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California Energy Commission

COMMISSION REPORT

California Energy Demand Updated Forecast, 2017-2027

California Energy Commission

Edmund G. Brown Jr., Governor

January 2017 | CEC-200-2016-016-CMF

California Energy Commission

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ABSTRACT

The *California Energy Demand Updated Forecast 2017-2027* describes the California Energy Commission's update of the *California Energy Demand 2016-2026, Revised Electricity Forecast* developed for the *2015 Integrated Energy Policy Report*. Updated projections for electricity consumption, sales, and peak demand are provided for each of eight electricity planning areas and for the state as a whole. The forecast includes three updated 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, relatively low electricity and natural gas rates, and relatively low efficiency program and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases. Forecasts are provided at both the planning area and climate zone level (in the accompanying demand forecast forms). In addition to these baseline forecasts, updated estimates of additional achievable energy efficiency are provided for the investor-owned utility service territories.

Keywords: Electricity, demand, consumption, forecast, weather normalization, peak, natural gas, self-generation, conservation, energy efficiency, climate zone, forecast methods, additional achievable energy efficiency

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TABLE OF CONTENTS

Page

LIST OF FIGURES

LIST OF TABLES

Page

EXECUTIVE SUMMARY

Introduction

The *California Energy Demand Updated Forecast, 2017-2027* (*CEDU 2016*) report describes updated 10-year forecasts for electricity in California and for major utility planning areas within the state. *CEDU 2016* updates the forecasts provided in the *California Energy Demand 2016-2026, Revised Electricity Forecast* (*CED 2015*) by incorporating more recent economic and demographic projections and adjusting for the latest historical data available for consumption, peak demand, temperatures, and electricity rates.

CEDU 2016 includes three updated baseline cases designed to capture a reasonable range of demand outcomes over the next 10 years. The *high energy demand* case incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low committed efficiency program, self-generation, and climate change impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher committed efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases.

This report also updates the additional achievable energy efficiency (AAEE) savings forecasts developed for the investor-owned utility service territories in *CED 2015* and used for planning. The application of AAEE savings scenarios to the baseline demand forecasts results in "managed" demand forecasts of energy demand. These managed forecasts take into account expected future energy efficiency savings when forecasting total energy demand. The two primary managed forecasts combine the mid baseline demand case with two scenarios for AAEE savings: the mid and low-mid savings scenarios. AAEE savings do not differ from *CED 2015* estimates, except for a rescaling to be incremental to 2015 for energy savings and 2016 for peak demand savings. Thus, the updated managed forecasts reflect changes to the baseline forecast only. The accompanying electronic demand forecast forms provide breakouts of investor-owned utility and publicly owned utility service territory managed forecasts.

In addition to the primary demand forecast update process, *CEDU 2016* also includes an analysis of the potential effects of photovoltaics (PV) on the customer side of the meter (also known as "behind the meter") during peak demand. This scenario analysis provides an adjustment to the baseline system peak demand for the three major investor-owned utility transmission access charge areas, accounting for the expected growth in behind-the-meter PV adoption and projected hourly AAEE. The "transmission access charge" is the mechanism used to recover costs related to owning, maintaining and operating the California Integrated System Operator's electric transmission system. The scenario analysis can be used by the California ISO in its Transmission Planning Process studies to review previously approved projects or procurement of existing resource adequacy resources to maintain local reliability but should not be used in the identification of new needs triggering new transmission projects given the preliminary nature of the analysis.

Forecast Results

Table ES-1 compares the *CEDU 2016* baseline forecast for selected years with the *CED 2015* mid demand case. For statewide electricity consumption, the new forecast begins about 1 percent below *CED 2015* in 2015, reflecting less actual economic growth in California than predicted in 2015 for the early years of the forecast, particularly in the Northern Valley and Central Valley areas. While economic growth was more modest for the near-term forecast horizon, consumption in the updated mid scenario grows at a slightly higher rate through 2026 compared with the *CED 2015* mid demand scenario due to more optimistic long-term economic growth expectations. Updated statewide peak demand is lower than predicted in the *CED 2015* mid case in 2016 and grows at a similar rate from 2016-2026 in the new mid case for the same reason as consumption: more modest expectations for near-term growth but an optimistic long-term outlook.

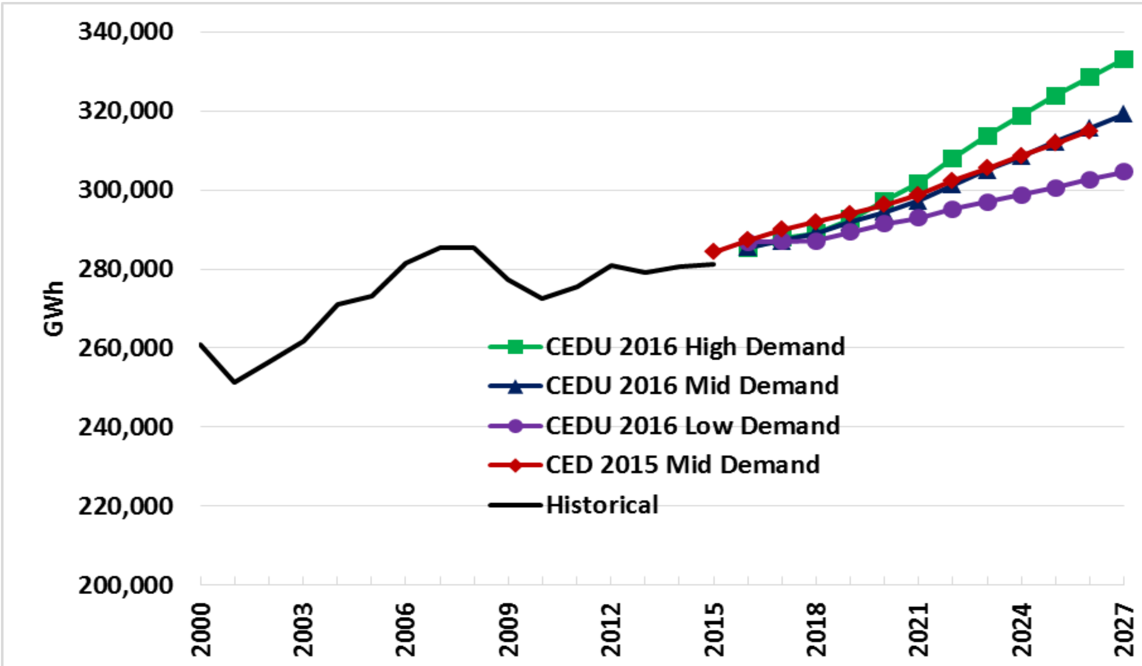
Table ES-1: Comparison of *CEDU 2016 and CED 2015* Mid Case Demand Baseline Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	227,606	227,606	227,606	227,606
2000	261,036	261,036	261,036	261,036
2015	284,343	281,334	281,334	281,334
2020	296,244	297,280	294,474	291,477
2026	314,970	328,559	315,683	302,603
2027	-	333,100	319,256	304,639
	Average Annual Growth Rates			
1990-2000	1.38%	1.38%	1.38%	1.38%
2000-2015	0.57%	0.50%	0.50%	0.50%
2015-2020	0.82%	1.11%	0.92%	0.71%
2015-2026	0.93%	1.42%	1.05%	0.66%
2015-2027	-	1.42%	1.06%	0.67%
Noncoincident Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	47,123	47,123	47,123	47,123
2000	53,529	53,529	53,529	53,529
2016*	61,219	60,543	60,543	60,543
2020	62,414	62,644	61,444	60,332
2026	64,007	67,072	63,275	58,750
2027	--	67,772	63,501	58,370
	Average Annual Growth Rates			
1990-2000	1.28%	1.28%	1.28%	1.28%
2000-2015	0.84%	0.77%	0.77%	0.77%
2016-2020	0.48%	0.86%	0.37%	-0.09%
2016-2026	0.45%	1.03%	0.44%	-0.30%
2016-2027	-	1.03%	0.43%	-0.33%
Historical values are shaded.				
*Weather normalized: *CEDU 2016* uses 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, 2016.

Figure ES-1 shows projected *CEDU 2016* electricity consumption for the three baseline cases and the *CED 2015* mid demand forecast. By 2026, consumption in the updated mid case is projected to be 0.23 percent lower than the *CED 2015* mid case. Annual growth rates from 2015-2026 for the *CEDU 2016* cases average 1.42 percent, 1.05 percent, and 0.66 percent in the high, mid, and low cases, respectively, compared to 0.93 percent in the *CED 2015* mid case. Although there is a small reduction in starting point due to more pessimistic economic growth in the near term, long-term growth in consumption remains comparable to *CED 2015* mid case.

Figure ES-1: Statewide Baseline Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2016.

Table ES-2 shows a comparison of key statewide forecast drivers for *CEDU 2016* demand cases and the *CED 2015* mid demand case. Faster growth rates for personal income and manufacturing output is countered by slower population growth and a decreasing commercial employment rate in the updated mid case compared to *CED 2015*. These counteractive effects result in similar overall projections of energy demand as with *CED 2015.*

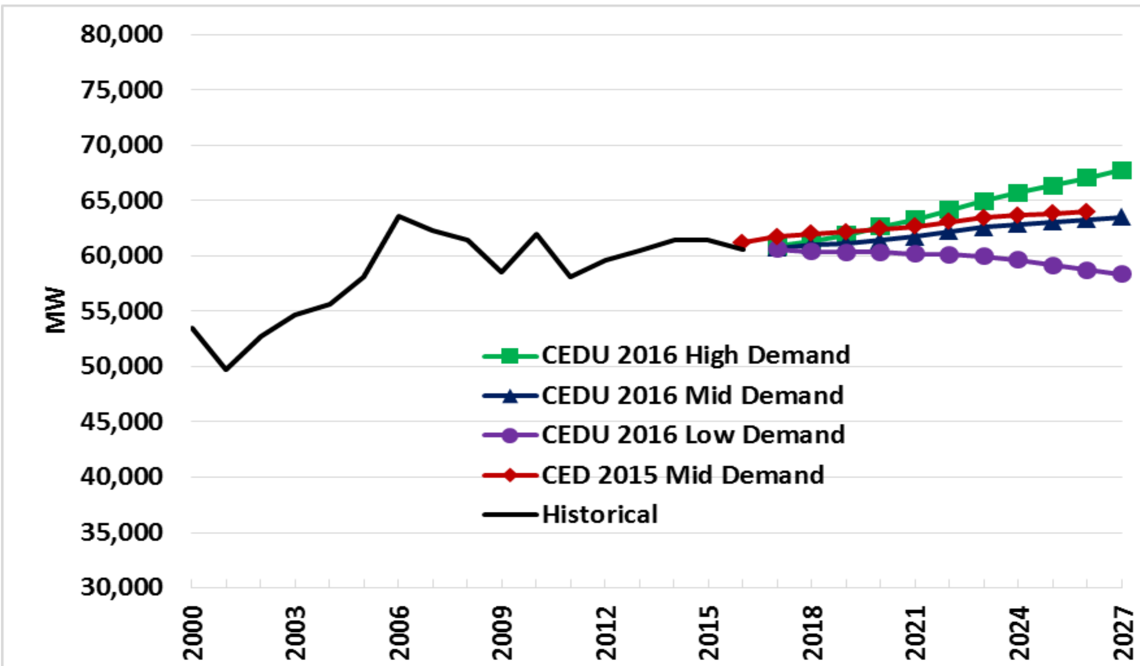
Table ES-2: Comparison of Statewide *CEDU 2016* and *CED 2015* Mid Case Economic and Demographic Drivers Using Average Annual Growth, 2015-2026

Driver	*CED 2015* Mid Energy Demand	*CEDU 2016* High Energy Demand	*CEDU 2016* Mid Energy Demand	*CEDU 2016* Low Energy Demand
Personal Income	2.88%	3.18%	2.94%	2.71%
Population	0.93%	0.88%	0.88%	0.86%
Manufacturing Output	2.38%	5.07%	2.68%	2.35%
Commercial Employment	1.19%	1.25%	1.17%	1.06%

Source: Moody's Analytics and IHS Global Insight, 2015-2016.

Figure ES-2 shows projected *CEDU 2016* noncoincident peak demand for the three baseline cases and the *CED 2015* mid demand peak forecast. By 2026, statewide peak demand in the updated mid case is projected to be 1.1 percent lower than the *CED 2015* mid case, primarily due to a lower weather-normalized starting point for 2016. Annual growth rates from 2016-2026 for the *CEDU 2016* cases average 1.03 percent, 0.44 percent, and -0.30 percent in the high, mid, and low cases, respectively, compared to 0.45 percent in the *CED 2015* mid case. As with consumption, modest growth in personal income and manufacturing output, combined with lower population growth and employment growth, results in a peak demand growth rate similar to *CED 2015*.

Figure ES-2: Statewide Baseline Annual Noncoincident Peak Demand

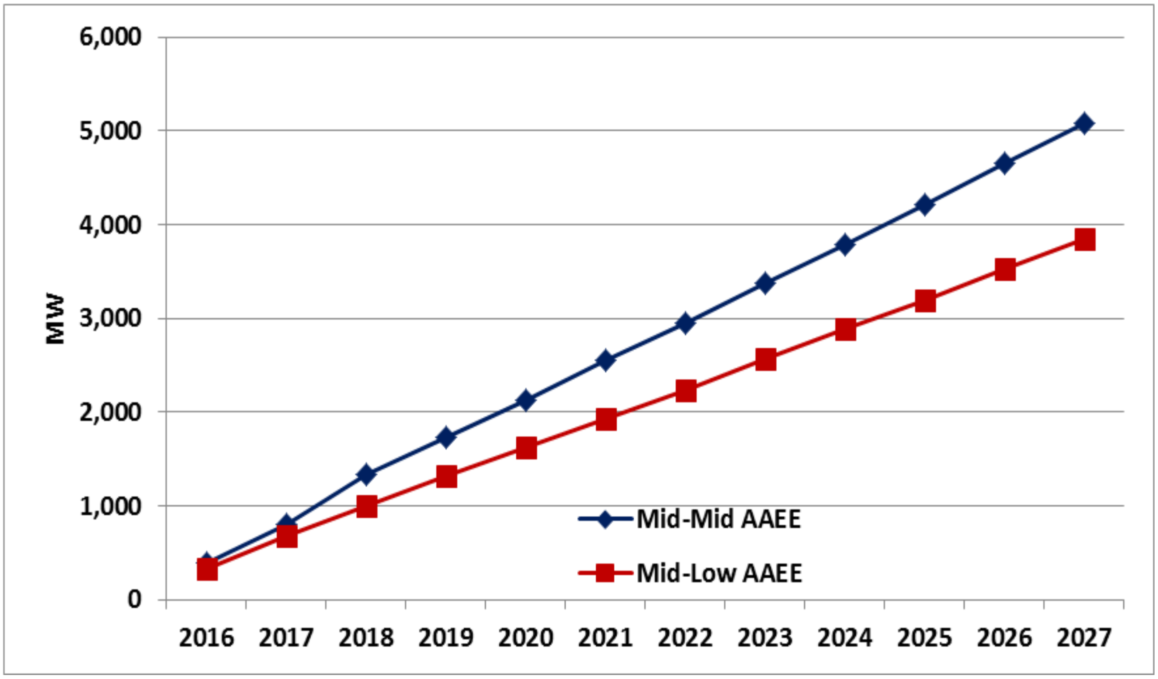


Source: California Energy Commission, Demand Analysis Office, 2016.

Updated Additional Achievable Energy Efficiency Savings Estimates

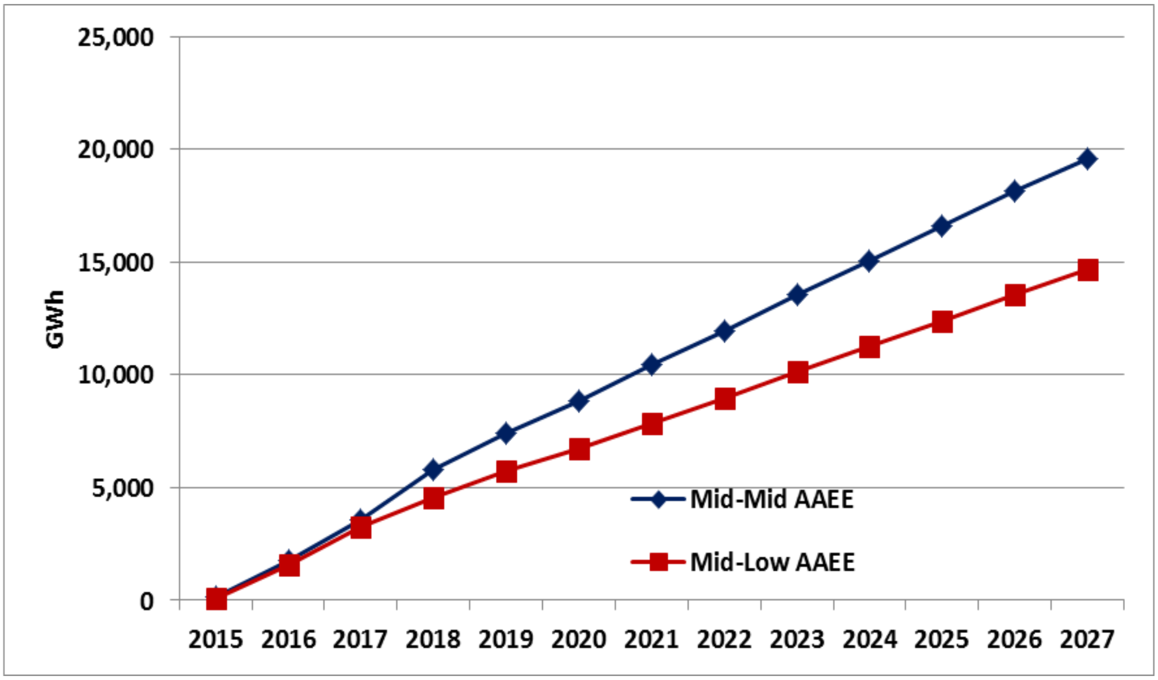
Figure ES-3 and **Figure ES-4** show updated and rescaled projected savings from AAEE for each investor-owned utility service territory and the three investor-owned utilities combined for 2015-2027 for the mid and low-mid AAEE scenarios, respectively. These savings are subtracted directly from investor-owned utility service territory sales and peak forecasts to provide updated managed forecasts. Impacts of the managed forecasts are reflected in the subregional demand forms accompanying this report (Forms 1.1c and 1.5x). Total investor-owned utility AAEE savings at peak is expected to reach 5,000 megawatts (MW) and 3,800 MW including losses by 2027 for the mid-mid AAEE and mid-low AAEE cases, respectively. Total investor-owned utility AAEE savings for energy is expected to reach 19,500 gigawatt-hours (GWh) and 14,600 GWh by 2027 for the mid-mid AAEE and mid-low AAEE cases, respectively.

Figure ES-3: IOU Total Peak AAEE Savings



*Includes estimated transmission and distribution losses.
Source: California Energy Commission, Demand Analysis Office, 2016.

Figure ES-4: IOU Total Energy AAEE Savings



Source: California Energy Commission, Demand Analysis Office, 2016.

Peak-Shift Scenario Analysis

As demand modifiers such as PV, efficiency, time-of-use pricing, and electric vehicles affect load to a growing degree, hourly load profiles may change to the extent that peak load provided by load-serving entities may occur at a different hour of the day. In particular, PV generation may shift utility peaks to a later hour as a significant part of load at traditional peak hours (late afternoon) is served by PV, with generation dropping off quickly as the evening hours approach. For *CEDU 2016*, staff developed a scenario analysis of potential peak shift and the resulting impact on peak demand served by utilities for the investor-owned utility planning (transmission access charge) areas for the managed forecast (that is, the mid baseline case combined with mid AAEE). The results of the *final adjusted managed peak* scenario analysis can be used by the California ISO in transmission planning process studies to review previously approved projects or procurement of existing resource adequacy resources to maintain local reliability but should not be used in the identification of new needs triggering new transmission projects given the preliminary nature of the analysis. More complete analyses will be developed for future *Integrated Energy Policy Report* forecasts once full hourly load forecasting models are developed.

The *CEDU 2016* scenario analysis consisted of three main components:

- Hourly load profiles for PV generation
- Hourly load profiles for AAEE savings
- Projected weather-normalized hourly end-use loads for each of 8,760 hours for each year, where end-use load is defined as utility-supplied load including line losses plus PV generation plus avoided line losses

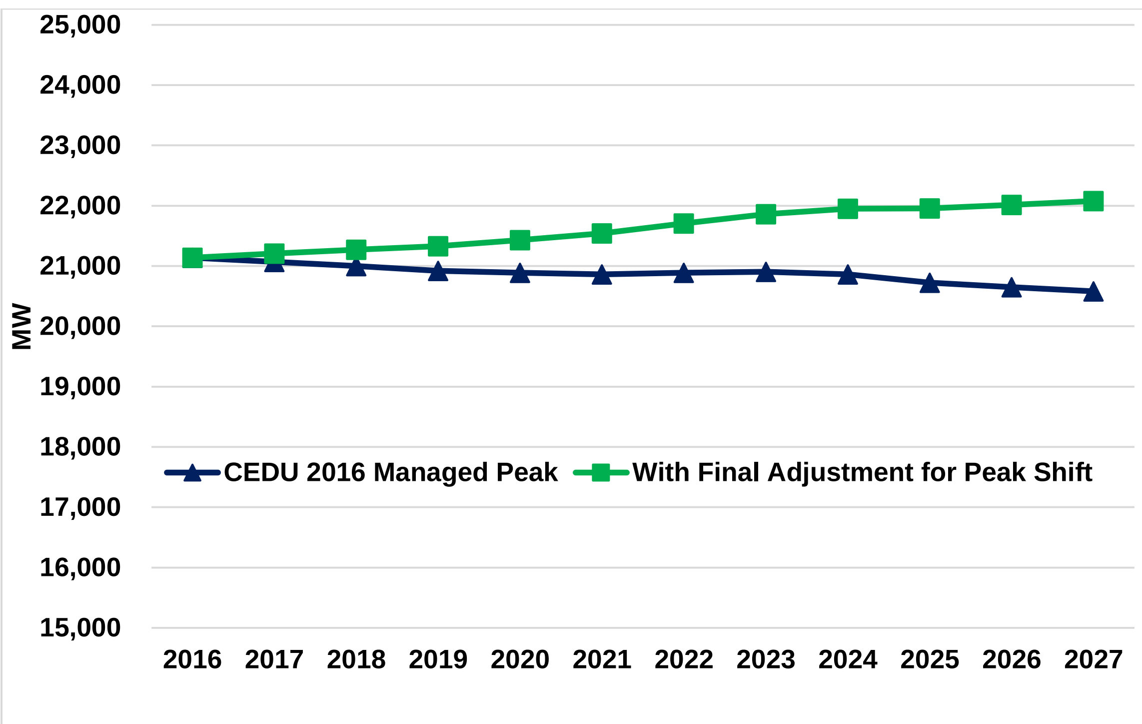
The impacts of time of use and electric vehicles were not included in the scenario analysis as estimated load shapes for these modifiers are very preliminary and require more data and study.

Once an “average weather” year was developed for hourly temperatures for each investor-owned utility, an hourly model and associated regression coefficients, along with annual end-use load forecasts from *CEDU 2016,* were applied to produce a preliminary set of 8,760 loads for each forecast year. Then, projected peak hourly end-use load for each year was calibrated to match the *CEDU 2016* forecasts for annual peak served by utilities (including line losses) plus PV generation at the conventional peak hour (plus avoided line losses).

For each year, hourly estimates of PV generation and AAEE savings (including avoided losses) were then subtracted from hourly end-use load to give estimates of loads served by utilities in each investor-owned utility planning area. The annual maximum of these hourly loads represents an adjusted peak projection for a given year that incorporates peak shift brought about by PV and AAEE, peaks that now occur at a later hour. The difference between these peaks and *CEDU 2016* projected utility-served managed peaks (that is, the mid baseline case combined with mid AAEE) for each year gives a preliminary annual peak-shift adjustment for 2016-2027. Since the *CEDU 2016* peak for 2016 is based on actual historical loads and therefore incorporates any peak shift that may have already occurred, the annual adjustments were recalculated to be incremental to 2016.

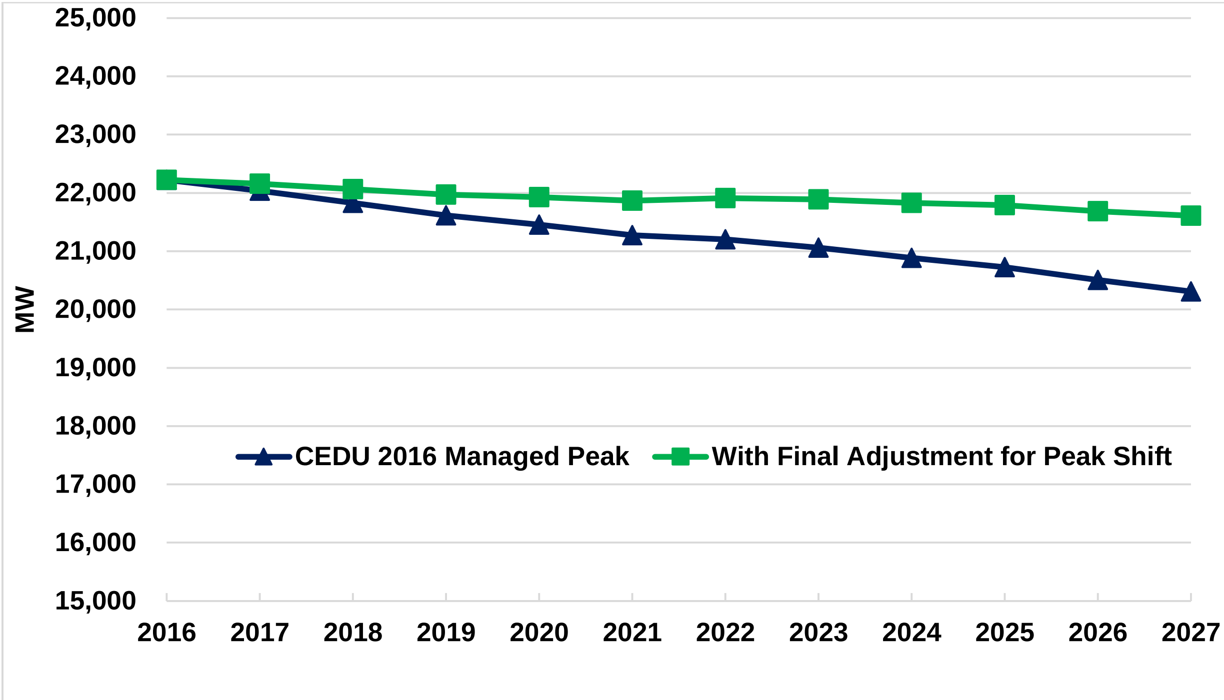
The preliminary annual peak shift adjustment includes year-to-year changes that can be abrupt but still show a clear upward trend. This reflects the particular assumptions made in developing the "average year" hourly temperatures that determine projected weather-normalized end-use loads. Other methods could certainly have been used to simulate an average weather future, which would likely have yielded a similar upward trend but different year-to-year changes in peak-shift adjustments. Therefore, staff believes that any peak-shift adjustment for years for the scenario should be applied based on the upward trend, as calculated using a linear regression with estimated peak-shift adjustments specified as a function of time. The resulting trended adjustments are shown in **Figure ES-5** for Pacific Gas and Electric, **Figure ES-6** for Southern California Edison, and **Figure ES-7** for San Diego Gas & Electric, referred to as *final* adjustments for this scenario.

Figure ES-5: *CEDU 2016* Managed Peak Forecast and Managed Forecast with Final Adjustment for Peak Shift, PG&E Planning Area



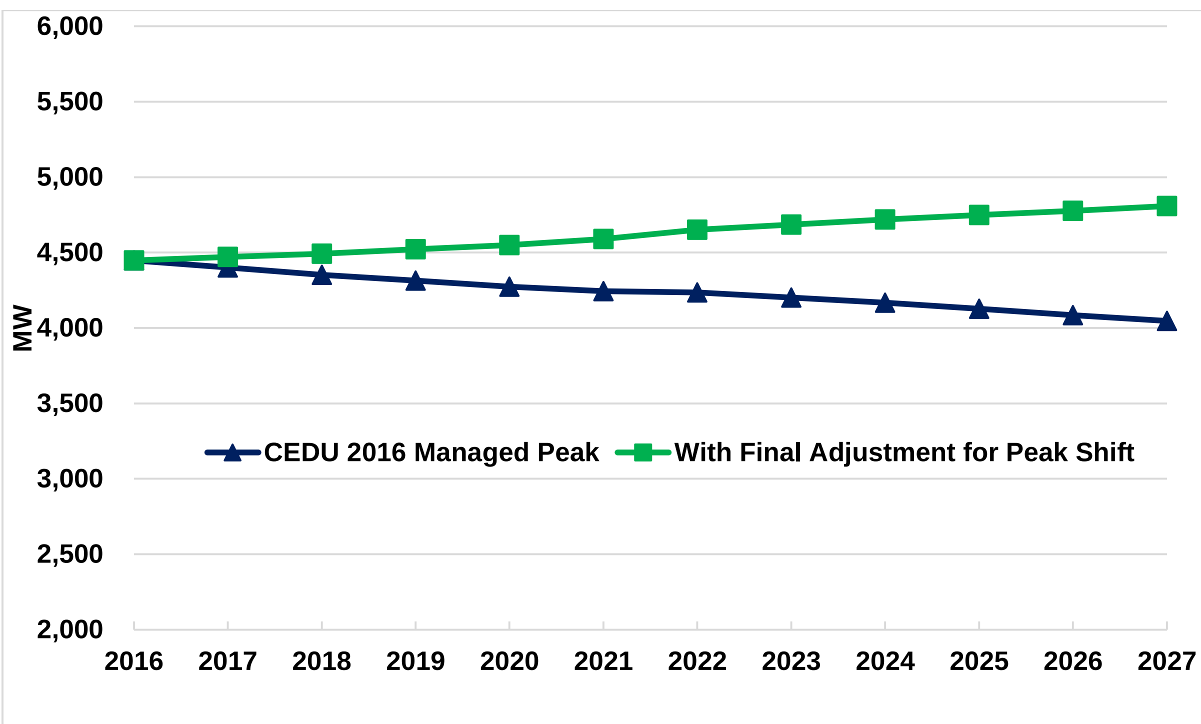
Source: Demand Analysis Office, California Energy Commission, 2016

Figure ES-6: *CEDU 2016* Managed Peak Forecast and Managed Forecast With Final Adjustment for Peak Shift, SCE Planning Area



Source: Demand Analysis Office, California Energy Commission, 2016

Figure ES-7: *CEDU 2016* Managed Peak Forecast and Managed Forecast with Final Adjustment for Peak Shift, SDG&E Planning Area



Source: Demand Analysis Office, California Energy Commission, 2016

CHAPTER 1: Statewide Baseline Forecast Results and Forecast Method

Introduction

This report presents updated forecasts of electricity consumption and peak demand for California and for each major utility planning area within the state for 2017–2027. The *California Energy Demand Updated Forecast, 2017-2027* (*CEDU 2016*) updates the forecasts provided in the *California Energy Demand 2016–2026, Revised Electricity Forecast*[1] (*CED 2015*) by incorporating more recent economic and demographic projections and adjusting for the latest historical data available for consumption, peak demand, temperatures, and electricity rates.

The California Energy Commission provides full forecasts for electricity and natural gas demand every two years as part of the *Integrated Energy Policy Report* (*IEPR*) process. The forecasts are used in various proceedings, including the California Public Utilities Commission's (CPUC) Long-Term Procurement Planning (LTPP) process and the California Independent System Operator's (California ISO) Transmission Planning Process (TPP). In addition, the Energy Commission provides annual year-ahead peak demand forecasts for the resource adequacy process in coordination with the California ISO and the CPUC.

The Energy Commission's full demand forecast is done biennially, in odd-numbered years. Recognizing the process alignment needs and schedules of the CPUC and California ISO planning studies, the Energy Commission provides an update to the full *IEPR* forecast in even-numbered years. The update consists of updating economic and demographic drivers used in the previous full *IEPR* forecast with the most current projections. Furthermore, the update adds one more year of historical electricity consumption and peak demand data, and self-generation technology adoptions and pending adoptions, which are used to recalibrate the forecast to the last historical year of data. Typically, other factors that affect the forecast, such as the results of energy efficiency programs and projected rates, are not updated. Instead, energy efficiency program savings are simply extrapolated one additional year, and rate projections are only updated for the last historical year of data, maintaining the previously forecasted growth rates.

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1 Kavalec, Chris, Nick Fugate, Cary Garcia, and Asish Gautam. 2016. *California Energy Demand 2016-2026, Revised Electricity Forecast.* California Energy Commission. Publication Number: CEC-200-2016-001-V1 Available at http://www.energy.ca.gov/2015_energypolicy/documents/#adoptedforecast.

In the current form, the *IEPR* forecast consists of two parts: a baseline forecast, which includes energy efficiency savings from initiatives already in place or approved, and a forecast of future energy efficiency savings, referred to as *additional achievable energy efficiency* (AAEE) *savings*. Combinations of the two parts yield a “managed” forecast for resource planning.

As in previous full forecasts, *CEDU 2016* includes three baseline cases: 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, relatively low electricity and natural gas rates, and relatively low efficiency program and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases. Details on input assumptions for these scenarios are provided later in this chapter.

This report also provides updated AAEE savings estimates for managed forecasts, a product of combining baseline scenarios with AAEE scenarios. Beginning with the *2013 IEPR* process, the three agencies agreed to use two managed forecasts, combining 1) the mid baseline forecast with the mid AAEE scenario and 2) the mid baseline forecast with the low-mid AAEE scenario. The first combination was used for systemwide resource planning, while the second offered a more conservative alternative for use in more localized analyses. Updated results are provided for the two AAEE scenarios. *CEDU 2016* uses the same AAEE estimates as *CED 2015*, including an additional year of savings for 2027. The savings numbers are modified to be incremental to the last historical year.[2]

In addition to the typical demand forecast update process, *CEDU 2016* also analyzes the potential effects of behind-the-meter photovoltaics (PV) on the peak demand timing and magnitude. This scenario analysis adjusts the magnitude and the timing of the managed system peak demand for the three major investor-owned utility (IOU) transmission access charge (TAC) areas, accounting for the expected growth in behind-the-meter PV adoption and projected hourly AAEE. More detail on this analysis is provided later in this report.

During the development of *CEDU 2016,* Demand Analysis Office staff hosted several Demand Analysis Working Group meetings, along with an *IEPR* workshop on December 8, 2016, to receive input from utilities, CPUC, California ISO, and other stakeholders on the preliminary demand forecast update results, the weather-normalized peak demand estimates, and the evaluation of the effect of behind-the-meter PV on peak demand

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2 Any impacts from AAEE in the last historical year (2015 for consumption and 2016 for peak demand) would be captured in actual recorded consumption or peak demand for this year. Thus, AAEE impacts need to be measured as incremental to the last historical year.

timing and magnitude. Comments and suggestions from stakeholders on these topics were incorporated into this report.

The report is structured as follows. Chapter 1 provides forecast results at the statewide level, discusses the method used to generate the updated forecast, and describes the key inputs, comparing the inputs to those used in *CED 2015*. Chapter 2 provides updated baseline forecasts and inputs for the five major utility planning areas, and Chapter 3 updates AAEE savings estimates. Chapter 4 provides an overview of the peak shift scenario analysis and recommendations for applying the results.

Statewide Results

Table 1 compares the *CEDU 2016* baseline forecast for selected years with the *CED 2015* mid demand case.[3] For statewide electricity consumption, the new forecast begins about 1 percent below *CED 2015* in 2015, reflecting less actual economic growth in California than predicted early in 2015 for the early years of the forecast, particularly in the Northern and Central Valleys. While economic growth was more modest for the near-term forecast horizon, consumption in the updated mid scenario grows at a slightly higher rate through 2026 as compared with the *CED 2015* mid demand scenario due to more optimistic long-term economic growth expectations. Updated statewide noncoincident[4] weather-normalized[5] peak demand is around 1 percent lower than predicted in the *CED 2015* mid case in 2016 and grows at a slightly higher rate from 2016-2026 in the new mid case for the same reason as consumption—more modest expectations for near-term growth but an optimistic long-term outlook.

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3 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.

4 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.

5 Peak demand is weather-normalized in 2016 to provide the proper benchmark for comparison to future peak demand, which assumes either average (normalized) weather or hotter conditions due to climate change. High and mid energy demand cases include climate change temperature impacts, and the low-scenario assumes no effects due to climate change. See *CED 2015* for more detailed discussion of the climate change scenarios.

Table 1: Comparison of *CEDU 2016* and *CED 2015* Mid Case Demand Baseline Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	227,606	227,606	227,606	227,606
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1990-2000	1.38%	1.38%	1.38%	1.38%
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Noncoincident Peak (MW)				
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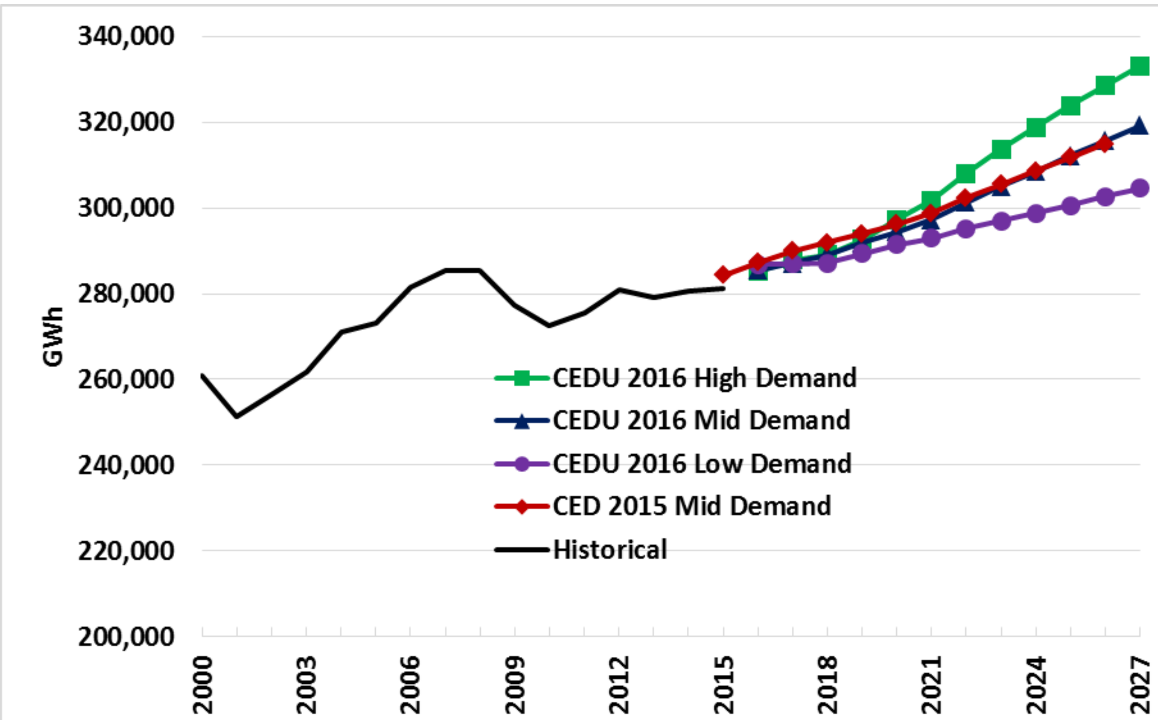
2016-2026	0.45%	1.03%	0.44%	-0.30%
2016-2027	-	1.03%	0.43%	-0.33%
Historical values are shaded.				
*Weather normalized: *CEDU 2016* uses a weather-normalized peak value derived from the actual 2016 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2016.

Figure 1 shows projected *CEDU 2016* electricity consumption for the three baseline cases and the *CED 2015* mid demand forecast. By 2026, consumption in the updated mid case is projected to be 0.23 percent lower than the *CED 2015* mid case. Annual growth rates from 2015-2026 for the *CEDU 2016* cases average 1.42 percent, 1.05 percent, and 0.66 percent in the high, mid, and low cases, respectively, compared to 0.93 percent in the *CED 2015* mid case. Although there is a small reduction in starting point due to more pessimistic economic growth in the near term, long-term growth in consumption remains comparable to *CED 2015* mid case.

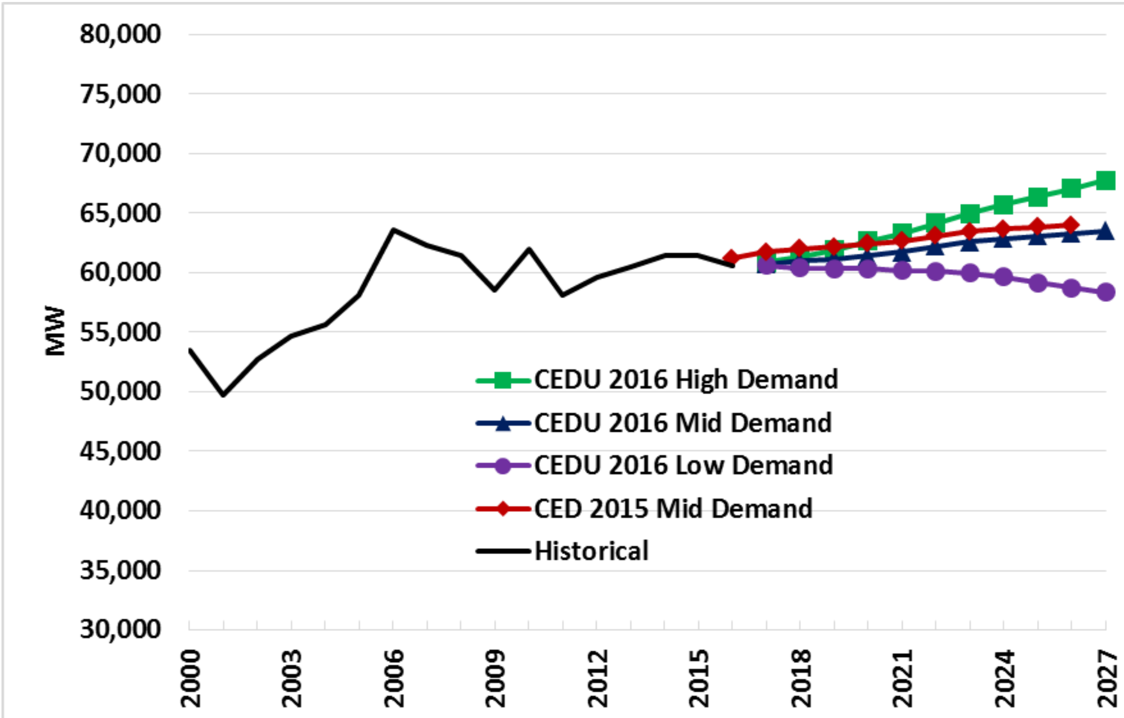
Figure 1: Statewide Baseline Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2016.

Figure 2 shows projected *CEDU 2016* noncoincident peak demand for the three baseline cases and the *CED 2015* mid demand peak forecast. By 2026, statewide peak demand in the updated mid case is projected to be 1.1 percent lower than the *CED 2015* mid case. Annual growth rates from 2016-2026 for the *CEDU 2016* cases average 1.03 percent, 0.44 percent, and -0.30 percent in the high, mid, and low cases, respectively, compared to 0.45 percent in the *CED 2015* mid case. Comparable growth in personal income and residential consumption results in similar growth of non-coincident net peak demand in the updated mid demand case compared to *CED 2015*.

Figure 2: Statewide Baseline Annual Noncoincident Peak Demand



Source: California Energy Commission, Demand Analysis Office, 2016.

Table 2 compares projected baseline annual electricity consumption in each *CEDU 2016* scenario for the three major economic sectors, residential, commercial, and industrial (a combination of manufacturing, construction, and resource extraction industries), with the *CED 2015* mid demand case. Residential and commercial consumption in the updated mid demand case grows at similar rates from 2016-2026 compared to *CED 2015* mainly due to comparable projected growth in personal income and commercial employment. Residential consumption in the mid case begins in 2015 with a historical measurement about 1 percent lower than predicted in *CED 2015,* due to lower economic growth than was expected in that sector. On the other hand, historical commercial and industrial mid case consumption began higher in 2015 than projected in *CED 2015*, exceeding previous expectations. Moreover, growth in industrial consumption is growing at a positive rate in the updated mid case compared to the negative rate predicted in *CED 2015*, the result of more optimistic projections for manufacturing output.

Table 2: Baseline Electricity Consumption by Sector

Residential Consumption (GWh)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	90,288	89,192	89,192	89,192
2018	92,767	89,459	90,242	90,485
2020	94,820	92,810	92,985	92,684
2027	--	110,813	107,993	100,693
Average Annual Growth, Residential Sector				
2015-2020	0.98%	0.80%	0.84%	0.77%
2015-2026	1.45%	1.78%	1.55%	0.99%
2015-2027	--	1.83%	1.61%	1.02%
Commercial Consumption (GWh)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	106,362	107,148	107,148	107,148
2018	110,437	111,074	110,274	109,374
2020	112,533	114,120	112,718	111,768
2027	--	125,706	120,272	117,229
Average Annual Growth, Commercial Sector				
2015-2020	1.13%	1.27%	1.02%	0.85%
2015-2026	1.01%	1.37%	0.99%	0.77%
2015-2027	--	1.34%	0.97%	0.75%
Industrial Consumption (GWh)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	48,955	49,590	49,590	49,590
2018	49,096	50,177	49,973	49,131
2020	48,735	51,325	49,725	48,249
2027	--	55,442	50,009	46,750
Average Annual Growth, Industrial Sector				
2015-2020	-0.09%	0.69%	0.05%	-0.55%
2015-2026	-0.07%	0.94%	0.06%	-0.51%
2015-2027	--	0.93%	0.07%	-0.49%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2016.

Table 3 shows the effect of incorporating updated historical distributed generation adoptions and pending adoptions on projected statewide self-generation impacts. The updated stock for 2015 is slightly lower compared to *CED 2015*, but the large number of pending applications (through mid-2016) for PV systems quickly drive the *CEDU 2016* mid case impacts above those in *CED 2015*. The demand forms accompanying this report provide annual results for the state and each planning area for self-generation, broken out into PV and non-PV technologies.[6]

Table 3: Comparison of *CEDU 2016* and *CED 2015* Mid Case Statewide Self-Generation Impacts

Energy (GWH)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	19,233	19,212	19,212	19,212
2016	21,595	22,924	22,943	22,962
2018	24,209	25,989	26,512	27,028
2020	26,339	27,007	28,523	30,218
2026	36,616	30,535	38,110	46,987
2027	--	31,290	40,164	50,583
Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	3,277	3,256	3,256	3,256
2016	3,777	3,794	3,799	3,804
2018	4,406	4,661	4,783	4,901
2020	4,957	4,957	5,293	5,670
2026	7,407	5,991	7,603	9,496
2027	--	6,197	8,078	10,292

Source: California Energy Commission, Demand Analysis Office, 2016.

Method

The Energy Commission uses detailed models for several key economic sectors to project electricity consumption and peak demand for full *IEPR* forecasts. Staff also estimates simpler, single-equation econometric models for sector electricity

6 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

consumption as well as peak demand and compares the forecast results with those from the more complex models. Typically, both types of models yield similar results at an aggregate, or combined, level.[7] For *CEDU 2016*, staff once again relied on the econometric models, reestimated to incorporate historical data for 2015. **Table 4** shows the key explanatory variables used in the econometric models for each sector and for peak demand. Complete estimation results for each model are provided in Appendix A of this report.

Table 4: Key Explanatory Variables in *CEDU 2016* Econometric Models

Sector	***Key Explanatory Variables***
Residential	Per Capita Income, Electricity Rate, Cooling Degree Days, Heating Degree Days
Commercial	Commercial Employment, Cooling Degree Days
Industrial: Manufacturing	Manufacturing Output, Industrial Electricity Rate
Industrial: Resource Extraction/Construction	Resource Extraction Output, Construction Employment, Percent Employment in Resource Extraction, Industrial Electricity Rate
Agriculture/Water Pumping	Agricultural Electricity Rate, Annual Precipitation
Transportation, Communication, and Utilities	Per Capita Income
Street Lighting	Population
Peak Demand	Unemployment Rate, Maximum Average Daily Temperature, Residential Consumption Per Capita and Residential Electricity Rates

Source: California Energy Commission, Demand Analysis Office, 2016.

To develop estimates of the effects on electricity consumption and demand of updated economic and demographic projections, staff ran the reestimated econometric models

7 See Appendix A in Kavalec, Chris, Nicholas Fugate, Bryan Alcorn, Mark Ciminelli, Asish Gautam, Kate Sullivan, and Malachi Weng-Gutierrez. 2014. *California Energy Demand 2014-2024 Final Forecast, Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency.* California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-200-2013-004-V1-CMF.

twice, once with the projections used in *CED 2015* (from July 2015) and once with newer projections from August 2016. Percentage differences from the two sets of runs were applied to *CED 2015* baseline forecasts extrapolated to 2027,[8] after adjusting for the new historical data (including rates) and netting out impacts that were postprocessed in the 2015 forecast. The latter, which include forecasted impacts of approved efficiency programs, climate change, electric vehicles (EV), other electrification (including ports and high-speed rail), and demand response, were removed since they were not revised in this forecast update.

Staff estimated postprocessed impacts for 2027 in the following manner. For efficiency program impacts, the exponential function used in past forecasts to decay savings was applied for one more year. EV and other electrification impacts were extrapolated, based on growth from 2025-2026. Climate change was assumed to affect temperatures in 2027 by applying percentage increases in temperature from 2025-2026 to 2027. Once the percentage differences from the two sets of econometric runs were applied to the "net" *CED 2015*, the postprocessed impacts were reincorporated and rescaled, if necessary.[9]

As in the full *IEPR* forecasts, *CEDU 2016* includes subregional forecasting analysis for load-serving entities (LSE), local areas, and load pockets[10] within the California ISO control area that is used in the LTPP, TPP, and resource adequacy proceedings. Subregional results are based on disaggregation of planning area results combined with historical billing and hourly load data and are provided in the demand forms accompanying this report.[11] To develop subregional peak demand forecasts, staff estimates weather-normalized peaks for four TAC areas[12] using regression analysis and the latest three years of hourly load data available.[13] The regression results provide weather sensitivity for the latest historical years so that peak demand can be

8 Using the growth rates for 2025-2026.

9 For example, electric vehicle electricity use was rescaled to be incremental to 2015 for consumption and to 2016 for peak demand, since historical consumption and peak demand include any EV load impacts. The impacts of climate change on temperature and degree days were rescaled to account for one more year of historical temperatures, with the impact of climate change growing at the same rate as in *CED 2015* thereafter. High-speed rail use, on the other hand, did not need to be adjusted since projected impacts do not begin until 2022.

10 A *load pocket* is an area in which there is insufficient transmission capability to reliably supply 100 percent of the electric load without relying on generation that is physically located within the area.

11 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

12 The TAC areas include the three IOUs and Valley Electric, and, for Pacific Gas and Electric and Southern California Edison, publicly owned utilities using the IOUs' transmission system.

13 Past forecasts have used the latest single historical year rather than three years for the regression analysis. Staff believes that using three years provides a more robust result that is less sensitive to temperature anomalies that may occur in a year. For more details on weather normalization, see http://www.energy.ca.gov/2011publications/CEC-200-2011-002/CEC-200-2011-002-CTF.pdf.

normalized, assuming average weather ("1 in 2") and extreme weather ("1 in 10") using 30 years of temperature data. Weather-normalized peaks are then projected in a manner consistent with the demand forecasts for the appropriate planning area.[14] Local area peaks within TAC areas are estimated using the latest load data available along with climate zone results and are aligned with TAC totals.

Key Inputs

Projections for 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.[15]

As in *CED 2015,* staff used the IHS Global Insight *Optimistic* economic case for the high demand scenario and Moody's Analytics (Moody's) *Below-Trend Long-Term Growth* case for the low demand scenario. Moody's *Baseline* economic forecast was used for the mid energy demand scenario. For population, the low case again comes from the California Department of Finance (DOF) 2015 long-term population projections, the mid case from IHS Global Insight and the mid and high case from Moody's.[16] **Table 5** provides the key assumptions used by the two companies to develop the three economic scenarios.

14 For example, the Pacific Gas and Electric TAC area peak demand is assumed to grow at the projected rate of the Pacific Gas and Electric planning area.

15 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

16 Population in the low case is identical to that used in *CED 2015*; the DOF has not developed a newer official population forecast. IHS Global Insight and Moody's provide only one scenario for population, unlike other economic and demographic variables.

Table 5: Key Assumptions Embodied in Economic Scenarios

High Demand Scenario (IHS Global Insight Optimistic Scenario), July 2016	Mid Demand Scenario (Moody's Baseline Scenario), July 2016	Low Demand Scenario (Moody's Below-Trend Long-Term Growth Scenario), July 2016
National unemployment rate falls to 4.2 percent by 2018.	National unemployment rate stays below 5 percent through 2018.	The unemployment rate stays higher than in the baseline, just below 5 percent in early 2018.
The UK exit (Brexit) from the European Union will have a negative impact on the U.S. economy via trade channels, however, it will have little long-term impact on foreign growth. Growth in the rest of the world begins to improve with the help of structural reforms implemented by some struggling economies and the European Central Bank's quantitative easing.	Behind this outlook is the expectation that the Federal Reserve will normalize U.S. monetary policy gradually, but the European Central Bank will continue with its extraordinary policy actions until almost the end of the decade. The U.S. dollar has appreciated substantially over the last two years, rising 15 percent. While the long-run fair value euro/dollar exchange rate is an estimated $1.25, the euro is expected to fall briefly below parity with the dollar by this time next year.	The high value of the dollar limits exports, as does the slower than expected Eurozone recovery.
National housing starts climb rapidly, reaching 1.59 million units by the end of 2018.	National housing starts are expected to break 1.9 million units by 2018.	National housing starts reach 1.58 million units by 2018.
Structural oversupply conditions in oil markets keep Brent oil prices low–around $60/barrel for much of 2017. As global oil production increases further, prices will move to higher levels in 2018.	Oil prices are expected to slowly rise. Underlying this outlook is the sharp pullback in investment in North American shale oil production. Global oil demand will also receive a lift from the lower prices. Oil prices are not expected to top $100 per barrel for another decade.	Oil and gas prices fall in the short term.
As the economy improves, the Federal Reserve takes a faster approach to raising interest rates, and the federal funds rate reaches 3.3 percent by 2020.	The Federal Reserve has begun what is expected to be a slow process to normalize monetary policy. Short-term interest rates will not normalize until the second half of 2018, well after the economy has returned to full employment and inflation has returned to the Fed's 2 percent target.	The Fed keeps the fed funds target rate under 2 percent until 2018.
The new president and new Congress will make progress on long-term fiscal priorities. With a stronger outlook and less fiscal uncertainty, both consumer and business confidence improve, and the stock market sees strong gains.	The federal government's fiscal situation is stable. The deficit is expected to be more than $500 billion this fiscal year, equal to 2.8 percent GDP. Deficits and debts will begin to mount again later this decade, given prospects for large increases in entitlement spending.	The pace of economic growth remains below that of the baseline for an extended time for several reasons including a combination of much weaker exports, business investment, household spending, and housing.

Source: Moody's Analytics and IHS Global Insight, 2016

In general, current projections for economic growth in California maintain modest growth similar to those used in *CED 2015*. Both Moody's and IHS Global Insight project growth at a modest pace for key economic variables such as personal income and employment at the national level, which translates, all else equal, to modest growth at the state level.

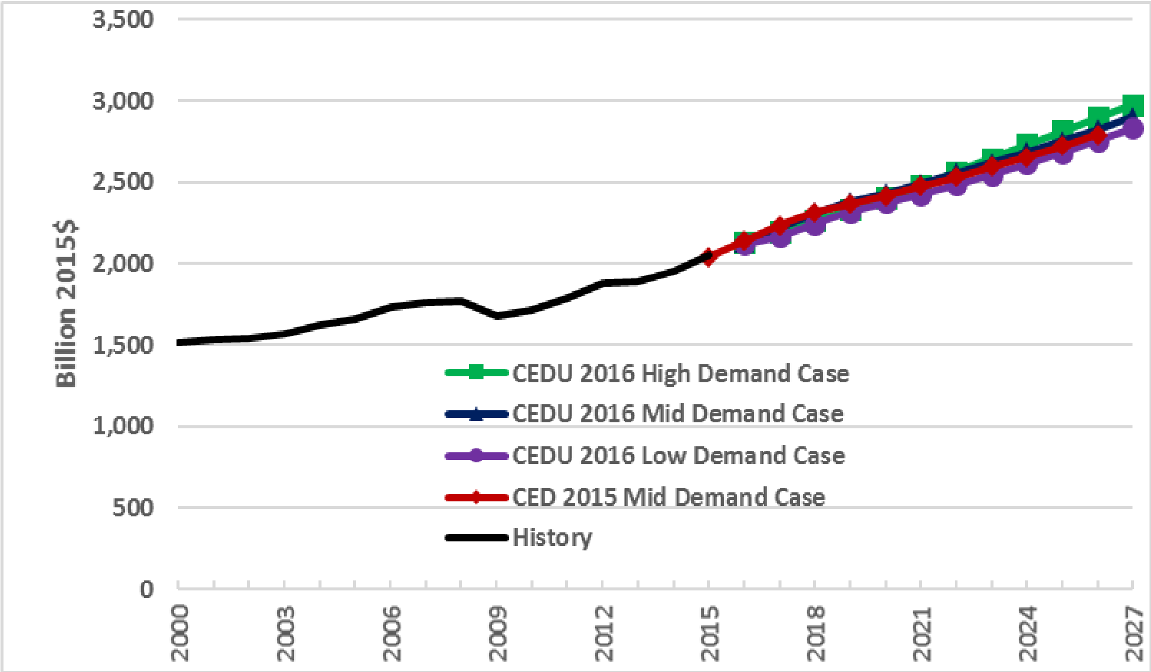
Figure 3 shows historical and projected personal income at the statewide level for the three *CEDU 2016* scenarios and the *CED 2015* mid demand case.[17] By 2026, income is around 1.19 percent higher in the *CEDU 2016* mid case compared to *CED 2015*. Annual growth rates from 2015-2026 average 3.18 percent, 2.94 percent, and 2.71 percent in the *CEDU 2016* high, mid, and low scenarios, respectively, compared to 2.88 percent in the *CED 2015* mid case.

As shown in **Figure 4**, the projection for statewide commercial employment[18] in the *CEDU 2016* mid case is lower than in *CED 2015*. By 2026, commercial employment is around 0.58 percent lower in the new mid case compared to *CED 2015*. Annual growth rates from 2015-2026 average 1.25 percent, 1.17 percent, and 1.06 percent in the *CEDU 2016* high, mid, and low scenarios, respectively, compared to 1.19 percent in the *CED 2015* mid case.

17 To account for periodic revisions to the historical data by Moody's and IHS Global Insight, the *CED 2015* scenarios in this section are scaled so that levels match those used in *CEDU 2016* in 2015.

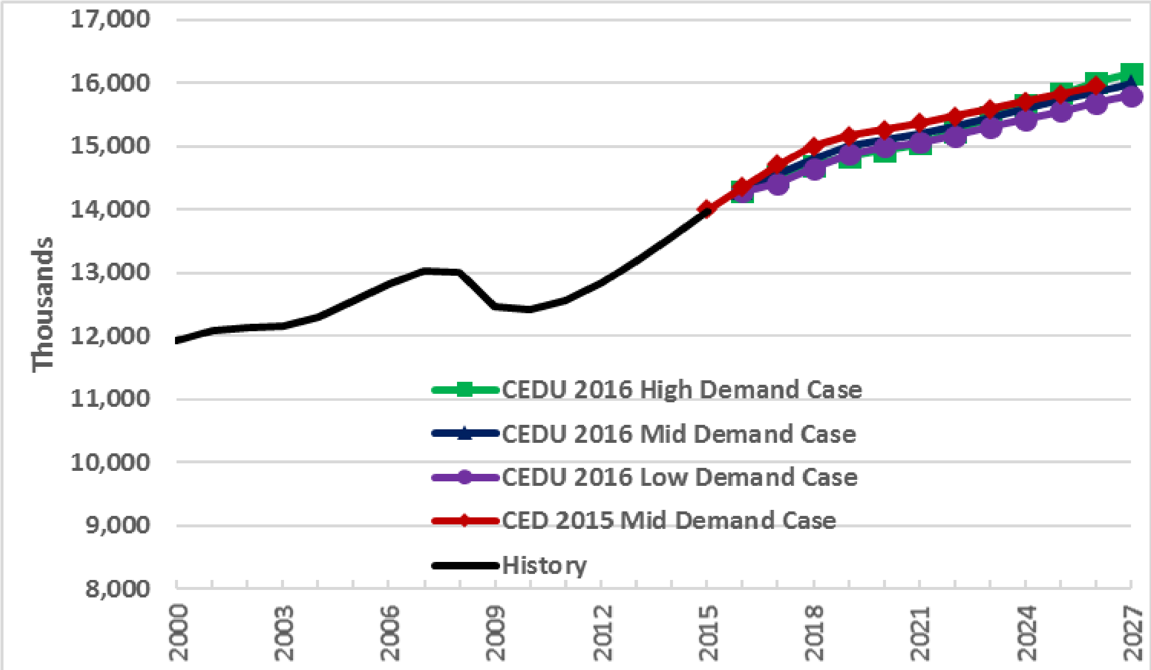
18 Total employment minus employment in the industrial and agricultural sectors.

Figure 3: Statewide Personal Income



Sources: Moody's Analytics and IHS Global Insight, 2015-2016.

Figure 4: Statewide Commercial Employment

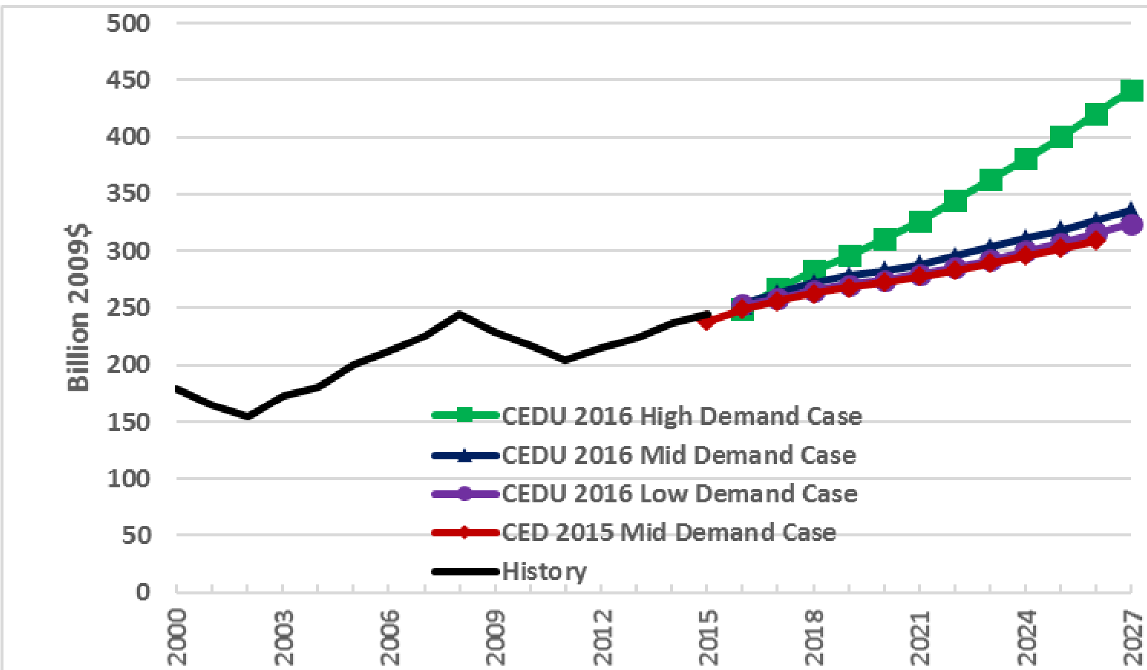


Sources: Moody's Analytics and IHS Global Insight, 2015-2016.

Population in the *CEDU 2016* mid and high demand scenarios differs from the *CED 2015* counterparts. In 2026, population is down 1.13 percent in both the new mid and high cases versus *CED 2015*. Population and other key input data are provided in the demand forms accompanying this report.[19]

Statewide manufacturing dollar output is shown in **Figure 5**, including the three *CEDU 2016* scenarios and the *CED 2015* mid case. By 2026, manufacturing output in the *CEDU 2016* mid case is around 5.58 percent higher than the *CED 2015* mid scenario. As in recent past forecasts, IHS Global Insight is much more optimistic about manufacturing than Moody's; thus, the high scenario is significantly above the mid and low. Annual growth rates from 2015-2026 average 5.07 percent, 2.68 percent, and 2.35 percent in the *CEDU 2016* high, mid, and low scenarios, respectively, compared to 2.38 percent in the *CED 2015* mid case.

Figure 5: Statewide Manufacturing Output



Sources: Moody's Analytics and IHS Global Insight, 2015-2016.

The next chapter provides information on economic and demographic projections at the planning area level. In addition, updated electricity rates, after incorporating historical rates through 2015, are provided.

19 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

CHAPTER 2: Planning Area Results

As in full *IEPR* forecasts, *CEDU 2016* provides results for eight utility planning areas, along with 20 forecast zones within these planning areas.[20] This chapter summarizes results for the five largest planning areas, including Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), the Los Angeles Department of Water and Power (LADWP), and the Northern California Non-California ISO (NCNC). In general, planning area results mirror those at the statewide level, with growth in consumption and peak demand comparable to *CED 2015* as a result of more pessimistic near-term economic projections and optimistic long-term growth. Comprehensive results for all eight planning areas and forecast zones are available electronically as a set of forms posted with this report.[21]

Pacific Gas and Electric Planning Area

The PG&E planning area includes:

- PG&E bundled retail customers.
- Customers served by energy service providers and community choice aggregators[22] using the PG&E distribution system to deliver electricity to end users.
- Customers of publicly owned utilities (POUs) in PG&E's transmission system, with the exception of the Balancing Authority of Northern California, Turlock Irrigation District, and Merced Irrigation District. These entities are now incorporated into the NCNC planning results presented later in this chapter.

Forecast Results

Table 6 compares *CEDU 2016* high, mid, and low demand scenarios with the *CED 2015* mid demand scenario for electricity consumption and peak demand for selected years. Growth in both consumption (2015-2026) and peak demand (2016-2026) in the *CEDU 2016* mid demand case is comparable to *CED 2015*. As in the statewide forecast, these

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20 For a description of the planning areas and climate zones, see pp. 20-26 in Kavalec, Chris, Nick Fugate, Cary Garcia, and Asish Gautam. 2016. *California Energy Demand 2016-2026, Revised Electricity Forecast.* California Energy Commission. Publication Number: CEC-200-2016-001-V1 Available at http://www.energy.ca.gov/2015_energypolicy/documents/#adoptedforecast.

21 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

22 Legislation was passed in 2002 that allows cities, counties, or groups of them to provide electricity to all of the customers within their jurisdictions by becoming community choice aggregators.

results derive from higher growth in personal income and manufacturing output. Growth in commercial employment and population in the updated mid case nearly matches that in the *CED 2015* mid case, which leads to marginal growth in energy demand given the higher growth in the other key inputs.

Table 6: Comparison of *CEDU 2016 and CED 2015* Mid Case Demand Baseline Forecasts of PG&E Electricity Demand

Consumption (GWh)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	83,978	83,978	83,978	83,978
2000	96,609	96,609	96,609	96,609
2015	104,245	104,868	104,868	104,868
2020	108,867	110,610	109,725	108,898
2026	116,259	122,856	118,201	113,540
2027	-	124,658	119,633	114,377
	Average Annual Growth Rates			
1990-2000	1.41%	1.41%	1.41%	1.41%
2000-2015	0.51%	0.55%	0.55%	0.55%
2015-2020	0.87%	1.07%	0.91%	0.76%
2015-2026	1.00%	1.45%	1.09%	0.72%
2015-2027	-	1.45%	1.10%	0.73%
Coincident Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	15,899	15,899	15,899	15,899
2000	18,980	18,980	18,980	18,980
2016*	20,833	21,141	21,141	21,141
2020	21,345	22,046	21,597	21,164
2026	22,065	23,884	22,423	20,650
2027	-	24,185	22,533	20,512
	Average Annual Growth Rates			
1990-2000	1.79%	1.79%	1.79%	1.79%
2000-2016	0.58%	0.68%	0.68%	0.68%
2016-2020	0.61%	1.05%	0.54%	0.03%
2016-2026	0.58%	1.23%	0.59%	-0.23%
2016-2027	-	1.23%	0.58%	-0.27%
Historical values are shaded.				
*Weather normalized: *CEDU 2016* uses 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, 2016.

Table 7 shows the effect of incorporating updated historical distributed generation adoptions and pending adoptions for the PG&E planning area. The updated stock for 2015 is higher compared to *CED 2015.* The large number of pending adoptions (through mid 2016) for PV systems leads to a significant increase in the difference in peak and energy impacts in the *CEDU 2015* mid case versus *CED 2015* throughout the forecast period.

Table 7: Comparison of *CEDU 2016 and CED 2015* Mid Case PG&E Self-Generation Impacts

Energy (GWH)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	8,626	9,612	9,612	9,612
2016	9,665	11,319	11,320	11,322
2018	10,705	12,398	12,615	12,823
2020	11,579	12,833	13,432	14,132
2026	15,744	14,380	17,360	20,827
2027	--	14,692	18,199	22,282
Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	1,437	1,536	1,536	1,536
2016	1,618	1,781	1,781	1,781
2018	1,850	2,066	2,111	2,154
2020	2,048	2,168	2,290	2,432
2026	2,946	2,532	3,131	3,831
2027	--	2,604	3,307	4,131

Source: California Energy Commission, Demand Analysis Office, 2016.

Key Inputs

Table 8 compares the average annual growth rate of the key economic and demographic drivers used in *CEDU 2016* with those used in the *CED 2015* mid case for the PG&E planning area. As in the statewide case, the PG&E planning area shows a significant increase in manufacturing output by 2026; *CEDU 2016* mid case output is around 8.4 percent higher than *CED 2015*. Growth in personal income and commercial employment in the adjusted mid case is up compared to *CED 2015*, which is more than enough to counter the demand-reducing effects of the slight reduction in long-term population growth. Key input data are provided in the demand forms accompanying this report.[23]

Table 8: Comparison of *CEDU 2016* and *CED 2015* Mid Case Economic and Demographic Drivers for the PG&E Planning Area Using Average Annual Growth, 2015-2026

Driver	*CED 2015* Mid Energy Demand	*CEDU 2016* High Energy Demand	*CEDU 2016* Mid Energy Demand	*CEDU 2016* Low Energy Demand
Personal Income	3.05%	3.38%	3.14%	2.90%
Population	1.07%	1.03%	1.03%	1.01%
Manufacturing Output	2.41%	5.00%	2.61%	2.28%
Commercial Employment	1.22%	1.31%	1.24%	1.13%

Source: Moody's Analytics and IHS Global Insight, 2015-2016.

Table 9 shows the effect of updating historical electricity rates on average cost per kilowatt-hour (kWh) in the *CEDU 2016* mid case versus *CED 2015*, by major economic sector. Commercial rates were higher in 2015 than predicted in the previous forecast, while residential and industrial rates were lower, the latter significantly more so. Beyond 2015, rates in the *CEDU 2016* mid case grow at the same rate as *CED 2015.*

Table 9: Comparison of *CEDU 2016* Mid Case and *CED 2015* Mid Case Electricity Rates by Sector for the PG&E Planning Area (2015 cents/kWh)

	Residential		Commercial		Industrial	
Year	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand
2015	17.53	17.15	17.62	18.45	12.55	11.45
2018	18.39	18.00	18.49	19.37	13.14	12.00
2020	19.10	18.69	19.20	20.11	13.65	12.46
2026	19.41	19.00	19.52	20.44	13.87	12.66
2027	--	19.12	--	20.57	--	12.74

Source: California Energy Commission, Demand Analysis Office, 2016.

23 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

Southern California Edison 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 with the exception of Imperial Irrigation District and the cities of Los Angeles, Glendale, and Burbank. Also excluded from the SCE planning area are San Diego County and the southern portion of Orange County, served by SDG&E.

Forecast Results

Table 10 compares *CEDU 2016* high, mid, and low demand scenarios with the *CED 2015* mid demand scenario for electricity consumption and peak demand for selected years. For *CEDU 2016* mid demand case, growth in consumption (2015-2026) is higher than *CED 2015,* while growth in peak demand (2016-2026) is equal to *CED 2015.* By 2026, consumption and peak demand in the updated mid case are around 1.25 percent and 2.67 percent lower than *CED 2015* mid, respectively, due mostly to forecast beginning at lower historical levels. As in the statewide forecast, increased manufacturing output, relative to *CED 2015,* is moderated by slightly less growth in population and commercial employment. Therefore, growth rates in peak remain similar to *CED 2015* projections, while consumption is slightly higher.

Table 10: Comparison of *CEDU 2016* and *CED 2015* Mid Case Demand Baseline Forecasts of SCE Electricity Demand

Consumption (GWh)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	89,041	89,041	89,041	89,041
2000	100,815	100,815	100,815	100,815
2015	109,431	106,080	106,080	106,080
2020	113,250	112,527	111,168	110,041
2026	119,226	122,855	117,732	113,173
2027	--	124,287	118,803	113,754
	Average Annual Growth Rates			
1990-2000	1.25%	1.25%	1.25%	1.25%
2000-2015	0.55%	0.34%	0.34%	0.34%
2015-2020	0.69%	1.19%	0.94%	0.74%
2015-2026	0.78%	1.34%	0.95%	0.59%
2015-2027	-	1.33%	0.95%	0.58%
Coincident Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	17,970	17,970	17,970	17,970
2000	19,829	19,829	19,829	19,829
2016*	22,815	22,224	22,224	22,224
2020	23,006	22,765	22,296	21,944
2026	23,171	24,047	22,553	20,987
2027	-	24,230	22,556	20,784
	Average Annual Growth Rates			
1990-2000	0.99%	0.99%	0.99%	0.99%
2000-2016	0.88%	0.72%	0.72%	0.72%
2016-2020	0.21%	0.60%	0.08%	-0.32%
2016-2026	0.15%	0.79%	0.15%	-0.57%
2016-2027	-	0.79%	0.13%	-0.61%
Historical values are shaded.				
*Weather normalized: *CEDU 2016* uses 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, 2016.

Table 11 shows the effect of incorporating updated historical distributed generation adoptions and pending adoptions for the SCE planning area. As in the statewide results, the updated stock for 2015 is lower compared to *CED 2015,* but the large number of pending applications (through mid 2016) for PV systems eventually drive the *CEDU 2016* mid case impacts to be near those in *CED 2015* for peak demand but less than *CED 2015* for energy. This result is primarily due to the decrease in expected cogeneration facilities over the forecast time horizon while PV capacity continues to grow at the same rates as projected in *CED 2015*.

Table 11: Comparison of *CEDU 2016* and *CED 2015* Mid Case SCE Self-Generation Impacts

Energy (GWH)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	7,162	6,103	6,103	6,103
2016	7,987	7,368	7,377	7,381
2018	9,056	8,489	8,681	8,849
2020	9,876	8,902	9,475	10,057
2026	14,042	10,178	13,303	16,761
2027	-	10,484	14,135	18,192
Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	1,201	1,063	1,063	1,063
2016	1,418	1,268	1,270	1,272
2018	1,700	1,642	1,691	1,732
2020	1,947	1,792	1,927	2,066
2026	3,037	2,278	2,967	3,725
2027	-	2,378	3,179	4,064

Source: California Energy Commission, Demand Analysis Office, 2016.

Key Inputs

Table 12 compares the average annual growth rate of the key economic and demographic drivers used in *CEDU 2016* with those used in the *CED 2015* mid case for the SCE planning area. Growth is reduced for the adjusted mid case for all variables except manufacturing output, which sees a modest increase in growth. By 2026, *CEDU 2016* mid case manufacturing output is around 3.7 percent higher than *CED 2015*. Although, manufacturing output is up, reductions in commercial employment and population keep peak growth rates comparable to *CED 2015,* though consumption growth is somewhat lower. Key input data are provided in the demand forms accompanying this report.[24]

Table 12: Comparison of *CEDU 2016* and *CED 2015* Mid Case Economic and Demographic Drivers for the SCE Planning Area Using Average Annual Growth, 2015-2026

Driver	***CED 2015* Mid Energy Demand**	***CEDU 2016* High Energy Demand**	***CEDU 2016* Mid Energy Demand**	***CEDU* 2016 Low Energy Demand**
Personal Income	2.68%	2.91%	2.67%	2.44%
Population	0.80%	0.73%	0.73%	0.71%
Manufacturing Output	2.21%	5.04%	2.65%	2.32%
Commercial Employment	1.10%	1.11%	1.03%	0.93%

Source: Moody's Analytics and IHS Global Insight, 2015-2016.

Table 13 shows the effect of updating historical electricity rates on average cost per kWh in the *CEDU 2016* mid case versus *CED 2015*, by major economic sector. Residential and industrial average rates were lower in 2015 than were predicted in the previous forecast, while commercial rates are nearly the same. Beyond 2015, rates in the *CEDU 2016* mid case grow at the same rate as *CED 2015*.

Table 13: Comparison of *CEDU 2016* Mid Case and *CED 2015* Mid Case Electricity Rates by Sector for the SCE Planning Area (2015 cents/kWh)

	Residential		**Commercial**		**Industrial**	
Year	***CED 2015* Mid Energy Demand**	***CEDU 2016* Mid Energy Demand**	***CED 2015* Mid Energy Demand**	***CEDU 2016* Mid Energy Demand**	***CED 2015* Mid Energy Demand**	***CEDU 2016* Mid Energy Demand**
2015	17.32	16.52	14.55	14.66	11.79	11.39
2018	17.85	17.04	14.71	14.82	12.09	11.68
2020	18.71	17.85	15.31	15.41	12.75	12.31
2026	19.90	18.99	15.89	16.00	13.29	12.83
2027	--	19.33	--	16.22	--	13.03

Source: California Energy Commission, Demand Analysis Office, 2016.

24 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

San Diego Gas & Electric Planning Area

The SDG&E 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.

Forecast Results

Table 14 compares *CEDU 2016* high, mid, and low demand scenarios with the *CED 2015* mid demand scenario for electricity consumption and peak demand for selected years. Growth in both consumption (2015-2026) and in peak demand (2016-2026) in the *CEDU 2016* mid demand case is comparable to *CED 2015*. As in the statewide forecast, growth remains comparable to *CED 2015*. Although the SDG&E planning area sees increased growth in consumption due to faster personal income and manufacturing output growth, the mediating effects of behind-the-meter PV keeps peak demand flat. By 2026, consumption and peak demand in the updated mid case are around 0.5 percent and 3.8 percent lower than in *CED 2015* mid, respectively. The larger difference for peak demand results from an estimated weather-normalized peak for 2016 below that estimated for 2015.

Table 14: Comparison of *CEDU 2016* and *CED 2015* Mid Case Demand Baseline Forecasts of SDG&E Electricity Demand

Consumption (GWh)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	14,857	14,857	14,857	14,857
2000	18,784	18,784	18,784	18,784
2015	21,581	21,308	21,308	21,308
2020	22,572	22,429	22,185	21,990
2026	24,165	24,983	24,045	23,049
2027	-	25,352	24,354	23,230
	Average Annual Growth Rates			
1990-2000	2.37%	2.37%	2.37%	2.37%
2000-2015	0.93%	0.84%	0.84%	0.84%
2015-2020	0.90%	1.03%	0.81%	0.63%
2015-2026	1.03%	1.46%	1.10%	0.72%
2015-2027	-	1.46%	1.12%	0.72%
Coincident Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	2,978	2,978	2,978	2,978
2000	3,485	3,485	3,485	3,485
2016*	4,606	4,448	4,448	4,448
2020	4,654	4,565	4,455	4,378
2026	4,705	4,830	4,525	4,188
2027	-	4,870	4,530	4,149
	Average Annual Growth Rates			
1990-2000	1.58%	1.58%	1.58%	1.58%
2000-2016	1.76%	1.54%	1.54%	1.54%
2016-2020	0.26%	0.65%	0.04%	-0.40%
2016-2026	0.21%	0.83%	0.17%	-0.60%
2016-2027	-	0.83%	0.17%	-0.63%
Historical values are shaded.				
*Weather normalized: *CEDU 2016* uses 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, 2016.

Table 15 shows the effect of incorporating updated historical distributed generation adoptions and pending adoptions for the SDG&E planning area. As in the statewide results, the updated stock for 2015 is slightly lower compared to *CED 2015,* but the large number of pending applications (through mid-2016) for PV systems eventually drive the *CEDU 2016* mid case impacts above those in *CED 2015* for both peak demand and energy.

Table 15: Comparison of *CEDU 2016* and *CED 2015* Mid Case SDG&E Self-Generation Impacts

Energy (GWH)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	1,550	1,586	1,586	1,586
2016	1,842	2,089	2,089	2,089
2018	2,175	2,387	2,447	2,493
2020	2,419	2,465	2,671	2,846
2026	3,414	2,831	3,585	4,377
2027	-	2,904	3,767	4,679
Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	213	188	188	188
2016	226	216	217	224
2018	263	256	271	287
2020	304	287	311	333
2026	404	374	411	442
2027	-	400	439	471

Source: California Energy Commission, Demand Analysis Office, 2016.

Key Inputs

Table 16 compares the average annual growth rate of the key economic and demographic drivers used in *CEDU 2016* with those used in the *CED 2015* mid case for the SDG&E planning area. As with the statewide forecast, growth in income and manufacturing output is up for the adjusted mid case, while population and commercial employment growth is comparable to *CED 2015.* The largest increase in growth is for manufacturing output: by 2026, *CEDU 2016* mid case income is around 8.5 percent higher than *CED 2015*, which is greater than other Southern California areas and similar to Northern California growth, except for the NCNC planning area. Key input data are provided in the demand forms accompanying this report.[25]

Table 16: Comparison of *CEDU 2016 and CED 2015* Mid Case Economic and Demographic Drivers for the SDG&E Planning Area Using Average Annual Growth, 2015-2026

Driver	*CED 2015* Mid Energy Demand	*CEDU 2016* High Energy Demand	*CEDU 2016* Mid Energy Demand	*CEDU* 2016 Low Energy Demand
Personal Income	2.79%	3.18%	2.94%	2.71%
Population	0.75%	0.75%	0.75%	0.73%
Manufacturing Output	2.48%	5.08%	2.69%	2.36%
Commercial Employment	1.28%	1.36%	1.28%	1.17%

Source: Moody's Analytics and IHS Global Insight, 2015-2016.

Table 17 shows the effect of updating historical electricity rates on average cost per kWh in the *CEDU 2016* mid case versus *CED 2015*, by major economic sector. Rates in all three sectors were significantly higher in 2015 than had been predicted in the previous forecast. Beyond 2015, rates in the *CEDU 2016* mid case grow at the same rate as *CED 2015*.

Table 17: Comparison of *CEDU 2016* Mid Case and *CED 2015* Mid Case Electricity Rates by Sector for the SDG&E Planning Area (2015 cents/kWh)

	Residential		Commercial		Industrial	
Year	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand
2015	17.45	20.80	16.69	20.93	11.53	13.43
2018	18.47	20.02	16.95	19.63	11.71	12.41
2020	19.66	21.31	17.72	20.52	12.24	12.98
2026	20.47	22.17	17.99	20.84	12.43	13.18
2027	--	22.41	--	21.05	--	13.31

Source: California Energy Commission, Demand Analysis Office, 2016.

25 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

Los Angeles Department of Water and Power 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.

Forecast Results

Table 18 compares *CEDU 2016* high, mid, and low demand scenarios with the *CED 2015* mid demand scenario for electricity consumption and peak demand for selected years. Growth in both consumption (2015-2026) and peak demand (2016-2026) is slower in the *CEDU 2016* mid demand case versus *CED 2015*. As in the statewide forecast and other planning areas, higher energy demand is derived from higher income and manufacturing output growth mitigated by lower population growth and commercial employment. By 2026, consumption is around 4.3 percent higher, while peak demand is 2.0 percent lower in the updated mid case than in *CED 2015* mid case.

Table 18: Comparison of *CEDU 2016* and *CED 2015* Mid Case Demand Baseline Forecasts of LADWP Electricity Demand

Consumption (GWh)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	23,038	23,038	23,038	23,038
2000	24,014	24,014	24,014	24,014
2015	24,621	25,570	25,570	25,570
2020	25,487	26,563	26,365	25,802
2026	27,188	29,583	28,346	26,580
2027	-	30,048	28,706	26,742
	Average Annual Growth Rates			
1990-2000	0.42%	0.42%	0.42%	0.42%
2000-2015	0.17%	0.42%	0.42%	0.42%
2015-2020	0.69%	0.76%	0.61%	0.18%
2015-2026	0.91%	1.33%	0.94%	0.35%
2015-2027	-	1.35%	0.97%	0.37%
Coincident Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	5,341	5,341	5,341	5,341
2000	5,344	5,344	5,344	5,344
2016*	6,039	5,968	5,968	5,968
2020	6,163	6,107	6,019	5,876
2026	6,373	6,527	6,244	5,772
2027	-	6,600	6,282	5,751
	Average Annual Growth Rates			
1990-2000	0.01%	0.01%	0.01%	0.01%
2000-2016	0.77%	0.69%	0.69%	0.69%
2016-2020	0.51%	0.58%	0.21%	-0.39%
2016-2026	0.54%	0.90%	0.45%	-0.33%
2016-2027	-	0.92%	0.47%	-0.34%
Historical values are shaded.				
*Weather normalized: *CEDU 2016* uses 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, 2016.

Table 19 shows the effect of incorporating updated historical distributed generation adoptions and pending adoptions for the LADWP planning area. Updated stock for 2015 is higher compared to *CED 2013,* and this, combined with pending applications (through mid 2016) for PV systems, keeps the *CEDU 2016* mid case impacts above those in *CED 2015* for both peak demand and energy.

Table 19: Comparison of *CEDU 2016* and *CED 2015* Mid Case LADWP Self-Generation Impacts

Energy (GWH)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	1,540	1,533	1,533	1,533
2016	1,673	1,690	1,694	1,699
2018	1,763	2,185	2,209	2,254
2020	1,857	2,228	2,289	2,402
2026	2,275	2,378	2,662	3,175
2027	-	2,403	2,736	3,332
Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	269	277	277	277
2016	291	281	283	285
2018	311	365	372	385
2020	333	376	392	424
2026	438	414	489	625
2027	--	420	508	665

Source: California Energy Commission, Demand Analysis Office, 2016.

Key Inputs

Table 20 compares the average annual growth rate of the key economic and demographic drivers used in *CEDU 2016* with those used in the *CED 2015* mid case for the LADWP planning area. As in most of the other planning areas, growth is up for the adjusted mid case for personal income and manufacturing output compared to *CED 2015*. By 2026, *CEDU 2016* mid case personal income is around 3.8 percent higher than *CED 2015*, the largest difference between the older and newer income projections mid case among the planning areas. Key input data are provided in the demand forms accompanying this report.[26]

26 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

Table 20: Comparison of *CEDU 2016* and *CED 2015* Mid Case Economic and Demographic Drivers for the LADWP Planning Area Using Average Annual Growth, 2015-2026

Driver	*CED 2015* Mid Energy Demand	*CEDU 2016* High Energy Demand	*CEDU 2016* Mid Energy Demand	*CEDU* 2016 Low Energy Demand
Personal Income	2.93%	3.21%	2.97%	2.73%
Population	0.80%	0.76%	0.76%	0.73%
Manufacturing Output	2.56%	5.17%	2.78%	2.45%
Commercial Employment	1.23%	1.37%	1.22%	1.12%

Source: Moody's Analytics and IHS Global Insight, 2015-2016.

Table 21 shows the effect of updating historical electricity rates on average cost per kWh in the *CEDU 2016* mid case versus *CED 2015*, by major economic sector. Estimated historical rates in all three sectors in 2015 are lower than what was predicted in the previous forecast. Beyond 2015, rates in the *CEDU 2016* mid case grow at the same rate as *CED 2015*.

Table 21: Comparison of *CEDU 2016* Mid Case and *CED 2015* Mid Case Electricity Rates by Sector for the LADWP Planning Area (2015 cents/kWh)

	Residential		Commercial		Industrial	
Year	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand
2015	15.55	15.38	16.86	14.92	14.19	14.16
2018	17.11	16.20	18.01	15.73	15.42	14.88
2020	17.67	16.64	18.34	16.20	15.82	15.32
2026	18.49	17.41	18.68	16.49	16.34	15.83
2027	-	17.54	-	16.57	-	16.39

Source: California Energy Commission, Demand Analysis Office, 2016.

Northern California Non-California ISO Planning Area

The NCNC planning area includes Sacramento Municipal Utility District (SMUD) retail customers, Merced and Turlock Irrigations Districts, as well as the remaining members of the Balancing Authority of Northern California.

Forecast Results

Table 22 compares *CEDU 2016* high, mid, and low demand scenarios with the *CED 2015* mid demand scenario for electricity consumption and peak demand for selected years. Unlike the other planning areas, growth in both consumption (2015-2026) and peak demand (2016-2026) is projected to be faster in the *CEDU 2016* mid demand case versus *CED 2015* but begin at a much lower level, reflecting a more pessimistic outlook for the Northern and Central Valley areas. Increases in growth derive from faster growth in personal income and manufacturing output. By 2026, consumption and peak demand in the updated mid case are around 3.4 percent and 3.8 percent lower than in *CED 2015* mid, respectively, primarily the result of lower starting points for consumption and peak.

Table 22: Comparison of *CEDU 2016* and *CED 2015* Mid Case Demand Baseline Forecasts of NCNC Electricity Demand

Consumption (GWh)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	12,702	12,702	12,702	12,702
2000	15,996	15,996	15,996	15,996
2015	18,793	17,912	17,912	17,912
2020	20,033	19,133	19,050	18,798
2026	21,507	21,396	20,677	19,769
2027	-	21,736	20,956	19,947
	Average Annual Growth Rates			
1990-2000	2.33%	2.33%	2.33%	2.33%
2000-2015	1.08%	0.76%	0.76%	0.76%
2015-2020	1.29%	1.33%	1.24%	0.97%
2015-2026	1.23%	1.63%	1.31%	0.90%
2015-2027	-	1.63%	1.32%	0.90%
Coincident Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
1990	3,731	3,731	3,731	3,731
2000	4,516	4,516	4,516	4,516
2016*	5,181	4,991	4,991	4,991
2020	5,430	5,291	5,233	5,148
2026	5,767	5,760	5,572	5,275
2027	-	5,840	5,626	5,291
	Average Annual Growth Rates			
1990-2000	1.93%	1.93%	1.93%	1.93%
2000-2016	0.86%	0.63%	0.63%	0.63%
2016-2020	1.18%	1.47%	1.19%	0.78%
2016-2026	1.08%	1.44%	1.11%	0.56%
2016-2027	-	1.44%	1.10%	0.53%
Historical values are shaded.				
*Weather normalized: *CEDU 2016* uses 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, 2016.

Table 23 shows the effect of incorporating updated historical distributed generation adoptions and pending adoptions for the SMUD planning area. Updated stock for 2015 is lower compared to *CED 2015*, but pending applications (through mid 2016) for PV systems push the *CEDU 2016* mid case impacts above those in *CED 2015* for both peak demand and energy by the end of the forecast period.

Table 23: Comparison of *CEDU 2016* and *CED 2015* Mid Case NCNC Self-Generation Impacts

Energy (GWH)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	274	299	299	299
2016	324	360	363	369
2018	385	420	443	482
2020	460	459	517	619
2026	838	591	917	1,437
2027	-	616	1,008	1,629
Peak (MW)				
	CED 2015 Mid Energy Demand	***CEDU 2016 High Energy Demand***	***CEDU 2016 Mid Energy Demand***	***CEDU 2016 Low Energy Demand***
2015	63	69	69	69
2016	72	74	75	76
2018	86	84	88	96
2020	103	91	103	123
2026	190	117	181	284
2027	-	122	199	322

Source: California Energy Commission, Demand Analysis Office, 2016.

Key Inputs

Table 24 compares the average annual growth rate of the key economic and demographic drivers used in *CEDU 2016* with those used in the *CED 2015* mid case for the NCNC planning area. Growth is up in the adjusted mid case for personal income and manufacturing output compared to *CED 2015*. Although growing at a slightly faster rate, by 2026 *CEDU 2016* mid case income is around 3.9 percent lower than *CED 2015*, reflecting the updated economic conditions at the start of the forecast. Key input data are provided in the demand forms accompanying this report.[27]

27 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

Table 24: Comparison of *CEDU 2016* and *CED 2015* Mid Case Economic and Demographic Drivers for the SMUD Planning Area Using Average Annual Growth, 2013-2024

Driver	*CED 2015* Mid Energy Demand	*CEDU 2016* High Energy Demand	*CEDU 2016* Mid Energy Demand	*CEDU* 2016 Low Energy Demand
Personal Income	3.01%	3.32%	3.09%	2.85%
Population	1.21%	1.20%	1.20%	1.18%
Manufacturing Output	3.10%	6.26%	3.84%	3.51%
Commercial Employment	1.32%	1.32%	1.23%	1.13%

Source: Moody's Analytics and IHS Global Insight, 2015-2016.

Table 25 shows the effect of updating historical electricity rates on average cost per kWh in the *CEDU 2016* mid case versus *CED 2015*, by major economic sector. Estimated historical rates in the commercial sector in 2015 in the updated forecast are below those predicted for *CED 2015*, while residential and industrial rates are slightly higher. Beyond 2013, rates in the *CEDU 2016* mid case grow at the same rate as *CED 2015*.

Table 25: Comparison of *CEDU 2016* Mid Case and *CED 2015* Mid Case Electricity Rates by Sector for the NCNC Planning Area (2015 cents/kWh)

	Residential		Commercial		Industrial	
Year	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand	*CED 2015* Mid Energy Demand	*CEDU 2016* Mid Energy Demand
2015	14.23	14.60	14.21	13.59	10.59	10.71
2018	14.83	15.21	14.51	13.88	10.80	10.91
2020	15.10	15.49	14.55	13.92	10.83	10.95
2026	16.25	16.67	14.96	14.31	11.13	11.25
2027	-	16.87	-	14.37	-	11.30

Source: California Energy Commission, Demand Analysis Office, 2016.

CHAPTER 3: Updated Additional Achievable Energy Efficiency Savings Estimates

For *CED 2015*, the Energy Commission, along with the CPUC and Navigant Consulting, developed scenarios for AAEE savings for IOU service territories based on the CPUC's *2015 California Energy Efficiency Potential and Goals Study*.[28] Combinations of the three *CED 2015* baseline demand scenarios and the five AAEE scenarios provided options to be used as managed forecasts for resource planning, combining "business-as-usual" projections with additional efficiency savings deemed likely to occur.

The Energy Commission, together with the CPUC and the California ISO, settled on two combinations of baseline and AAEE forecasts as managed forecasts to be used for planning: the *CED 2015* mid baseline demand case combined with the mid AAEE scenario for systemwide analyses and the mid baseline case combined with the low-mid AAEE scenario for more localized studies.[29] This chapter provides updated data for these two managed forecasts, mid and low-mid AAEE cases rescaled to be incremental to 2015 for electricity sales and to 2016 for utility peak demand.[30] Savings for 2027 for the two AAEE scenarios were estimated by Navigant Consulting.

Results

Tables 26 and **27** show the rescaled projected savings from AAEE for each IOU service territory and the three IOUs combined for 2015-2026 for the mid and low-mid AAEE scenarios, respectively. These savings are subtracted directly from IOU service territory sales and peak forecasts to provide updated managed forecasts. Impacts of the managed forecasts are reflected in the subregional demand forms (1.1c and 1.5) accompanying this report.[31]

In addition to revised IOU savings estimates, *CED 2015* also introduced savings estimates for the two largest POUs, LADWP and SMUD. These estimates produced

28 Available at http://www.cpuc.ca.gov/General.aspx?id=2013.

29 For a full description of the AAEE scenarios, see Chapter 2 in Kavalec, Chris, Nick Fugate, Cary Garcia, and Asish Gautam. 2016. *California Energy Demand 2016-2026, Revised Electricity Forecast.* California Energy Commission. Publication Number: CEC-200-2016-001-V1 Available at http://www.energy.ca.gov/2015_energypolicy/documents/#adoptedforecast.

30 Rescaling is necessary since historical consumption and peak demand include any AAEE load impacts that have already occurred.

31 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-05.

several scenarios consistent with Navigant Consulting's estimates for IOUs as well as baseline demand case assumptions. For *CEDU 2016*, these estimates were extrapolated to 2027 and underwent the same rescaling procedure to measure incremental impacts. These savings estimates are provided in the accompanying demand forms along with IOU savings estimates.

Table 26: AAEE Savings by Utility, Mid AAEE Scenario

Energy Savings (GWH)				
Year	**PG&E**	**SCE**	**SDG&E**	**IOUs Combined**
2015	51	59	27	137
2016	722	821	208	1,751
2017	1,471	1,698	414	3,582
2018	2,407	2,737	646	5,790
2019	3,071	3,505	810	7,385
2020	3,679	4,206	953	8,838
2021	4,356	4,964	1,112	10,432
2022	5,004	5,690	1,272	11,966
2023	5,666	6,450	1,438	13,554
2024	6,300	7,181	1,596	15,076
2025	6,937	7,912	1,751	16,600
2026	7,572	8,652	1,903	18,128
2027	8,181	9,358	2,038	19,577
Peak Demand Savings* (MW)				
Year	**PG&E**	**SCE**	**SDG&E**	**IOUs Combined**
2016	162	192	43	396
2017	329	394	88	811
2018	546	642	143	1,331
2019	711	838	184	1,733
2020	872	1,030	224	2,126
2021	1,049	1,232	267	2,547
2022	1,216	1,424	309	2,949
2023	1,394	1,625	352	3,371
2024	1,571	1,826	395	3,792
2025	1,752	2,030	439	4,220
2026	1,935	2,237	483	4,654
2027	2,115	2,438	526	5,078

*Includes estimated transmission and distribution losses.
Source: California Energy Commission, Demand Analysis Office, 2016.

Table 27: AAEE Savings by Utility, Low-Mid AAEE Scenario

Energy Savings (GWH)				
Year	**PG&E**	**SCE**	**SDG&E**	**IOUs Combined**
2015	41	49	25	114
2016	649	745	192	1,585
2017	1,328	1,533	379	3,240
2018	1,884	2,167	520	4,571
2019	2,358	2,724	636	5,718
2020	2,774	3,220	730	6,724
2021	3,255	3,777	842	7,874
2022	3,719	4,303	952	8,974
2023	4,192	4,865	1,069	10,127
2024	4,653	5,414	1,180	11,247
2025	5,118	5,972	1,295	12,385
2026	5,597	6,546	1,413	13,556
2027	6,058	7,089	1,518	14,665
Peak Demand Savings* (MW)				
Year	**PG&E**	**SCE**	**SDG&E**	**IOUs Combined**
2016	136	161	38	335
2017	279	330	78	687
2018	411	486	113	1,010
2019	536	641	145	1,321
2020	654	791	174	1,619
2021	781	947	206	1,934
2022	904	1,100	237	2,241
2023	1,032	1,262	269	2,563
2024	1,158	1,423	301	2,882
2025	1,284	1,580	334	3,199
2026	1,416	1,742	367	3,526
2027	1,549	1,899	401	3,849

*Includes estimated transmission and distribution losses.
Source: California Energy Commission, Demand Analysis Office, 2016.

CHAPTER 4: Peak-Shift Scenario Analysis

As demand modifiers such as PV, efficiency, time-of-use (TOU) pricing, and electric vehicles affect load to a growing degree, hourly load profiles may change to the extent that peak load provided by load-serving entities may occur at a different hour of the day. In particular, PV generation may shift utility peaks to a later hour as a significant part of load at traditional peak hours (late afternoon) is served by PV, with generation dropping off quickly as the evening hours approach. For *CEDU 2016*, staff developed a scenario analysis of potential peak shift and the resulting impact on peak demand served by utilities for the IOU planning (TAC) areas for the managed forecast (that is, the mid baseline case combined with mid AAEE). The results of the *final adjusted managed peak* scenario analysis can be used by the California ISO in TPP studies to review previously -approved projects or procurement of existing resource adequacy resources to maintain local reliability but should not be used in identifying new needs triggering new transmission projects, given the preliminary analysis. More complete analyses will be developed for *IEPR* forecasts once full hourly load forecasting models are developed.

The *CEDU 2016* scenario analysis consisted of three main components:

- Hourly load profiles for PV generation
- Hourly load profiles for AAEE savings
- Projected weather-normalized hourly end-use loads for each of 8,760 hours for each year, *where end-use load is defined as utility-supplied load including line losses plus PV generation plus avoided line losses*

The impacts of TOU and electric vehicles were not included in the scenario analysis, as estimated load shapes for these modifiers are very preliminary and require more data and study.

Hourly load profiles for PV generation were developed based on analysis of California Solar Initiative[32] data.[33] Simulated hourly profiles for each IOU were averaged over a four-year period (2009-2012) to calculate an average annual hourly profile. For each forecast year, the profiles were applied to *CEDU 2016* projected annual PV energy to give estimated generation in each hour.

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32 The California Solar Initiative (CSI) program provides incentives to for solar systems installed on existing residential homes, existing and new commercial, industrial, government, non-profit, and agricultural properties within the service territories of the state's three investor-owned utilities.

33 Unpublished analysis by Energy and Environmental Economic, Inc. The simulated PV production data from this analysis was provided to Energy Commission staff by Tim Drew at the CPUC.

To translate AAEE savings to into hourly projections, staff, with the assistance of Navigant Consulting, estimated load profiles by end-use categories (for example, lighting) using shapes derived from the Database for Energy Efficiency Resources, as well as other sources. These profiles were applied to projected AAEE savings by end-use category for each year and aggregated to give total estimated hourly impacts. A staff paper detailing this process is available upon request.[34]

To develop a model to project hourly end-use loads, staff estimated separate regressions for each of the 24 hours for each IOU TAC area using California ISO energy management system (EMS) hourly load data for 2006-2012. EMS data measure total load served by LSEs for each IOU TAC area. The year 2006 is the first for which full EMS data is available, and 2012 was selected as the last year because later years begin to show a significant impact from PV (reduced load) and are therefore less representative of total end-use load for each hour.

The hourly regressions specified end-use load divided by the overall average hourly load for the corresponding year as a function of temperature variables as well as calendar effects from day of the week, weekend and holiday, and month of the year. Dummy variables for each year were also included. A ratio was used rather than actual hourly consumption in order to apply *CEDU 2016* forecast results for annual (cumulative) end-use load directly to the estimated ratios for each year to give preliminary 8,760 hourly loads. This specification avoids the requirement that the hourly model account for economic and demographic growth since these factors are already built into the *CEDU 2016* annual results. A single temperature for each hour for each IOU was developed by measuring through regression the effect of temperatures from weather stations within each IOU TAC on daily TAC load and weighting each weather station accordingly. **Table 28** shows the explanatory variables for the hourly regressions.[35] Estimation results for all 72 regressions are available upon request.

34 Jaske, Michael. 2016. *Translating Aggregate Energy Efficiency Savings Projections Into Hourly System Impacts.* California Energy Commission. Publication Number CEC-200-2016-007. http://www.energy.ca.gov/2016publications/CEC-200-2016-007/CEC-200-2016-007.pdf.

35 The temperature variables were estimated using linear *splines* to capture differences in the load-temperature relationship for different levels of temperature. For example, the hourly temperature variable was estimated with splines for temperatures below 60 degrees Fahrenheit, 60-70 degrees, 70-80 degrees, 80-90 degrees, and above 90 degrees.

Table 28: Hourly Load Regression Explanatory Variables

Hourly Temperature	Minimum Hourly Temperature, Previous 24 Hours
Hourly Temperature 24 Hours Previous	Dummy Variable: Day of Week
Hourly Temperature 48 Hours Previous	Dummy Variable: Weekend/Holiday
Hourly Temperature 72 Hours Previous	Dummy Variable: Month
Average Hourly Temperature, Previous 24 Hours	Dummy Variable: Year

Source: Demand Analysis Office, California Energy Commission, 2016

To project weather-normalized hourly consumption loads for 2016-2027 with the estimated regression coefficients, staff developed an "average weather" year for hourly temperatures using a technique applied by the Electric Reliability Council of Texas to forecast long-term hourly loads.[36] This process begins by assigning a month for annual peak hourly consumption load for each IOU. Based on historical frequency of peak occurrence, PG&E was assigned July, and SCE and SDG&E were assigned September. Next, annual maximum hourly temperatures for each IOU were averaged over the 2000-2015 period. Hourly temperatures for this peak month were assigned by choosing the actual historical month (July or September) with a maximum hourly temperature closest to the average annual maximum over the 16-year period. A similar procedure was used for the coldest annual hourly temperatures, assuming December as the coldest month for all three IOUs.[37] For the remaining months, historical temperatures were assigned by calculating the average monthly minimum (for January and February) or average monthly maximum (the rest of the months) over 2000-2015 and selecting the historical month with a minimum or maximum hourly temperature closest to the historical average for that month.

Once the "average weather" year was developed for hourly temperatures for each IOU, the hourly model and associated regression coefficients, along with annual end-use load forecasts from *CEDU 2016,* were applied to produce a preliminary set of 8,760 loads for each forecast year. Then, projected peak hourly end-use load for each year was calibrated to match the *CEDU 2016* forecasts for annual peak served by utilities (including line losses) plus PV generation at the conventional peak hour (plus avoided line losses).[38]

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36 http://www.ercot.com/gridinfo/load/2013_Long-Term_Hourly_Peak_Demand_and_Energy_Forecast.pdf.

37 For all three IOUs, December yielded the annual minimum hourly temperature most frequently.

38 Calibration involved slight adjustments to the estimated load response of the highest temperatures.

For each year, hourly estimates of PV generation and AAEE savings (including avoided losses) were then subtracted from hourly end-use load to give estimates of loads served by utilities in each IOU planning area. The annual maximum of these hourly loads represents an adjusted peak projection for a given year that incorporates peak-shift brought about by PV and AAEE, peaks that now occur at a later hour. The difference between these peaks and *CEDU 2016* projected utility-served managed peaks (that is, the mid baseline case combined with mid AAEE) for each year gives a preliminary annual peak-shift adjustment for 2016-2027. Since the *CEDU 2016* peak for 2016 is based on actual historical loads and therefore incorporates any peak-shift that may have already occurred,[39] the annual adjustments were recalculated to be incremental to 2016.

Table 29 shows for PG&E the *CEDU 2016* projected utility-served peaks for the mid case managed forecast, the preliminary (upward) adjustment for peak shift, and the resulting preliminary adjusted peak for 2016-2027. **Figure 6** provides a graph of the PG&E results. **Table 30** and **Figure 7** show the results in similar fashion for SCE, with SDG&E results shown in **Table 31** and **Figure 8**. By 2027, the preliminary peak-shift adjustments range from about 700 MW for SDG&E to around 1,600 MW for PG&E.

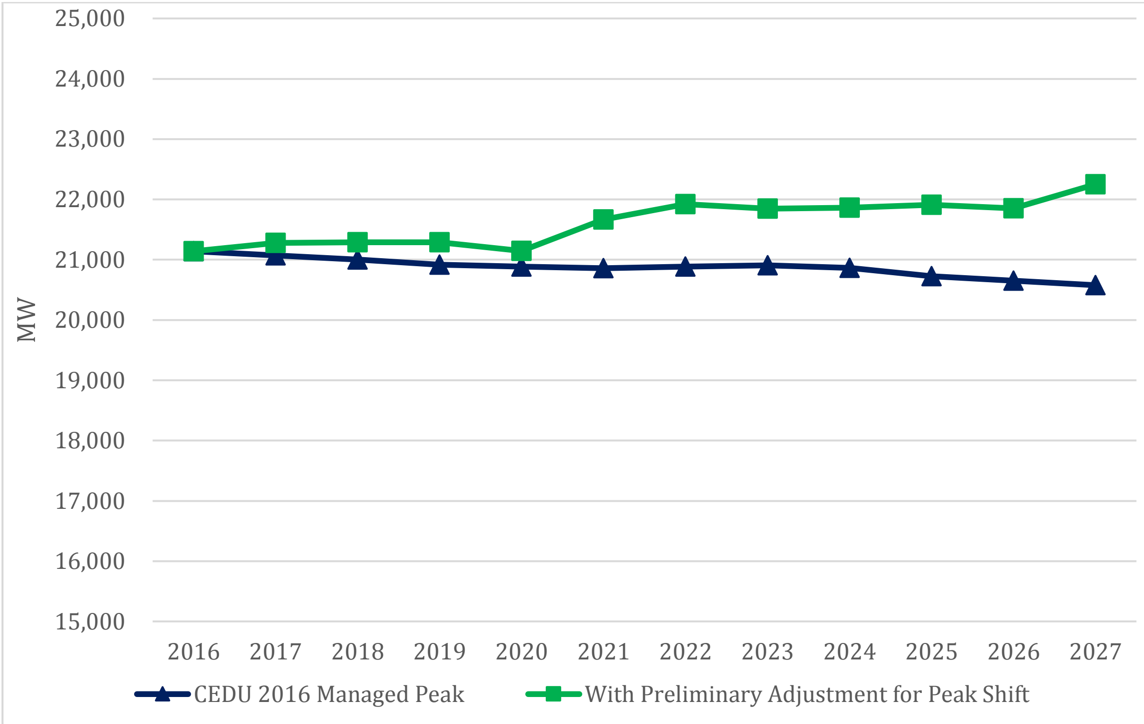
Table 29: CEDU 2016 Managed Peak, Preliminary Peak-Shift Adjustment, and Preliminary Adjusted Managed Peak for the PG&E Planning Area (MW)

	CEDU 2016 **Managed Peak**	**Preliminary Peak-Shift Adjustment**	**Preliminary Adjusted Managed Peak**
2016	21,141	--	21,141
2017	21,071	207	21,278
2018	21,000	289	21,290
2019	20,920	367	21,287
2020	20,887	260	21,147
2021	20,861	805	21,666
2022	20,887	1,036	21,923
2023	20,905	942	21,847
2024	20,862	999	21,861
2025	20,727	1,185	21,912
2026	20,650	1,200	21,850
2027	20,579	1,668	22,248

Source: Demand Analysis Office, California Energy Commission, 2016

39 Indeed, all three IOUs in 2016 peaked at a later hour than that typically assumed in the *IEPR* forecasts.

Figure 6: *CEDU 2016* Managed Peak Forecast and Managed Forecast with Preliminary Adjustment for Peak Shift, PG&E Planning Area



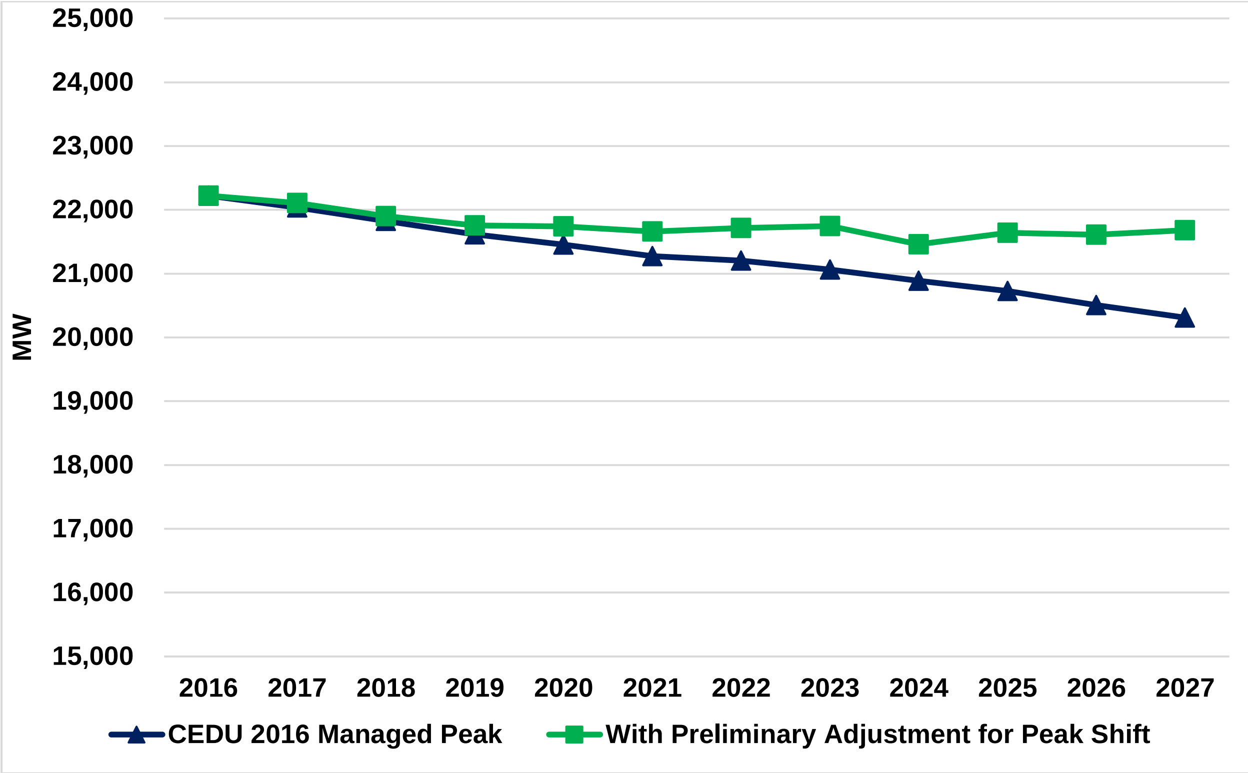
Source: Demand Analysis Office, California Energy Commission, 2016

Table 30: CEDU 2016 Managed Peak, Preliminary Peak-Shift Adjustment, and Preliminary Adjusted Managed Peak for the SCE Planning Area (MW)

	CEDU 2016 **Managed Peak**	**Preliminary Peak-Shift Adjustment**	**Preliminary Adjusted Managed Peak**
2016	22,224	--	22,224
2017	22,037	70	22,107
2018	21,826	77	21,902
2019	21,616	138	21,754
2020	21,457	284	21,741
2021	21,276	385	21,660
2022	21,204	513	21,716
2023	21,062	683	21,745
2024	20,885	575	21,460
2025	20,725	914	21,639
2026	20,507	1,102	21,609
2027	20,310	1,371	21,681

Source: Demand Analysis Office, California Energy Commission, 2016

Figure 7: *CEDU 2016* Managed Peak Forecast and Managed Forecast with Preliminary Adjustment for Peak Shift, SCE Planning Area



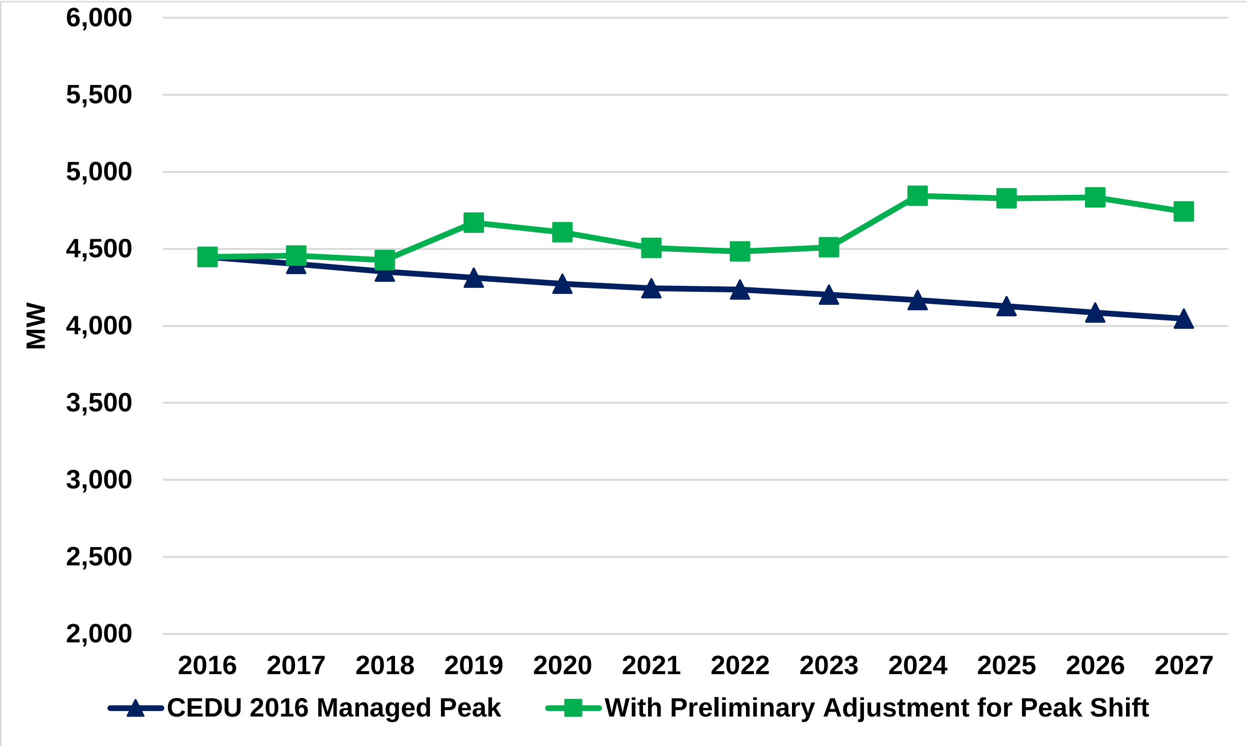
Source: Demand Analysis Office, California Energy Commission, 2016

Table 31: CEDU 2016 Managed Peak, Preliminary Peak-Shift Adjustment, and Preliminary Adjusted Managed Peak for the SDG&E Planning Area (MW)

	CEDU 2016 **Managed Peak**	**Preliminary Peak-Shift Adjustment**	**Preliminary Adjusted Managed Peak**
2016	4,448	--	4,448
2017	4,402	55	4,456
2018	4,353	74	4,427
2019	4,314	356	4,670
2020	4,274	333	4,607
2021	4,243	263	4,507
2022	4,237	246	4,483
2023	4,202	308	4,511
2024	4,167	677	4,844
2025	4,127	699	4,827
2026	4,086	748	4,834
2027	4,048	695	4,743

Source: Demand Analysis Office, California Energy Commission, 2016

Figure 8: *CEDU 2016* Managed Peak Forecast and Managed Forecast with Preliminary Adjustment for Peak Shift, SDG&E Planning Area



Source: Demand Analysis Office, California Energy Commission, 2016

Final Peak-Shift Adjustment

As shown in **Figure 6**, **Figure 7**, and **Figure 8**, there is a clear upward trend in the impacts of peak shift over the forecast period for each IOU. However, year-to-year changes can be abrupt. This reflects the particular assumptions made in developing the "average year" hourly temperatures that determine projected weather-normalized end-use loads. Other methods could certainly have been used to simulate an average weather future, which would likely have yielded a similar upward trend but different year-to-year changes in peak-shift adjustments.[40] Therefore, staff believes that any peak-shift adjustment for individual years for the scenario should be applied based on the upward trend, as calculated using a linear regression with estimated peak-shift adjustments specified as a function of time. The resulting trended adjustments are shown in **Table 32** and **Figure 9** for PG&E, **Table 33** and **Figure 10** for SCE, and **Table 34** and **Figure 11** for SDG&E, referred to as *final* adjustments for this scenario.

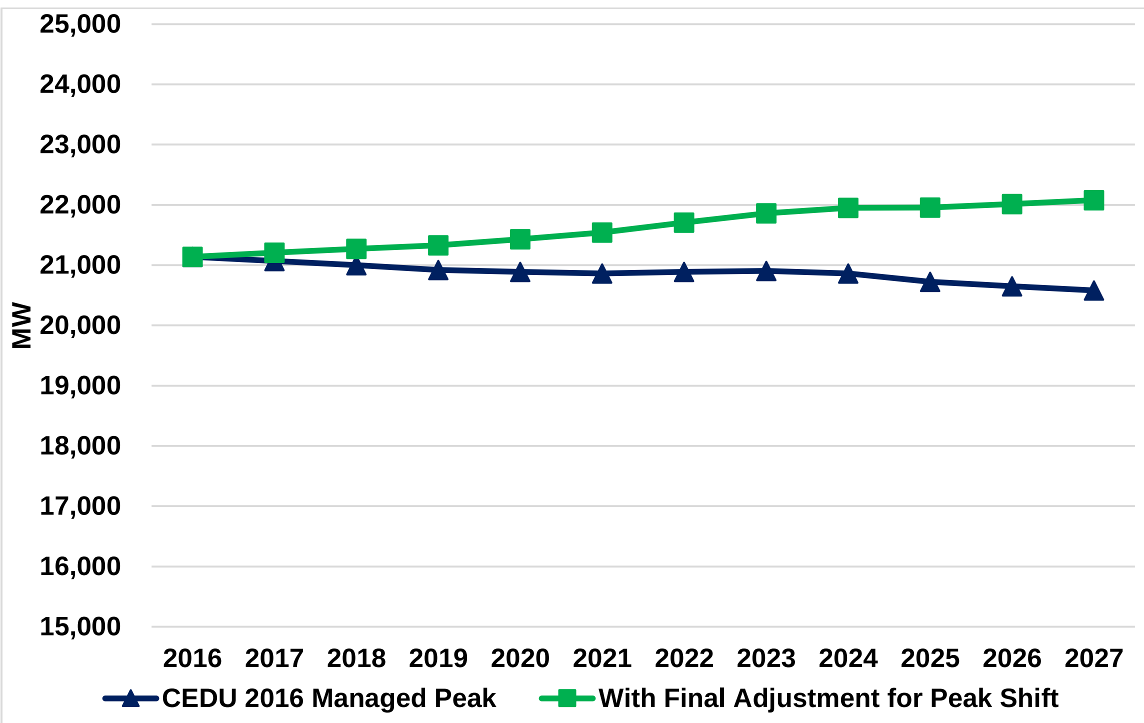
40 For the hourly load forecasting models being developing for the *2017 IEPR* forecast and beyond, staff is planning on simulating multiple weather/temperature futures in order to develop a distribution for hourly loads (and associated peak-shift) rather than one discrete outcome.

Table 32: *CEDU 2016* Managed Peak, Final Peak-Shift Adjustment, and Final Adjusted Managed Peak for the PG&E Planning Area (MW)

	CEDU 2016 Managed Peak	Final Peak-Shift Adjustment	Final Adjusted Managed Peak
2016	21,141	--	21,141
2017	21,071	136	21,207
2018	21,000	273	21,273
2019	20,920	409	21,329
2020	20,887	545	21,432
2021	20,861	682	21,542
2022	20,887	818	21,705
2023	20,905	955	21,860
2024	20,862	1,091	21,953
2025	20,727	1,227	21,954
2026	20,650	1,364	22,013
2027	20,579	1,500	22,079

Source: Demand Analysis Office, California Energy Commission, 2016

Figure 9: *CEDU 2016* Managed Peak Forecast and Managed Forecast with Final Adjustment for Peak-Shift, PG&E Planning Area



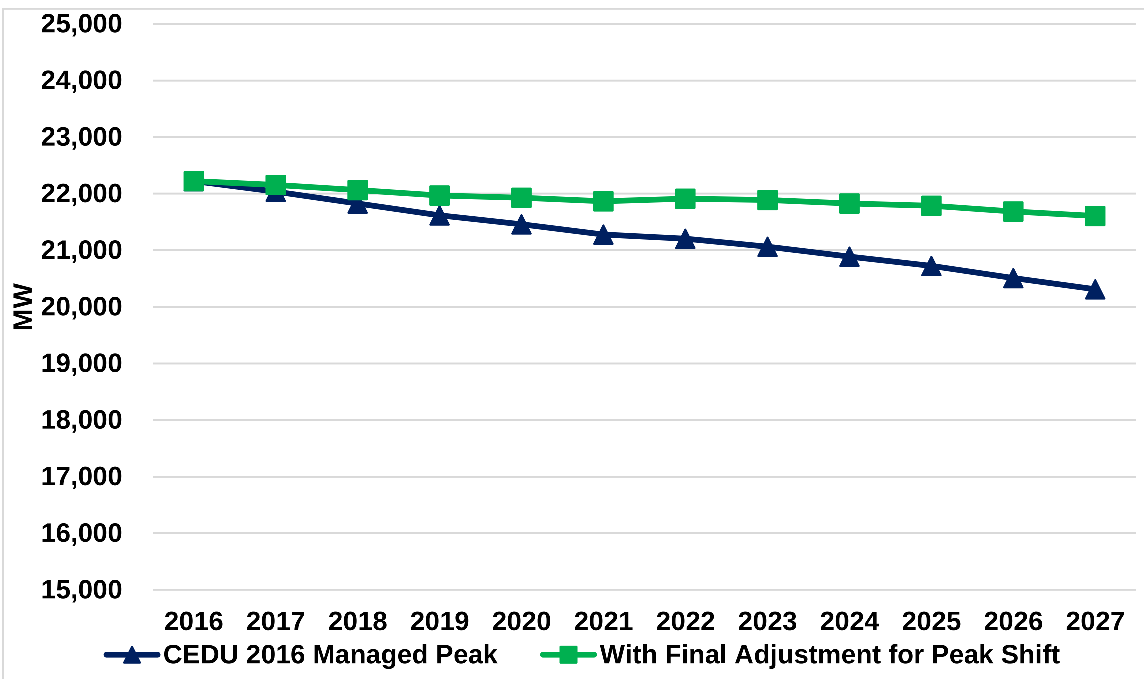
Source: Demand Analysis Office, California Energy Commission, 2016

Table 33: *CEDU 2016* Managed Peak, Final Peak-Shift Adjustment, and Final Adjusted Managed Peak for the SCE Planning Area (MW)

	CEDU 2016 Managed Peak	Final Peak-Shift Adjustment	Final Adjusted Managed Peak
2016	22,224	--	22,224
2017	22,037	118	22,155
2018	21,826	236	22,062
2019	21,616	354	21,970
2020	21,457	472	21,929
2021	21,276	590	21,865
2022	21,204	708	21,912
2023	21,062	826	21,888
2024	20,885	944	21,829
2025	20,725	1,062	21,787
2026	20,507	1,180	21,687
2027	20,310	1,298	21,607

Source: Demand Analysis Office, California Energy Commission, 2016

Figure 10: *CEDU 2016* Managed Peak Forecast and Managed Forecast with Final Adjustment for Peak-Shift, SCE Planning Area



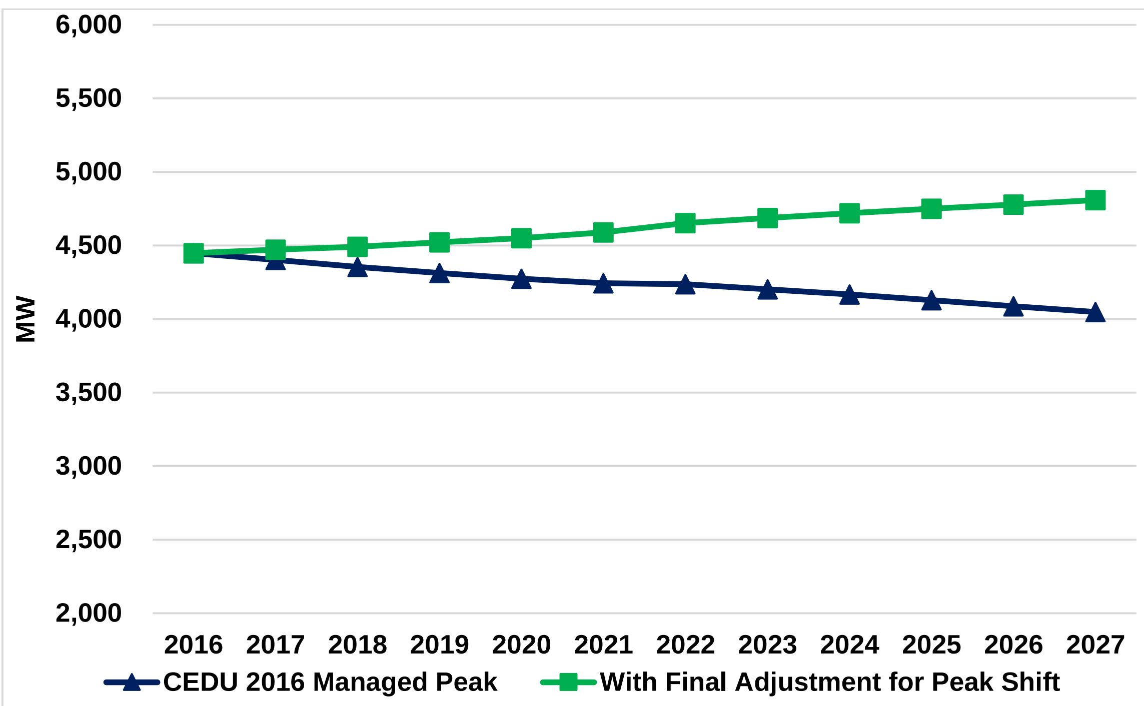
Source: Demand Analysis Office, California Energy Commission, 2016

Table 34: *CEDU 2016* Managed Peak, Final Peak-Shift Adjustment, and Final Adjusted Managed Peak for the SDG&E Planning Area (MW)

	***CEDU 2016* Managed Peak**	**Final Peak-Shift Adjustment**	**Final Adjusted Managed Peak**
2016	4,448	--	4,448
2017	4,402	69	4,471
2018	4,353	138	4,491
2019	4,314	207	4,521
2020	4,274	277	4,550
2021	4,243	346	4,589
2022	4,237	415	4,651
2023	4,202	484	4,686
2024	4,167	553	4,720
2025	4,127	622	4,750
2026	4,086	691	4,777
2027	4,048	760	4,808

Source: Demand Analysis Office, California Energy Commission, 2016

Figure 11: *CEDU 2016* Managed Peak Forecast and Managed Forecast with Final Adjustment for Peak-Shift, SDG&E Planning Area



Source: Demand Analysis Office, California Energy Commission, 2016

ACRONYMS

Acronym	**Definition**
AAEE	Additional achievable energy efficiency
California ISO	California Independent System Operator
CED	*California Energy Demand*
CED 2015	*California Energy Demand 2016 – 2026 Final Forecast*
CEDU 2016	*California Energy Demand Updated Forecast, 2017-2027*
CPUC	California Public Utilities Commission
DOF	California Department of Finance
Energy Commission	California Energy Commission
EV	Electric vehicle
GW	Gigawatt
GWh	Gigawatt-hour
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LSE	Load-serving entity
LTPP	Long-Term Procurement Plan
Moody's	Moody's Analytics
MW	Megawatt
NCNC	Northern California Non-California ISO
PG&E	Pacific Gas and Electric Company
POU	Publicly owned utility
PV	Photovoltaic
QFER	Quarterly Fuel Energy Report
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SMUD	Sacramento Municipal Utility District
TAC	Transmission access charge
TOU	Time-of-use
TPP	Transmission Planning Process

APPENDIX A: Regression Results

This appendix provides estimation results for the econometric models used in the analysis for *CEDU 2016*.

Table A-1: Residential Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Per capita income (2009$)	0.3620	0.0468	7.73
Residential Electricity Rate (2015¢/kWh)	-0.0845	0.0409	-2.07
Number of Cooling Degree Days (65º)	0.0620	0.0169	3.68
Number of Heating Degree Days (65º)	0.0541	0.0227	2.39
Dummy: 2001	-0.0605	0.0160	-3.78
Dummy: 2002	-0.0300	0.0161	-1.86
Constant: PG&E	4.3565	0.5775	7.54
Constant: SCE	4.3600	0.5726	7.61
Constant: SDG&E	4.2659	0.5734	7.44
Constant: NCNC	4.7098	0.5697	8.27
Constant: LADWP	4.1833	0.5697	7.34
Constant: Burbank/Glendale	4.3007	0.5730	7.51
Constant: Imperial Irrigation District	4.9301	0.5621	8.77
Trend Variables			
Time: PG&E	-0.0028	0.0017	-1.62
Time: NCNC	-0.0025	0.0010	-2.42
Time: LADWP	0.0055	0.0024	2.33
Time: Imperial Irrigation District	0.0198	0.0081	2.46
Time Squared: Imperial Irrigation District	-0.0007	0.0003	-2.32
Adjusted for autocorrelation and cross-sectional correlation. R-squared = .99 Dependent variable = natural log of electricity consumption per household by planning area, 1990-2015 All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2016.

Table A-2: Commercial Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Commercial Employment	0.8072	0.1157	6.98
Number of Cooling Degree Days (65º)	0.0884	0.0253	3.49
Constant: PG&E	2.9506	0.9574	3.08
Constant: SCE	2.8564	0.9508	3.00
Constant: SDG&E	2.6058	0.7966	3.27
Constant: NCNC	2.7303	0.7686	3.55
Constant: LADWP	2.8348	0.8449	3.36
Constant: Burbank/Glendale	2.5050	0.5528	4.53
Constant: Imperial Irrigation District	2.4703	0.4866	5.08
Trend Variables			
Time: PG&E	0.0051	0.0028	1.81
Time: SCE	0.0198	0.0048	4.10
Time Squared: SCE	-0.0005	0.0001	-3.29
Time: SDG&E	0.0069	0.0037	1.87
Time: Burbank/Glendale	0.0328	0.0057	5.81
Time Squared: Burbank/Glendale	-0.0011	0.0002	-5.73
Time: Imperial Irrigation District	0.0265	0.0100	2.65
Time Squared: Imperial Irrigation District	-0.0009	0.0003	-2.80
Adjusted for autocorrelation and cross-sectional correlation. R-squared = .99 Dependent variable = natural log of commercial consumption by planning area, 1990-2015. All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2016.

Table A-3: Manufacturing Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Manufacturing Output (million 2009$)	0.4884	0.0588	8.31
Industrial Electricity Rate (2015¢/kWh)	-0.0410	0.0702	-0.58
Constant: PG&E	5.0446	0.6374	7.91
Constant: SCE	4.9339	0.6457	7.64
Constant: SDG&E	3.4153	0.5334	6.40
Constant: NCNC	3.6106	0.5205	6.94
Constant: LADWP	3.8239	0.5927	6.45
Constant: Burbank/Glendale	2.7067	0.4520	5.99
Constant: Imperial Irrigation District	1.6844	0.4268	3.95
Trend Variables			
Time: PG&E	-0.0378	0.0070	-5.43
Time: SCE	-0.0268	0.0039	-6.88
Time: SDG&E	-0.0375	0.0042	-8.92
Time: LADWP	-0.0407	0.0083	-4.93
Time Squared: LADWP	0.0008	0.0003	2.77
Time: Burbank/Glendale	-0.1232	0.0128	-9.63
Time Squared: Burbank/Glendale	0.0024	0.0004	5.38
Adjusted for autocorrelation and cross-sectional correlation. R-squared = .99 Dependent variable = natural log of industrial consumption by planning area, 1990-2015. All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2016.

Table A-4: Resource Extraction and Construction Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Output, Resource Extraction (million 2009$)	0.0803	0.0389	2.06
Employment in Construction (thousands)	0.2715	0.0639	4.25
Percent Employment Resource Extraction	2.2024	1.0212	2.16
Industrial Electricity Rate (2015 cents/kWh)	-0.1049	0.0864	-1.21
Dummy: 1997 SDG&E	-1.0615	0.0751	-14.13
Constant: PG&E	5.9846	0.5470	10.94
Constant: SCE	6.1111	0.5292	11.55
Constant: SDG&E	4.5892	0.3704	12.39
Constant: NCNC	3.6112	0.3922	9.21
Constant: LADWP	3.9938	0.4502	8.87
Constant: Burbank/Glendale	2.8159	0.3256	8.65
Constant: Imperial Irrigation District	2.4085	0.3784	6.36
Trend Variables			
Time: PG&E	-0.0342	0.0130	-2.63
Time squared: PG&E	0.0018	0.0005	4.01
Time: SCE	-0.0244	0.0127	-1.92
Time squared: SCE	0.0010	0.0004	2.19
Time: SDG&E	-0.0639	0.0174	-3.67
Time squared: SDG&E	0.0013	0.0006	2.19
Time: NCNC	0.0190	0.0040	4.75
Time: Burbank/Glendale	0.0403	0.0132	3.05
Time Squared: Burbank/Glendale	-0.0017	0.0005	-3.68
Time: Imperial Irrigation District	0.0373	0.0092	4.05
Adjusted for autocorrelation and cross-sectional correlation. R-squared = .99 Dependent variable = natural log of construction & resource extraction consumption by planning area 1990-2015. All variables in logged form except time and percentage employment resource extraction.			

Source: California Energy Commission, Demand Analysis Office, 2016.

Table A-5: Agriculture and Water Pumping Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Agricultural Electricity Rate (2015 cents/kWh)	-0.3040	0.1728	-1.76
Precipitation (annual inches)	-0.0407	0.0221	-1.84
Constant: PG&E	7.2238	0.4602	15.70
Constant: SCE	6.8533	0.4638	14.78
Constant: SDG&E	5.0363	0.4852	10.38
Constant: NCNC	7.3594	0.4856	15.16
Constant: LADWP	5.1872	0.6055	8.57
Constant: Burbank/Glendale	4.3153	0.5292	8.15
Constant: Imperial Irrigation District	7.6579	0.4802	15.95
Trend Variables			
Time: PG&E	-0.0352	0.0110	-3.20
Time Squared: PG&E	0.0016	0.0004	3.87
Time: SDG&E	0.0223	0.0120	1.86
Time: NCNC	-0.0308	0.0136	-2.27
Time: LADWP	-0.0597	0.0264	-2.26
Time: Imperial Irrigation District	-0.0119	0.0048	-2.46

Adjusted for autocorrelation and cross-sectional correlation.

R-squared = .99

Dependent variable = natural log of agriculture and water pumping electricity consumption per capita by planning area 1990-2015.

All variables in logged form except time.

Source: California Energy Commission, Demand Analysis Office, 2016.

Table A-6: Transportation, Communications, and Utilities (TCU) Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Per capita income (2015$)	0.3333	0.0138	24.07
Dummy: Burbank/Glendale 2008	1.2042	0.1337	9.01
Constant: PG&E	4.9587	0.1568	31.63
Constant: SCE	4.7964	0.1461	32.83
Constant: SDG&E	3.7297	0.1508	24.73
Constant: NCNC	3.1180	0.1781	17.50
Constant: LADWP	3.6151	0.3014	11.99
Constant: Imperial Irrigation District	2.2607	0.2665	8.48
Trend Variables			
Time: SCE	0.0076	0.0017	4.38
Time: SDG&E	0.0085	0.0024	3.51
Time: Burbank/Glendale	0.0195	0.0106	1.85
Time: Imperial Irrigation District	-0.0263	0.0139	-1.89
Adjusted for autocorrelation and cross-sectional correlation. R-squared = .99 Dependent variable = natural log of TCU electricity consumption per capita by planning area 1990-2015. All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2016.

Table A-7: Street Lighting Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Population	1.6673	0.2806	5.94
Constant: PG&E	-9.2900	2.6034	-3.57
Constant: SCE	-8.9553	2.6277	-3.41
Constant: SDG&E	-8.9181	2.2577	-3.95
Constant: NCNC	-7.6567	2.0527	-3.73
Constant: LADWP	-7.5786	2.3684	-3.20
Constant: Burbank/Glendale	-6.4099	1.5697	-4.08
Constant: Imperial Irrigation District	-7.4923	1.6115	-4.65
Trend Variables			
Time PG&E	-0.0157	0.0036	-4.43
Time: SCE	-0.0594	0.0100	-5.95
Time Squared: SCE	0.0013	0.0003	3.84
Time: NCNC	-0.0188	0.0054	-3.48
Time LADWP	-0.0429	0.0159	-2.70
Time: Burbank/Glendale	-0.0422	0.0159	-2.65
Time Squared: Burbank/Glendale	0.0017	0.0006	3.07
Adjusted for autocorrelation and cross-sectional correlation. R-squared = .99 Dependent variable = natural log of street lighting electricity consumption by planning area 1990-2015 All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2016.

Table A-8: Peak Demand Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Unemployment Rate	-0.0033	0.0017	-1.86
Residential Electricity Rate	-0.0904	0.0389	-2.33
Annual Max *Average631*	0.9126	0.1069	8.54
Residential Consumption per Capita	0.2407	0.0610	3.95
Dummy: 2001	-0.0572	0.0174	-3.28
Constant: PG&E	-5.2579	0.6133	-8.57
Constant: SCE	-5.2201	0.6121	-8.53
Constant: SDG&E	-5.5432	0.6068	-9.14
Constant: NCNC	-4.9745	0.6281	-7.92
Constant: LADWP	-5.2686	0.6062	-8.69
Constant: Burbank/Glendale	-5.0639	0.6140	-8.25
Constant: Imperial Irrigation District	-5.0261	0.6429	-7.82
Trend Variables			
Time: PG&E	0.0025	0.0007	3.60
Time: SDG&E	0.0082	0.0014	6.01
Time: Burbank/Glendale	0.0033	0.0014	2.38
Adjusted for autocorrelation and cross-sectional correlation. R-squared = .99 Dependent variable = natural log of annual peak per capita by planning area, 1990-2015. All variables in logged form except time and unemployment rate.			

Source: California Energy Commission, Demand Analysis Office, 2016.