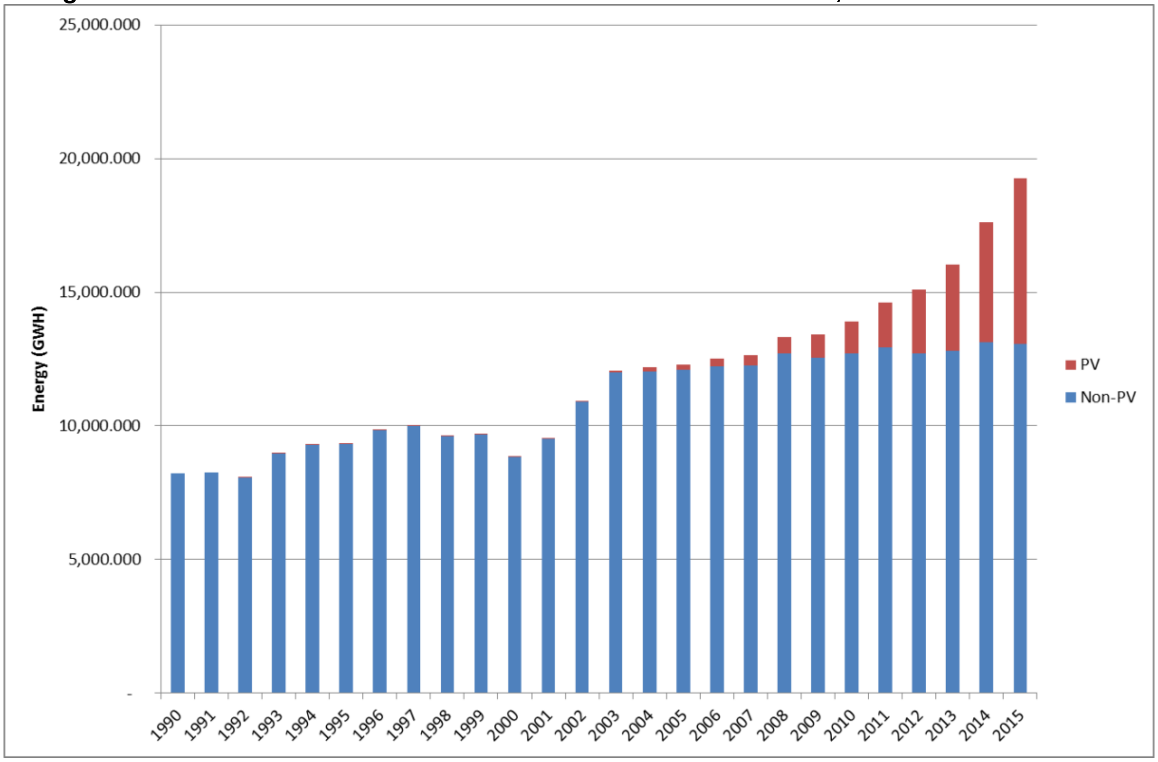
Figure A-4 breaks out self-generation by nonresidential category for the state and shows a continued overall dominance by the industrial and mining (resource extraction) sectors, although commercial adoptions are clearly trending upward in recent years.

Figure A-5 gives a breakout of self-generation by technology and shows the rapid increase in generation from PV. While renewable resources such as PV have shown a rapid increase in generation, total self-generation continues to be dominated by nonrenewable resources concentrated largely in the industrial and mining sectors.

---

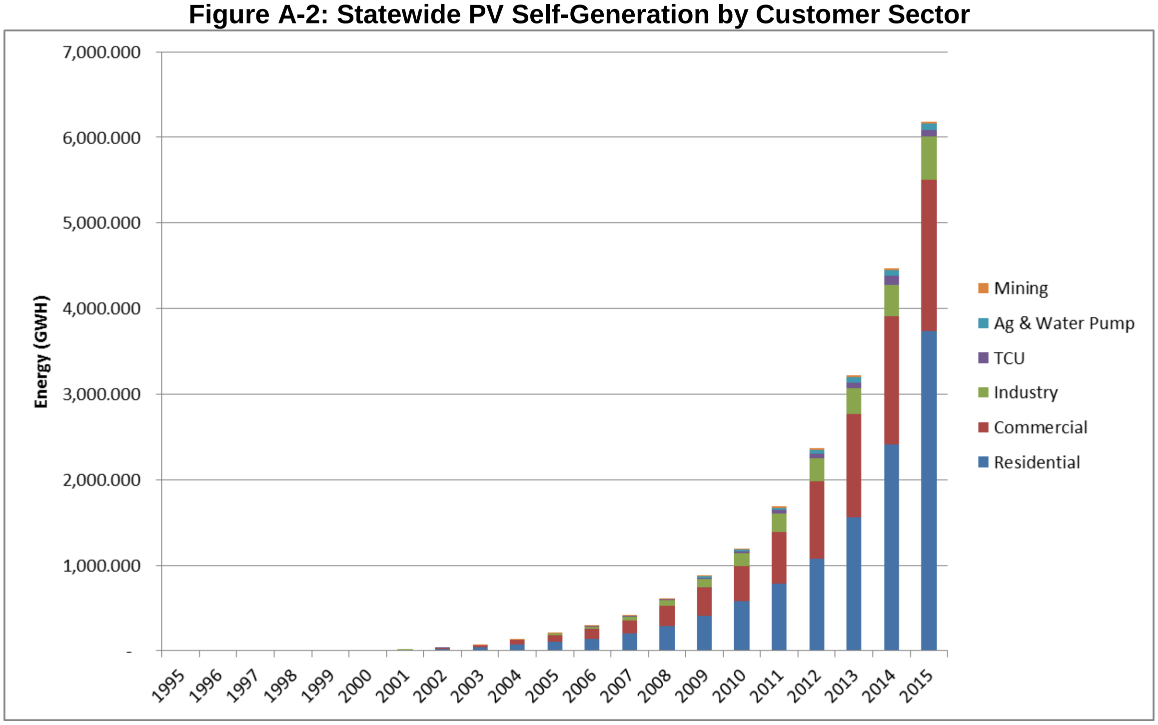
54 Navigant Consulting. April 2010. *Self-Generation Incentive Program Combined Heat and Power Performance Investigation*. Report available at (http://www.cpuc.ca.gov/NR/rdonlyres/594FEE2F-B37A-4F9D-B04A-B38A4DFBF689/0/SGIP_CHP_Performance_Investigation_FINAL_2010_04_01.pdf).

Figure A-1: Statewide Historical Distribution of Self-Generation, All Customer Sectors



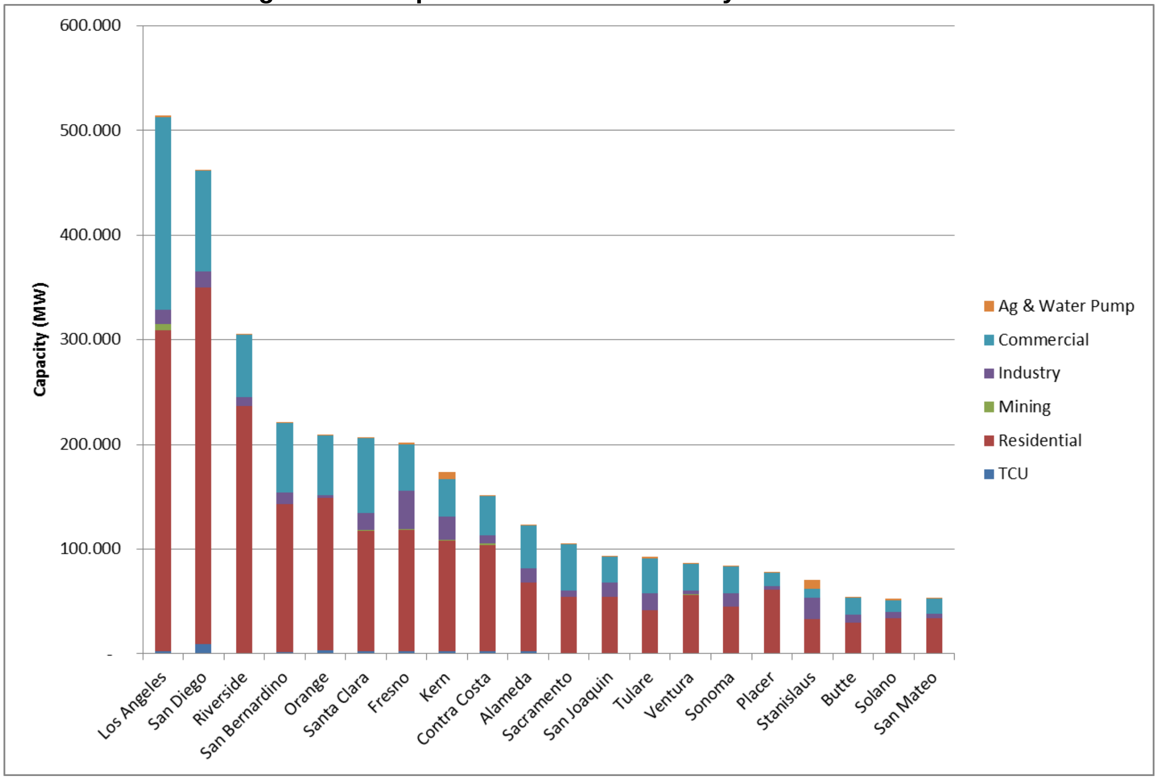
Source: California Energy Commission, Demand Analysis Office, 2017.

Figure A-2: Statewide PV Self-Generation by Customer Sector



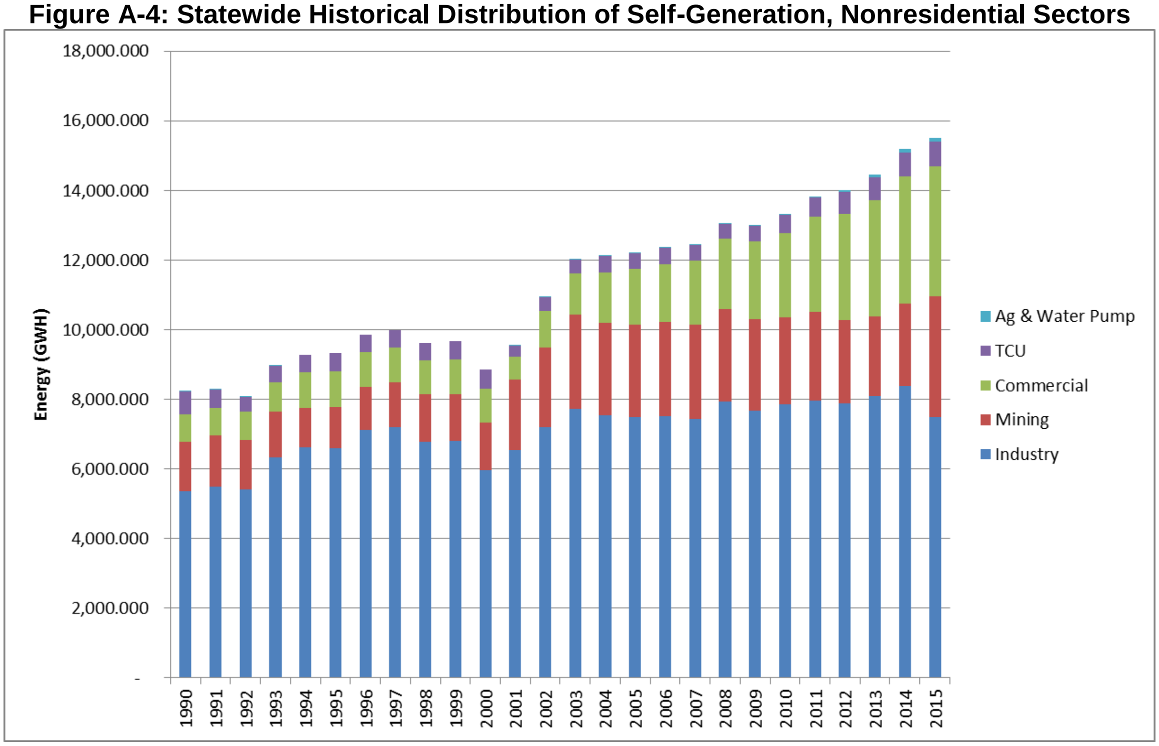
Source: California Energy Commission, Demand Analysis Office, 2017.

Figure A-3: Top 20 Counties With PV by Sector in 2014



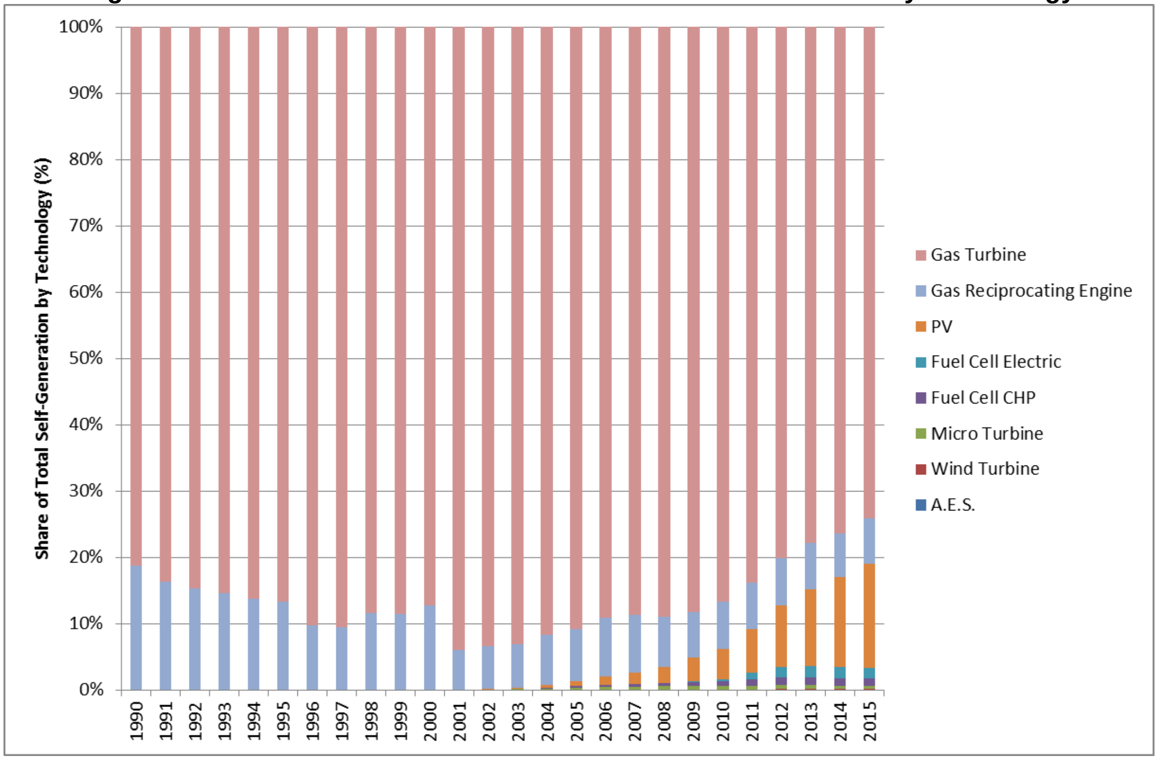
Source: California Energy Commission, Demand Analysis Office, 2017.

Figure A-4: Statewide Historical Distribution of Self-Generation, Nonresidential Sectors



Source: California Energy Commission, Demand Analysis Office, 2017.

Figure A-5: Statewide Historical Distribution of Self-Generation by Technology



Source: California Energy Commission, Demand Analysis Office, 2017.

Residential Sector Predictive Model

The residential sector self-generation model was designed to forecast PV and SHW adoption based on considering several elements such as on fuel price, system cost, and performance assumptions. The model is similar in structure to the cash flow-based DG model in the National Energy Modeling System as used by the U.S. Energy Information Administration (EIA)[55] and the *SolarDS* model developed by the National Renewable Energy Laboratory (NREL).[56]

Several changes to the residential sector model were made based on the need to account for the impact of net metering and the design of residential retail rates. Staff collected data on historical retail rates for the investor-owned utilities. Due to time constraints, staff will continue to use average sector rates as developed for *CED 2017 Preliminary* forecast for publicly owned utilities.[57] Due to limited participation from the multifamily

55 Office of Integrated Analysis and Forecasting, U.S. Energy Information Administration. May 2010. *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M067 (2010).

56 Denholm, Paul, Easan Drury, and Robert Margolis. September 2009. *The Solar Deployment System (SolarDS) Model: Documentation and Sample Results*. NREL-TP-6A2-45832.

57 Staff was able to incorporate retail rates for the Sacramento Municipal Utilities District.

segment of the residential sector, staff limited its modeling of PV adoption to single-family homes.[58]

PV cost and performance data were based on analysis performed by Energy and Environmental Economics (E3) for the CPUC.[59], [60] Historical PV price data were compiled from rebate program data and a comprehensive report from Lawrence Berkeley National Laboratory.[61] To forecast the installed cost of PV, staff adjusted the base year mean PV installed cost to be consistent with the PV price forecast developed by E3 for the mid demand case with roughly a 2 percent variation relative to the mid demand case for the high and low demand cases.

SHW cost and performance data were based on analysis conducted by ITRON in support of a CPUC proceeding examining the costs and benefits of SHW systems.[62] Adjustments were made for incentives offered by the appropriate utility to obtain the net cost.

Residential electricity and gas rates consistent with those used in *CED 2017 Preliminary* were used to calculate the value of bill savings along with historical and current retail rates used for IOUs until 2016. After 2016, staff used existing residential TOU rates for PGE and SDGE since these utilities had reached their respective NEM capacity limits, and the NEM successor tariff (NEM 2.0) decision from the CPUC required new customers to take service on a TOU rate. After 2018, staff assumed that IOU and SMUD residential customers would take service on a TOU rate. Staff used time-of-use (TOU) rates proposed as part of IOU TOU pilot projects. Further, based on other Commission analysis in support of quantifying load impacts from eventual TOU default rates for the residential sector *for CED 2017 Preliminary*, base residential load shapes used for calculating bill savings were modified to account for TOU rate impacts before accounting for the marginal impact to load from PV. Staff also incorporated a baseline credit after 2018 when calculating bill savings. The baseline credit is meant to ease the transition of residential customers from a tiered rate structure to a TOU-based rate structure. **Table A-1** shows the TOU rates by TOU period used for modeling adoption of PV for *CED 2017 Preliminary*.

---

58 The existing participation by multifamily segment generally tends to be limited to low-income units. Using adoption from this segment as a basis for generalizing adoption to the broader multifamily segment may not be appropriate.

59 PV data come from the final version of the NEM Public Tool available at (http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm).

60 Energy and Environmental Economics, Inc. November 2013. *California Solar Initiative 2012 Impact Evaluation*. Report is forthcoming, but staff was provided a draft copy of the report and the simulated PV production data.

61 Barbose, Galen and Naim Darghouth. August 2015. Tracking the Sun XIII. Report available at (https://emp.lbl.gov/publications/tracking-sun-viii-install).

62 Spreadsheet models and documents available at (https://energycenter.org/index.php/incentive-programs/solar-water-heating/swhpp-documents/cat_view/55-rebate-programs/172-csi-thermal-program/321-cpuc-documents).

Table A-1: Residential TOU Rates

		TOU Rates ($/kWh)	
Utility	Period	Summer	Winter
PGE	Peak	$ 0.34	$ 0.29
	Offpeak	$ 0.28	$ 0.27
SCE	Peak	$ 0.43	
	Midpeak		$ 0.30
	Offpeak	$ 0.23	$ 0.23
	Super_offpeak		$ 0.17
SDGE	Peak	$ 0.47	$ 0.30
	Offpeak	$ 0.28	$ 0.29
	Super_offpeak	$ 0.24	$ 0.28
SMUD	Peak	$ 0.29	$ 0.14
	Midpeak	$ 0.17	
	Offpeak	$ 0.12	$ 0.10

Source: California Energy Commission, Demand Analysis Office, 2017.

Another change for *CED 2017 Preliminary* is concerned with valuation of excess production from a renewable resource such as PV relative to customer load. The CPUC issued a decision in late 2015 instituting modest reforms to NEM.[63] Staff incorporated several elements of the adopted NEM decision such as:

- Applying non-by-passable charges on delivered energy instead of net sales.
- Applying a modest charge for interconnection.
- Assuming new NEM customers will be on a TOU rate after an IOU reaches its NEM capacity limit.[64]

These changes are important given the history of NEM, but the CPUC also deferred on additional changes until 2019. This was necessary to give additional time for implementing default residential TOU rates and to provide additional time for the CPUC's distributed resources proceeding (DRP) to develop a method and recommendation on properly valuing the locational benefits of distributed resources such as PV. The DRP is still engaged in a stakeholder-driven process to develop a method for use in valuing the locational benefits of distributed resources. Given that the findings from this proceeding have yet to be finalized, staff retained assumptions on future NEM design as used in *CED 2015 Revised*. In particular, staff assumed that excess generation will continue to be valued at the full retain rate in the low demand case. The high demand case models a hypothetical NEM successor tariff having a $3/kW capacity

63 Decision available at (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf).

64 Defined as 5 percent of noncoincident peak. Decision available at (http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/167591.PDF).

charge, a fixed $0.10/kWh compensation for any export by a customer-generator, and monthly netting.[65] The low demand case represents continuation of the existing NEM compensation scheme, while the high demand case captures the intent of utilities to reform NEM to address a perceived shift in cost from occurring by customers with PV to customers without PV. The mid demand case is similar to the high demand scenario but does not include the $3/kW capacity charge. Bill savings, including NEM calculation, also incorporates data on annual electric consumption from the Energy Commission's *2009 Residential Appliance Saturation Survey* (RASS) and residential load shape data submitted by utilities as part of the *2015 IEPR* data request.[66] The useful life for both PV and SHW was assumed to be 30 years, which is longer than the forecast period. PV surplus generation was valued at a uniform rate of $0.04/kWh in the low demand case.[67]

Projected housing counts developed for *CED 2017 Preliminary* were allocated to two space-heating types – electric and gas. The allocation is based on saturation levels from RASS. To support further geographic disaggregation of forecast results, staff also segregated residential profiles by individual electric utilities in a demand forecast zone. This effort was primarily to support disaggregation of smaller POUs that previously would have been aggregated into an IOU planning area and forecast zone.

Another change for *CED 2017 Preliminary* concerns PV system sizing. For *CED 2017 Preliminary*, staff added annual electric usage level as another variable to segment the residential sector for forecasting adoption of PV systems.[68] Staff let PV size vary such that the calculated system size was able to provide roughly 90 percent of annual electric usage. Further, staff in the Commission's Energy Efficiency Division provided typical systems sizes for new construction. For PV systems, hourly generation over the life of the system was estimated based on data provided to staff by CPUC. For SHW systems, energy saved on an annual basis was used directly to estimate bill savings.

The different discounted cost and revenue streams were then combined into a final cash flow table so that the internal rate of return (IRR) and project payback could be calculated. Revenues include incentives, avoided purchase of electricity or natural gas from the grid, tax savings on loan interest, and depreciation benefits. Costs include loan repayment, annual maintenance and operation expense, and inverter replacement cost.

---

65 Staff assumed that these changes would begin in 2018 since the mid demand case shows this is the year when the IOUs would reach their NEM capacity limit. Due to time constraints, these changes were considered only for the residential sector.

66 Load research data submitted by utilities for the *2017 IEPR* were not received in time for incorporation into *CED 2017 Preliminary*. It is expected that the updated load data will be incorporated into the revised forecast.

67 A CPUC proposed decision on surplus compensation estimated that the surplus rate for PG&E would be roughly $0.04/kWh plus an environmental adder of $0.0183/kWh. See (http://docs.cpuc.ca.gov/word_pdf/AGENDA_DECISION/136635.pdf).

68 Usage level along with type of space heating, and building type were other variables used to segment the residential sector. Data for segmenting the residential sector in this manner came from load research filings as part of the *2015 IEPR*. Updated load research data for the *2017 IEPR* has not been incorporated due to timing issues related to preparing *CED 2017 Preliminary* and IEPR filings by LSEs.

The payback calculation was based on the IRR method used in the SolarDS model. The IRR approach takes an investment perspective and takes into account the full cash flow resulting from investing in the project. The cash flow is first converted to an annuity stream before the IRR is calculated. This is necessary since outlays to handle inverter replacement may cause issues in solving for the IRR.[69] In general, the higher the IRR of an investment, the more desirable it is to undertake. Staff compared the IRR to a required hurdle rate (5 percent) to determine if the technology should be adopted. If the calculated IRR was greater than the hurdle rate, then payback was calculated; otherwise, the payback was set to 25 years. The formula for converting the calculated IRR (if above 5 percent) to payback is:

$$Payback = \frac{log(2)}{log(1 + IRR)}$$

Estimated payback then becomes an input to a market share curve. The maximum market share for a technology is a function of the cost-effectiveness of the technology, as measured by payback, and was based on a maximum market share (fraction) formula defined as:

$$MaximumMarketFraction = e^{-PaybackSensitivity*Payback}$$

Payback sensitivity was set to 0.3.[70] Another change for *CED 2017 Preliminary* was to employ a different market share curve for IOUs and SMUD residential customers. The reason for using a new market share curve was based on stakeholder comments received in *2015 IEPR* and *2016 IEPR Update*.[71, 72] In general, comments from stakeholders suggested that adopters of PV may not respond as well to payback periods as much as they would to monthly bill savings motivated in part by innovative ownership models.[73] This alternative metric for estimating the market share curve, monthly bill savings, is used by NREL as part of its new PV adoption model dGen.[74] Staff found that monthly bill savings generally improved estimated adoption of PV systems in the historical period relative to using payback period for estimating the market share curve. Further, for other utilities for which staff was using average sector rates

---

69 The IRR is defined as the rate that makes the net present value (the discounted stream of costs and benefits) of an investment equal to zero and is a nonlinear function of the cash flow stream. The annuity approach also has merit in ranking technologies with unequal lives, which is the case in the commercial sector DG model.

70 Based on an average fit of two empirically estimated market share curves by RW Beck. See R.W. Beck. *Distributed Renewable Energy Operating Impacts and Valuation Study,* January 2009. Prepared for Arizona Public Service by R.W. Beck, Inc.

71 http://www.energy.ca.gov/2015_energypolicy/documents/2015-12-17_comments.php.

72 http://www.energy.ca.gov/2016_energypolicy/documents/2016-06-23_workshop/2016-06-23_comments.php.

73 https://www.aaai.org/ocs/index.php/FSS/FSS14/paper/view/9222/9123.

74 http://www.nrel.gov/docs/fy16osti/65231.pdfhttp://www.nrel.gov/docs/fy16osti/65231.pdf.

developed for *CED 2017 Preliminary,* staff used an updated market share curve based on payback period from analysis in support of CPUC's NEM proceeding.[75]

To estimate actual penetration, maximum market share was multiplied by an estimated adoption rate, calculated using a Bass Diffusion curve, to estimate annual PV and SHW adoption. The Bass Diffusion curve is often used to model adoption of new technologies and is part of a family of technology diffusion functions characterized as having an "S" shaped curve to reflect the different stages of the adoption process.

The adoption rate is given by the following equation:

$$AdoptionRate = \frac{1 - e^{-(p+q)*t}}{1 + \left(\frac{q}{p}\right) * e^{-(p+q)*t}}$$

The terms *p* and *q* represent the impact of early and late adopters of the technology, respectively. Staff used mean values for *p* (0.03) and *q* (0.38), derived from a survey of empirical studies.[76]

Self-Generation Forecast, Nonresidential Sectors

Commercial Combined Heat and Power and Photovoltaic Forecast

CED 2017 Preliminary continues to use the predictive model developed for the *2015 IEPR* demand forecast to model adoption of CHP and PV in the commercial sector. This model uses the same basic payback framework as in the residential predictive model. Staff began by allocating energy use to different building types using the *2006 Commercial End-Use Survey* (CEUS).[77] The survey contains information on each site that participated in the survey, including:

- Site floor space.
- Site roof area.
- Electricity and natural gas use per square foot.
- Grouping variables and weights for building type, building size, and forecasting climate zone.

Building sizes were grouped into four size categories based on annual electricity use. Fuel intensities (use per square foot) were then calculated for each building type and size for electricity and natural gas.

---

75 See footnote 15.

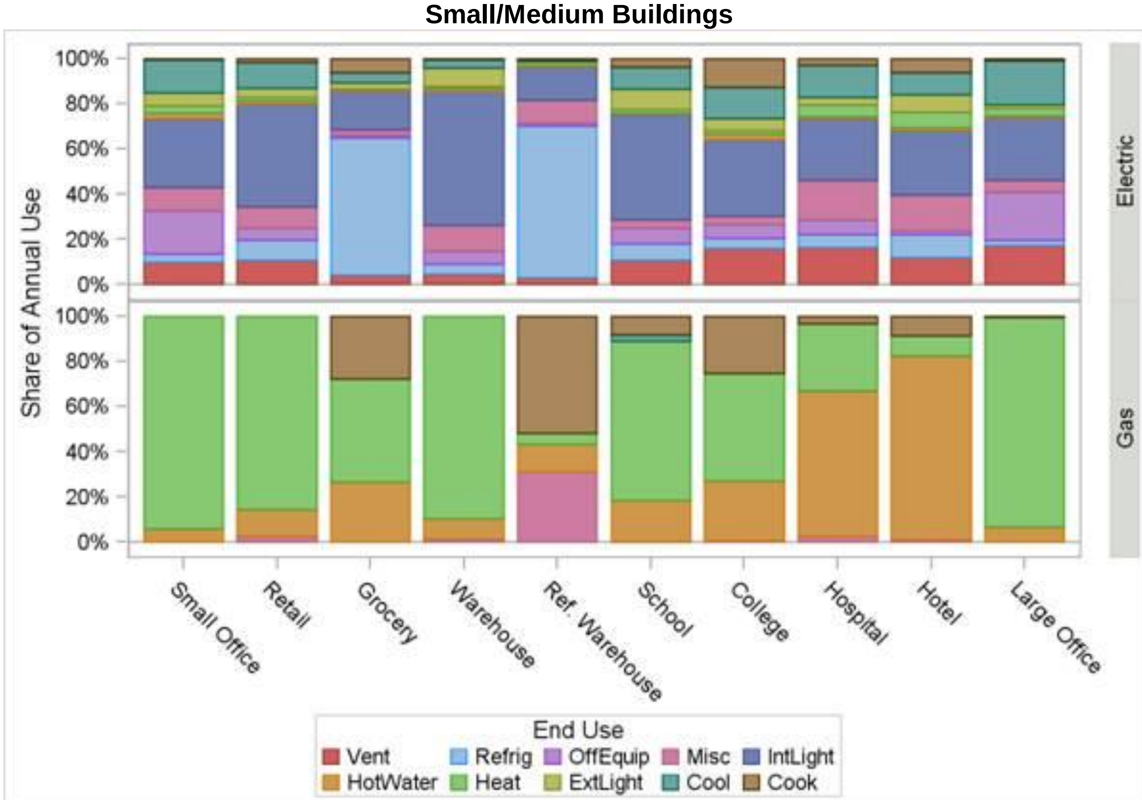
76 Meade, Nigel and Towidul Islam. 2006. "Modeling and forecasting the diffusion of innovation – A 25-year review," *International Journal of Forecasting*, Vol. 22, Issue 3.

77 Itron. March 2006. Report available at (http://www.energy.ca.gov/2006publications/CEC-400-2006-005/CEC-400-2006-005.PDF).

Next, the "DrCEUS" building energy use simulation tool, developed in conjunction with the CEUS, was used to create load shapes by fuel type and end use. DrCEUS uses the QUEST building energy use software tool as a "front end" to the considerably more complex DOE-2.2 building energy use simulation tool, which does much of the actual building energy demand simulation.

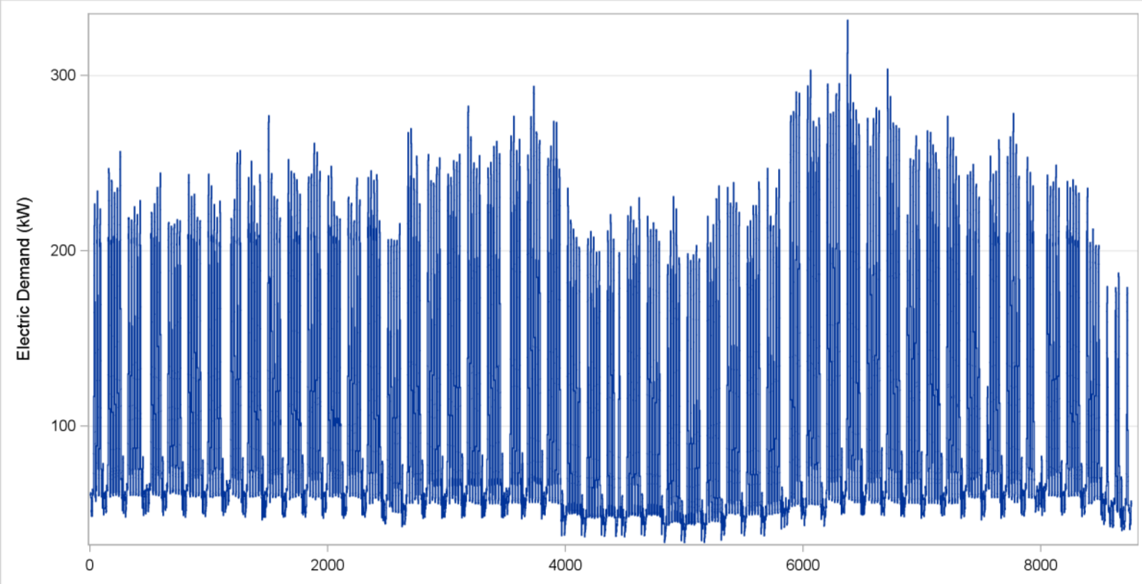
Staff grouped small and medium-size buildings together since the CEUS survey had a limited number of sample points for these building sizes. In addition, because of small sample sizes, staff grouped inland and coastal climate zones together. Four geographic profiles were created: north inland, north coastal, south inland, and south coastal. These profiles were used to create prototypical building energy use load profiles that could then be used to assess the suitability of CHP technologies in meeting onsite demand for heat and power. As examples, **Figure A-6** shows the distribution of annual consumption among end uses for electricity and natural gas for the north coastal climate zones for small and medium-size buildings, and **Figure A-7** shows hourly electricity loads for south coastal large schools.

Figure A-6: Distribution of Annual End-Use Consumption by Fuel Type – North Coastal Small/Medium Buildings



Source: California Energy Commission, Demand Analysis Office, 2017.

Figure A-7: Hourly* Electricity Demand for Large Schools, South Coastal Climate Zones



*In chronological order (8,760 annual hours).
Source: California Energy Commission, Demand Analysis Office, 2017.

Next, the commercial sector model output was benchmarked to historical electricity and gas sales data. The distribution of energy use by fuel type and end use was then applied to the CEUS site level data and expanded by the share of floor space stock represented by the site. This essentially "grows" the site level profile from the CEUS survey to match the QFER calibrated commercial model output by end use, fuel type, forecast zone, demand case, and year.

For CHP, staff assumed that waste heat will be recovered to meet the site demand for hot water and space heating and that this waste heat will displace gas used for these two purposes.[78] Based on this assumption, the power-to-heat ratio was then calculated for each building type and size category by forecast climate zone and demand case.

CHP system sizing was determined by the product of the thermal factor, which is the ratio of the power-to-heat ratio of the CHP system to the power-to-heat ratio of the application, and the average electrical demand of the building type. A thermal factor less than 1 would indicate that the site is thermally limited relative to the electric load, while a thermal factor greater than 1 would indicate that the site is electrically limited relative to the thermal load. Thermal factors greater than 1 mean that the site can export power to the grid if the CHP system is sized to meet the base load thermal demand. Thermal factors were less than 1 for most building types.

78 ICF International. February 2012. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*. Report available at (http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf).

Finally, cost and benefits were developed to derive payback. Staff applied the same set of assumptions used in a prior Energy Commission-sponsored report to characterize CHP technology operating characteristics such as heat rate, useful heat recovery, installed capital cost, and operating costs.[79] PV technology details such as installed cost and operating cost were based from the same E3 dataset used for the residential sector predictive model. Avoided retail electric and gas rates were derived from utility tariff sheets and based on estimated premise-level maximum demand. Current retail electric and gas rates were escalated based on the rates of growth for fuel prices developed for the *CED 2017 Preliminary*. In addition, CHP technologies may face additional costs such as standby and departing load charges. Details for these charges were also collected and used in the economic assessment. Staff examined details surrounding the applicability of these charges and applied them as appropriate.

The cash flow analysis and payback-based adoption modeling were performed similarly to the residential sector PV model process, described earlier.

Other Sector Self-Generation

Staff used a trend analysis for forecasting adoption of PV in the noncommercial-nonresidential sectors. *CED 2017 Preliminary* continues to forecast energy storage systems based on a trend analysis approach similar to *CED 2015 Revised*. Data on energy storage projects from the SGIP rebate program were used to forecast future adoption of energy storage. Most energy storage projects are pending through the SGIP application queue and are expected to be operational by 2017 subject to funding availability.

Statewide Modeling Results

The following figures show results prepared for *CED 2017 Preliminary* by demand case. **Figure A-8** shows the PV generation, which reaches more than 30,000 GWh in the mid demand case and nearly 35,000 GWh in the low demand case by 2028. The changes made for forecasting PV adoption in *CED 2017 Preliminary* provide higher PV adoption in all three demand scenarios relative to the mid demand scenario from *CED 2016 Updated*.

Figure A-9 shows the non-PV generation, which reaches more than 15,400 GWh by 2026 in all three cases. The rapid increase after 2015 occurs due to the need to account for pending projects moving through the SGIP program. CHP additions in the SGIP slowed because of changes in program design, which limited participation mainly in fuel cells; SGIP now provides incentives for conventional CHP technologies, and this has led to many pending projects moving through the various application stages. However, recent modifications to SGIP could limit participation for fossil-fueled CHP technologies.[80]

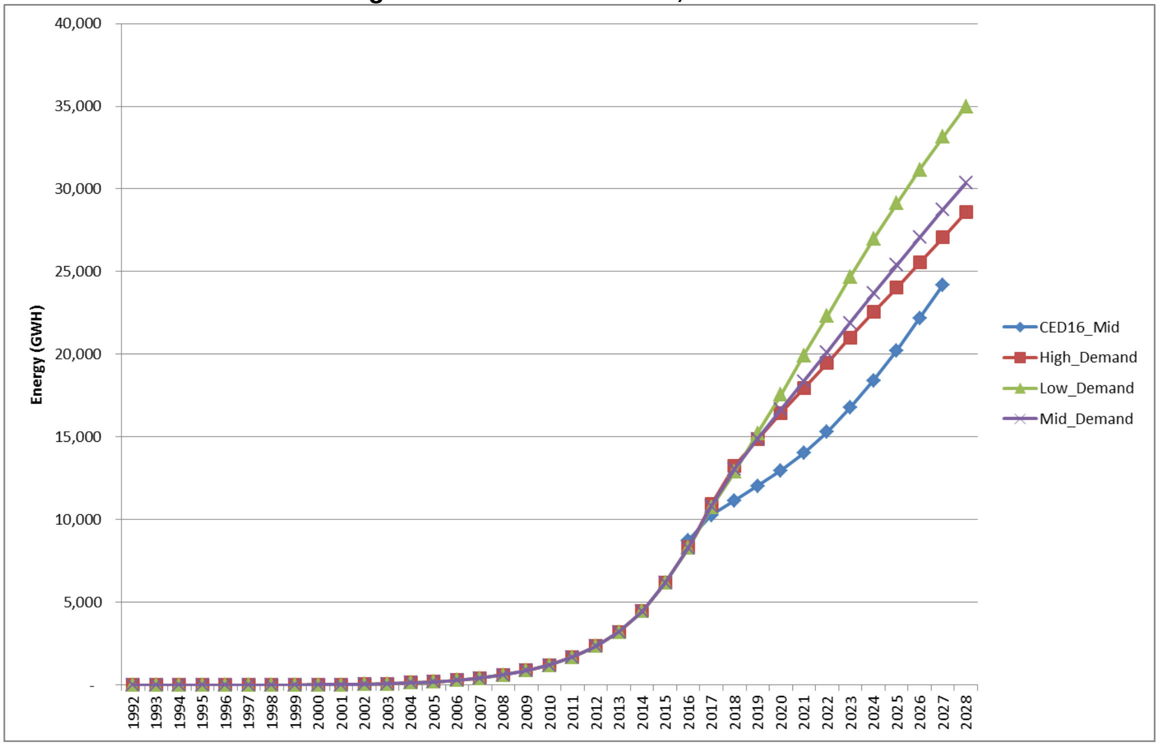
---

79 Ibid.

80 Decision available at (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M183/K843/183843620.PDF).

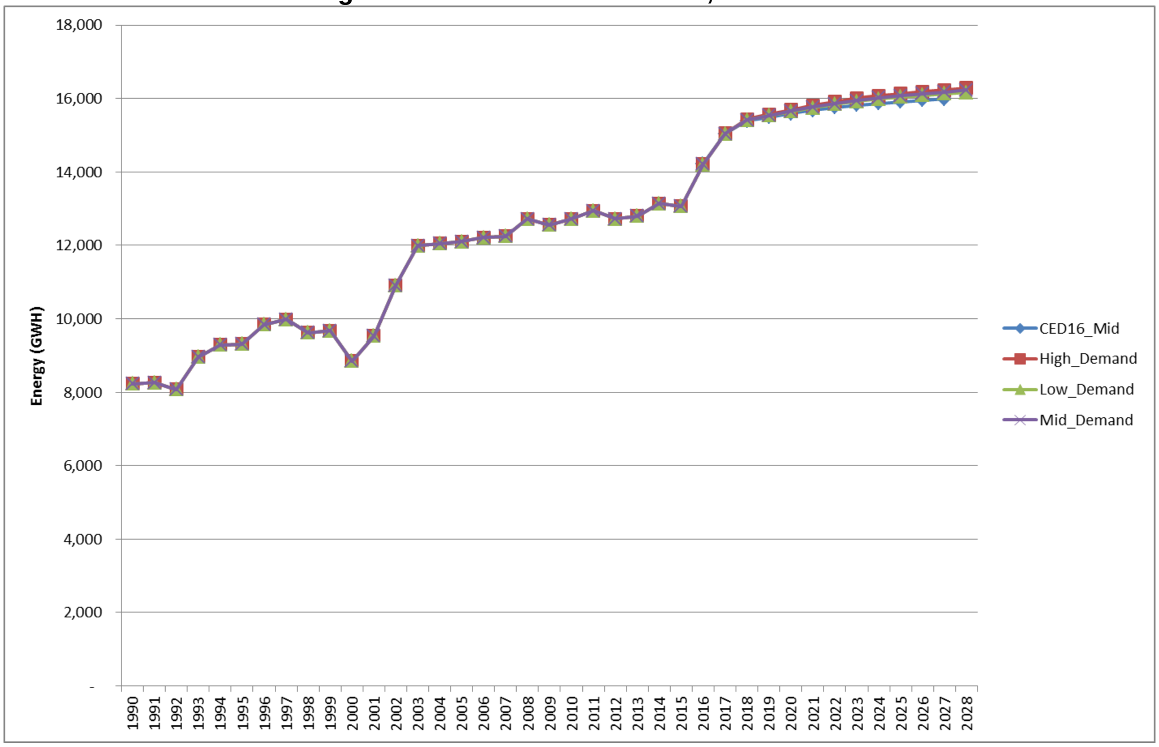
Higher commercial floor space projections in the high demand case increase adoption relative to the other cases, while higher rates in the low case have the same effect. The net result is that all three scenarios are very similar throughout the forecast period, with the high demand case yielding slightly more impact than the mid and low cases.

Figure A-8: PV Generation, Statewide



Source: California Energy Commission, Demand Analysis Office, 2017.

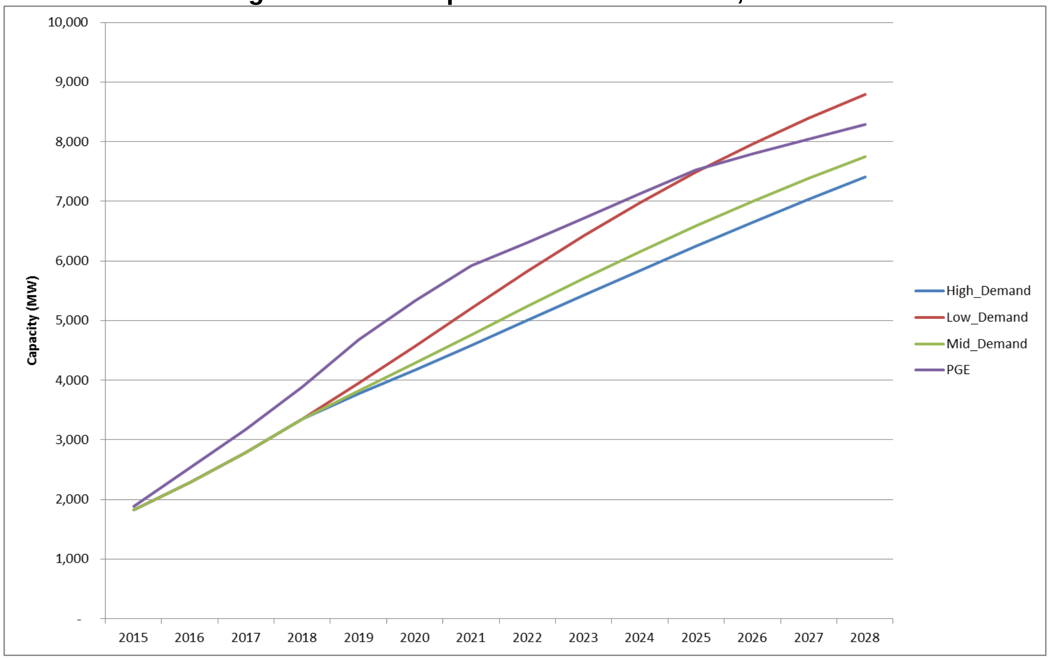
Figure A-9: Non-PV Generation, Statewide



Source: California Energy Commission, Demand Analysis Office, 2017.

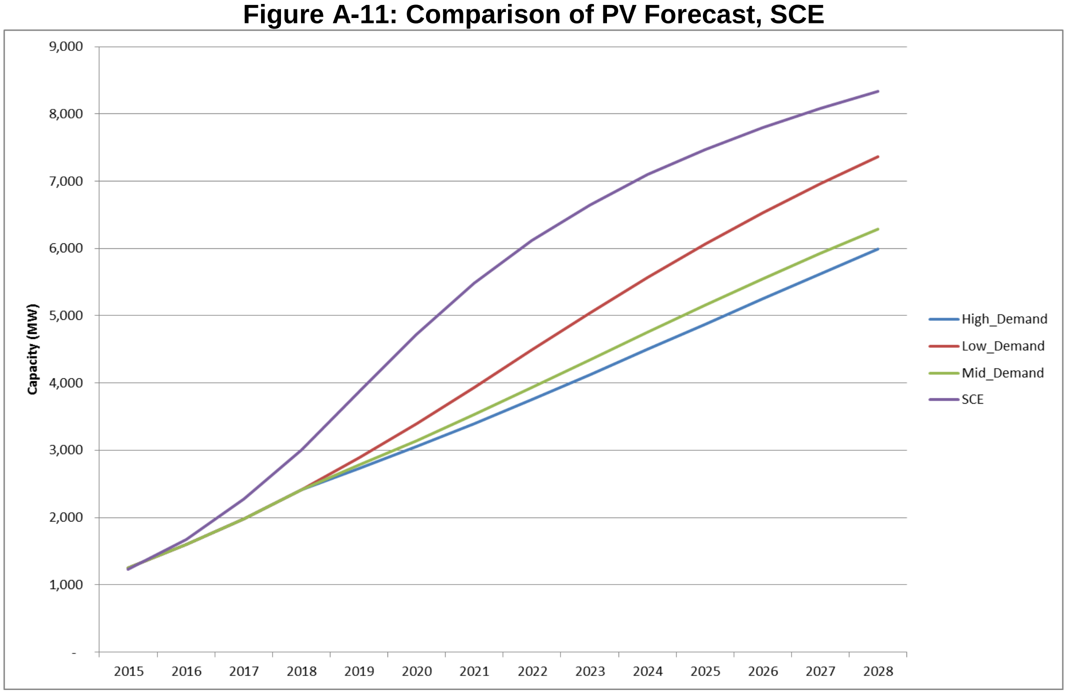
As part of the regular IEPR data collection, each utility submits a long-term demand forecast that includes impacts of distributed generation, energy efficiency, and demand response programs. **Figures A-10** through **Figure A-12** compares staff's PV forecast to the PV forecast submitted by the investor-owned utilities.

Figure A-10: Comparison of PV Forecast, PG&E



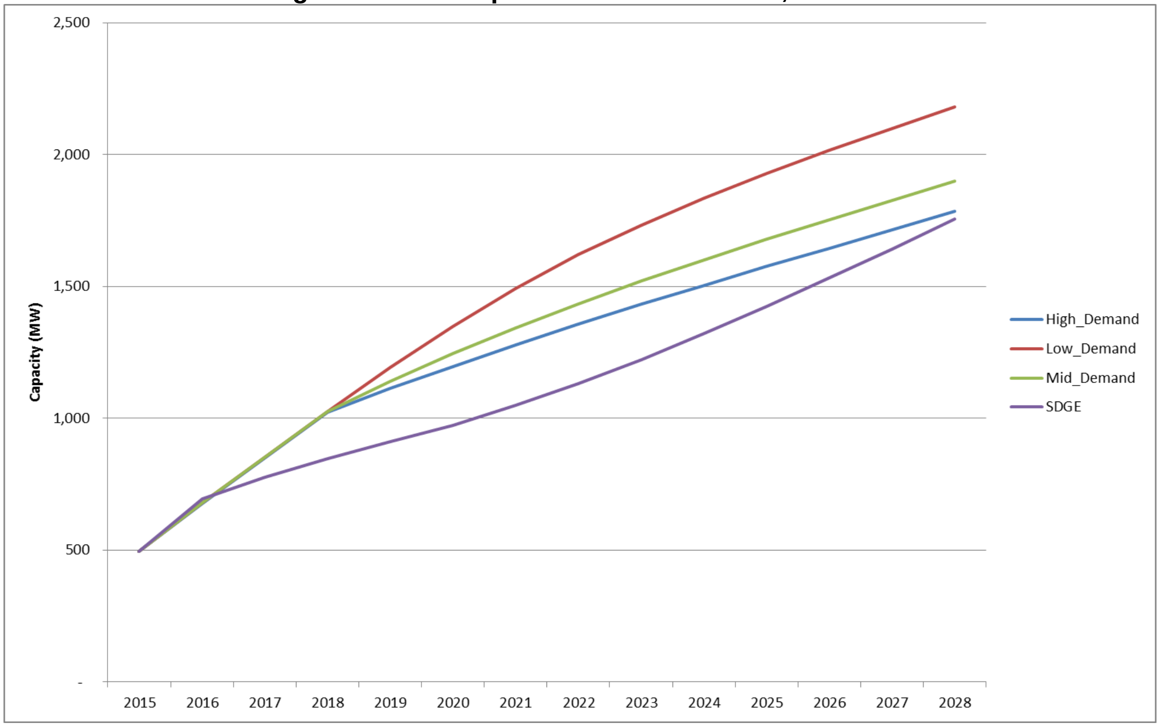
Source: California Energy Commission, Demand Analysis Office, 2017.

Figure A-11: Comparison of PV Forecast, SCE



Source: California Energy Commission, Demand Analysis Office, 2017.

Figure A-12: Comparison of PV Forecast, SDG&E



Source: California Energy Commission, Demand Analysis Office, 2017.

Staff's forecast of PV adoption is lower than PG&E's forecast over the forecast period for the mid (6.5 percent and 540 MW lower than PG&E by 2028) and high demand (10.6 percent and 880 MW lower than PG&E by 2028) scenarios, though the differences become smaller over time. Staff's forecast is higher than PG&E's forecast for the low demand (6 percent and 500 MW higher than PG&E by 2028) scenario. Based on a presentation of its forecast, staff believes that the forecast prepared by PG&E does not account for any changes to NEM and assumes compliance with zero-net-energy home (ZNEH) goals.[81] As discussed earlier, staff incorporated assumptions on reform to NEM for the mid demand and high demand scenarios but assumed no reform of NEM in the low demand scenario. Thus, it is likely that the main reason for the difference between staff's forecast and PG&E's forecast may be driven by different assumptions regarding NEM and ZNEH.

Staff's forecast of PV adoption is lower than SCE's forecast in all three demand scenarios. By 2028, staff's forecast is lower than SCE's forecast by 28 percent (2,300 MW) in the high demand case, 11.7 percent (980 MW) in the low demand case, and 25 percent (2,000 MW) in the mid demand scenario. Based on initial conversations with SCE staff, the differences may reflect modeling approaches than underlying policy assumptions, though further discussions are necessary.[82] Most notably, in its forecast,

81 http://drpwg.org/wp-content/uploads/2017/04/GSWG_Distributed_Generation-FINAL.pdf.

82 Conversation with SCE forecaster Muhammad Dayhim on 6/20/2017 at the Commission.

SCE expects additions in the first half of the forecast period to be significantly higher than any point relative to PV additions in its historical period – almost nearly doubling of additions relative to 2016, which is the last year of historical data supplied by SCE.

Staff's forecast of PV adoption is higher than SDG&E's forecast in all three demand scenarios though SDGE's forecast approaches staff's high demand scenario by 2028. By 2028, staff's forecast is higher than SDG&E's forecast by 1.6 percent (30 MW) in the high demand case, 24 percent (420 MW) in the low demand case, and 8 percent (140 MW) in the mid demand case. Based on the methodology documentation submitted by SDG&E for the *2017 IEPR*, SDG&E used the trends in PV adoption from *CED 2016 Update* to updated historical data when preparing its PV forecast for the *2017 IEPR* cycle. Thus given the methodological changes staff made in forecasting adoption of PV for *CED 2017 Preliminary*, it is reasonable to expect that staff's latest forecast would be higher than SDG&E's forecast similar to the case at the statewide level (**Figure A-8).**

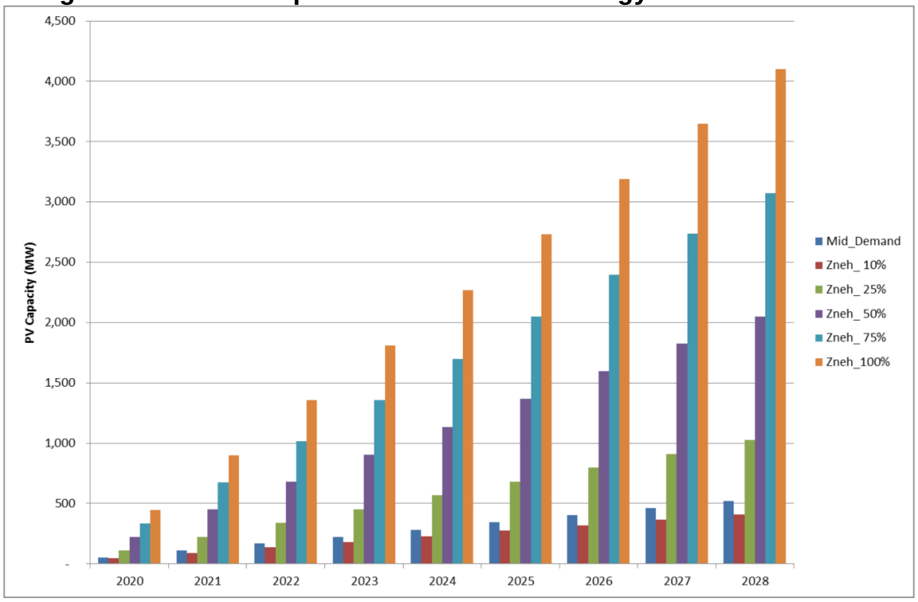
Optional Scenario

Staff also examined the relative difference in PV adoption from the mid demand case to a scenario requiring PV in new residential construction. This option models the ZNEH work underway at the Energy Commission and the CPUC.[83, 84] For this scenario, staff limited its focus to single-family homes and used PV system sizes as recommended by staff in the Commission's Energy Efficiency Division. **Figure A-13** shows cumulative PV adoption relative to the mid demand case for various levels of PV penetration in new single-family construction (cumulative incremental to 2020).

83 http://www.energy.ca.gov/2015_energypolicy/documents/2015-05-18_presentations.html.

84 http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Zero+Net+Energy+Buildings.htm.

Figure A-13: PV Adoption From Zero-Net-Energy Home Penetration



Source: California Energy Commission, Demand Analysis Office, 2017.

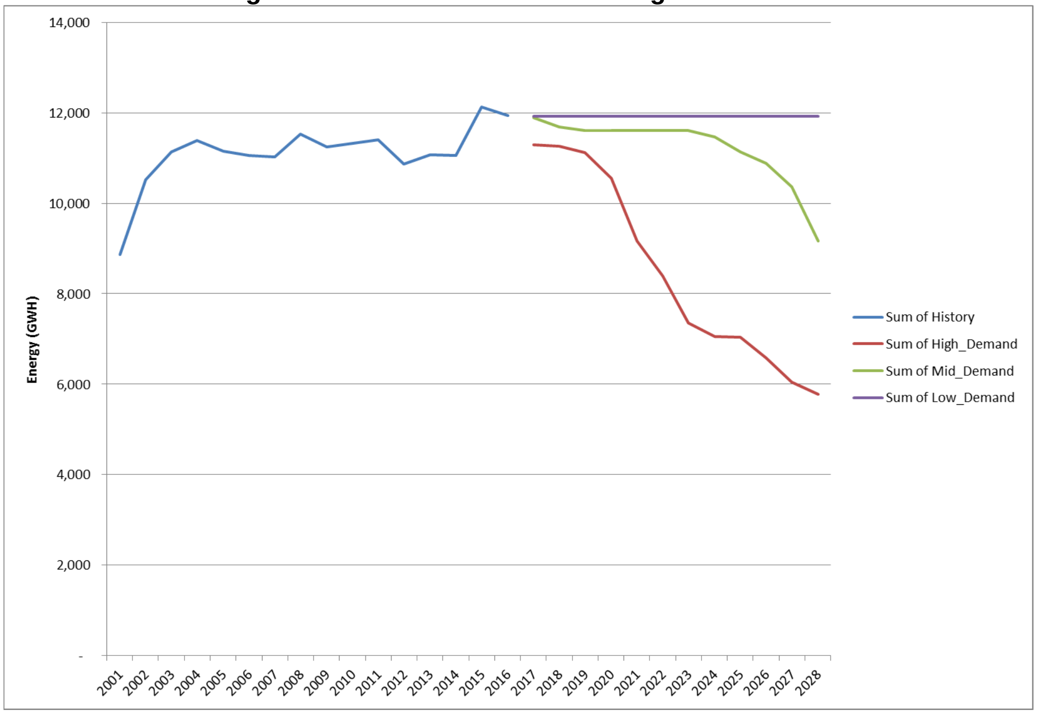
Depending on the realized compliance with any regulation requiring PV in new single-family home construction, estimates of PV adoption can vary significantly. Housing starts in this period ranged from between 118,000 to 124,000 units a year. Further, the ratcheting of energy efficiency standards toward preparation of a ZNEH standard will also affect PV system sizing, which will impact the cumulative market potential.

Another scenario staff considered for *CED 2017 Preliminary* concerns the retirement of existing large-scale CHP plants, concentrated generally in industrial and mining sectors. As described earlier, staff updates historical generation data from existing CHP plants and assumes that these plants will continue operating over the forecast period at a constant annual output level – set at the generation level in the base year. Concerns surrounding ability of existing CHP plants to obtain new contracts could result in either early retirement or curtailment in output.[85] Staff worked collaboratively with the Commission's Supply Analysis Office (SAO) to develop alternative scenarios around existing CHP, as shown in **Figure A-14**. In particular, staff assumed that in the low demand scenario, existing CHP plants would continue to operate at a constant annual output level similar to the assumption made in *CED 2017 Preliminary*. In the high demand scenario, staff assumed that existing CHP plants would operate up to the existing contract end data and then shut down. For the mid demand scenario, staff assumed that CHP plants would operate up to the existing contract end date and then

85 Both retirement and curtailment in output may require the need for host sites to find alternative sources to meet onsite thermal load – generally the use of a boiler. The result being that retail end-user natural gas sales may increase, while natural gas purchased for generation may decrease. In total, the net sales of natural gas will decrease assuming that the exported electricity is met by nonfossil units.

reduce total generation back to meet only the host's onsite demand up to the nameplate capacity of the newest generating unit until this unit is 40 years old, at which point the plant shuts down.

Figure A-14: Scenarios for Existing CHP Plants



Source: California Energy Commission, Demand Analysis Office, 2017.

Relative to the low demand scenario, total generation for onsite use could decline by 52 percent in the high demand scenario and by 23 percent in the mid demand scenario.