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California Energy Commission

STAFF REPORT

California Energy Demand 2016-2026, Revised Electricity Forecast

Volume 1: Statewide Electricity Demand and Energy Efficiency

California Energy Commission

Edmund G. Brown Jr., Governor

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California Energy Commission

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ABSTRACT

The *California Energy Demand 2016-2026, Revised Electricity Forecast* describes the California Energy Commission's revised 10-year forecasts for electricity consumption, retail sales, and peak demand for each of five major electricity planning areas and for the state. This forecast supports the analysis and recommendations of the *2014 Integrated Energy Policy Report Update*. The forecast includes three demand 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 and climate change impacts and relatively low electricity rates and self-generation impacts. The low energy demand case includes lower economic/demographic growth, higher assumed rates, and higher self-generation impacts. The mid case uses input assumptions at levels between the high and low cases. In addition, this forecast incorporates estimates for additional achievable energy efficiency and provides adjusted, or managed, forecasts designed for resource planning. Forecasts are provided at both the planning area and climate zone level.

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

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EXECUTIVE SUMMARY

Introduction

This report describes 10-year forecasts of electricity consumption and peak electricity demand for California and for each major utility planning area within the state for the period 2016-2026. The end-user natural gas forecast developed in conjunction with electricity will be detailed in the California Energy Commission's forthcoming *Natural Gas Outlook*. The *California Energy Demand 2016-2026, Revised Electricity Forecast* (*CED 2015 Revised*) supports the analysis and recommendations of the *2014 Integrated Energy Policy Report Update*, including electricity system assessments and analysis of progress toward increased energy efficiency and distributed generation.

CED 2015 Revised includes three 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 relatively low self-generation and climate change impacts. The low energy demand case includes lower economic/demographic growth, higher assumed rates, and higher self-generation impacts. The mid case uses input assumptions at levels between the high and low cases.

Staff also developed estimates of additional achievable energy efficiency impacts for the investor-owned utilities and the largest publicly owned utilities that are incremental to (do not overlap with) committed efficiency savings included in the *CED 2015 Revised* baseline cases. Forecasts adjusted to reflect these additional savings are presented in this report.

Baseline Forecast Results

A comparison of the *CED 2015 Revised* baseline electricity forecast with the *California Energy Demand Updated Forecast, 2015-2025* (*CEDU 2014*) mid demand case for selected years is shown in **Table ES-1**. As the table shows, the consumption forecast for 2014 from *CEDU 2014* was higher than actual historical consumption. (*CEDU 2014* incorporated historical consumption data through 2013.) Consumption in the *CED 2015 Revised* mid demand case grows at a slower rate through 2025 as compared to the *CEDU 2014* mid case as a result of additional appliance standards and a reassessment of Title 24 energy efficiency standards for existing buildings.

CED 2015 Revised statewide noncoincident peak demand (the sum of planning area peaks, which may occur at different hours), adjusted to account for atypical weather, grows at a slower rate from 2015-2025 in the mid case compared to *CEDU 2014*, reflecting the drop in consumption as well as a higher self-generation forecast, particularly for photovoltaics. All three *CED 2015 Revised* cases are significantly lower than the *CEDU 2014* mid case throughout the forecast period.

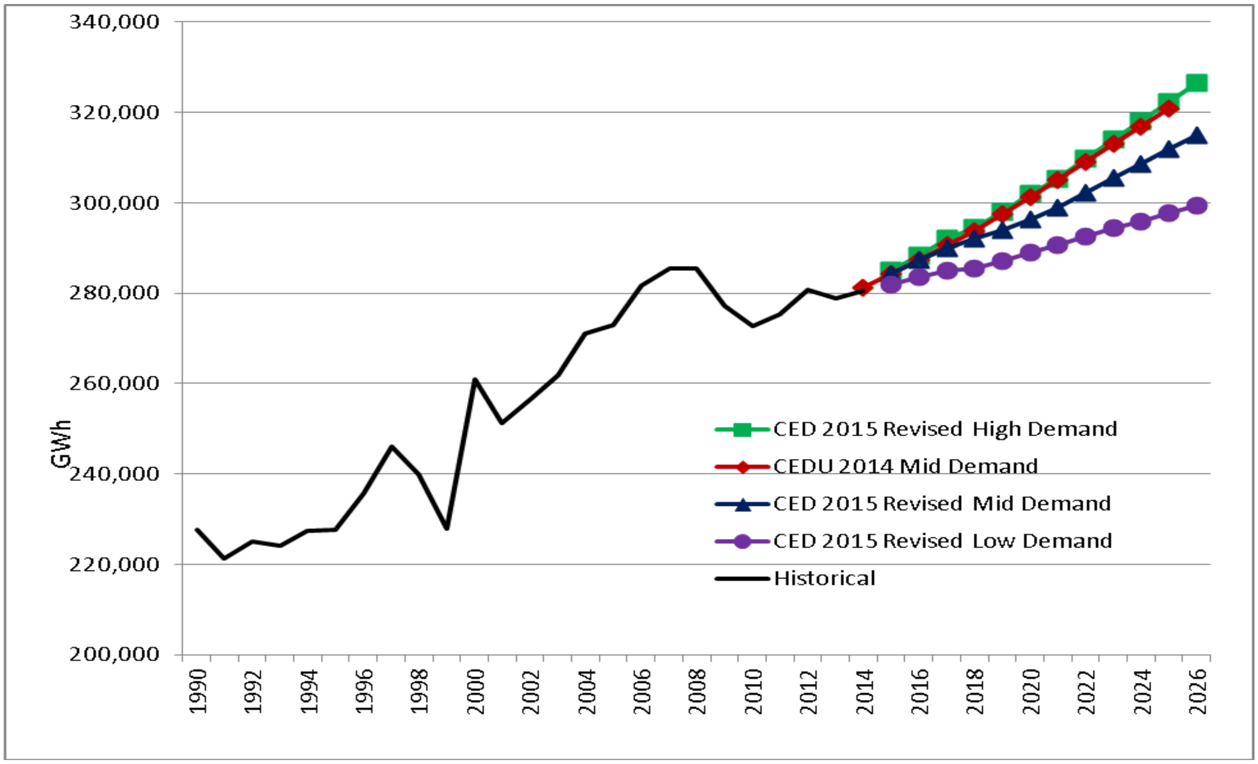
Table ES-1: Comparison of *CED 2015 Revised* and *CEDU 2014* Mid Case Demand Baseline Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	***CEDU 2014* Mid Energy Demand**	***CED 2015 Revised* High Energy Demand**	***CED 2015 Revised* Mid Energy Demand**	***CED 2015 Revised* Low Energy Demand**
1990	227,576	227,606	227,606	227,606
2000	260,399	261,037	261,037	261,037
2014	281,195	280,536	280,536	280,536
2020	301,290	301,884	296,244	289,085
2025	320,862	322,266	311,848	297,618
2026	--	326,491	314,970	299,372
	Average Annual Growth Rates			
1990-2000	1.36%	1.38%	1.38%	1.38%
2000-2014	0.55%	0.52%	0.52%	0.52%
2014-2020	1.16%	1.23%	0.91%	0.50%
2014-2025	1.21%	1.27%	0.97%	0.54%
2014-2026	--	1.27%	0.97%	0.54%
Noncoincident Peak (MW)				
	***CEDU 2014* Mid Energy Demand**	***CED 2015 Revised* High Energy Demand**	***CED 2015 Revised* Mid Energy Demand**	***CED 2015 Revised* Low Energy Demand**
1990	47,543	47,123	47,123	47,123
2000	53,702	53,529	53,529	53,529
2015*	63,577	60,968	60,968	60,968
2020	67,373	63,658	62,414	60,560
2025	70,763	67,167	63,848	59,293
2026		67,830	64,007	58,835
	Average Annual Growth Rates			
1990-2000	1.23%	1.28%	1.28%	1.28%
2000-2015	1.13%	0.87%	0.87%	0.87%
2015-2020	1.17%	0.87%	0.47%	-0.13%
2015-2025	1.08%	0.97%	0.46%	-0.28%
2015-2026	--	0.97%	0.44%	-0.32%
Actual historical values are shaded.				
*Weather normalized: *CED 2015* uses a weather-normalized peak value derived from the actual 2015 peak for calculating growth rates during the forecast period.				

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

Projected electricity consumption for the three *CED 2015 Revised* baseline cases and the *CEDU 2014* mid demand forecast is shown in **Figure ES-1**. By 2025, consumption in the new mid case is projected to be 2.8 percent lower than the *CEDU 2014* mid case, around 9,000 gigawatt-hours. Annual growth rates from 2014-2025 for *CED 2015 Revised* average 1.27 percent, 0.97 percent, and 0.54 percent in the high, mid and low cases, respectively, compared to 1.21 percent in the *CEDU 2014* mid case.

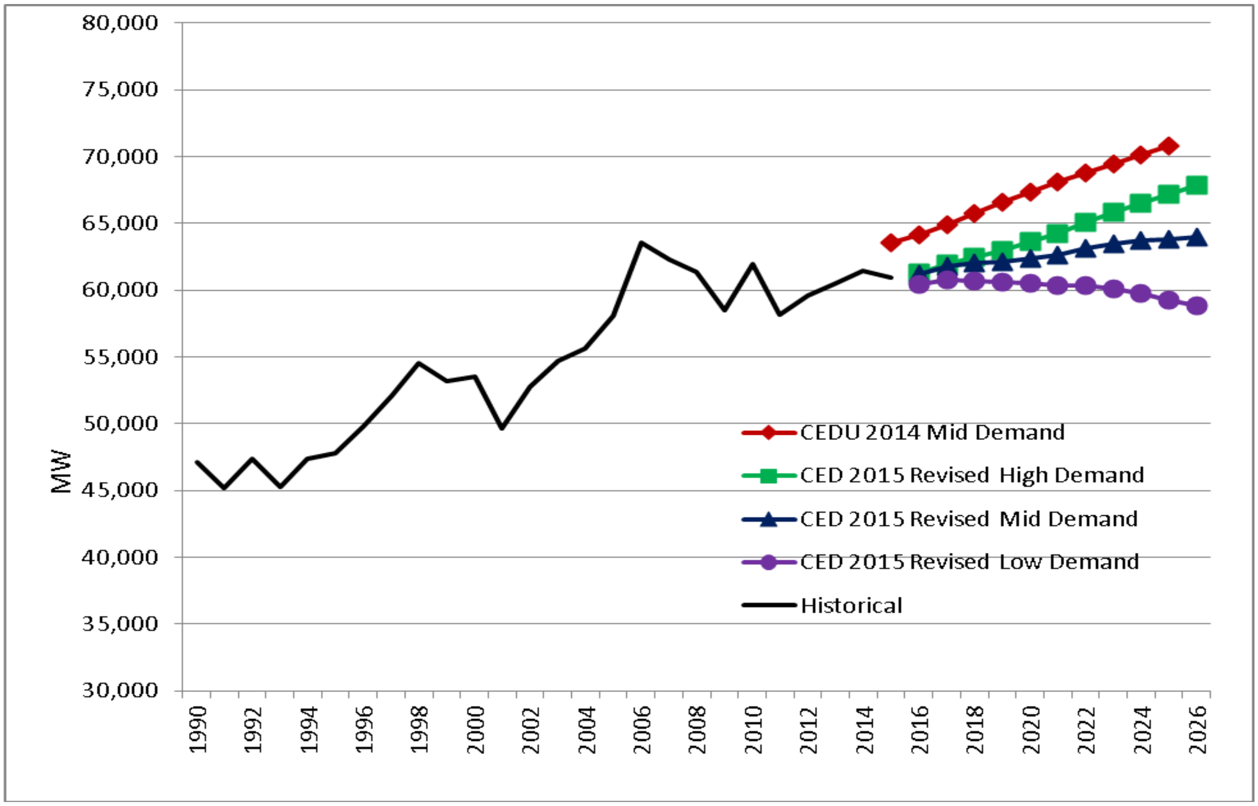
Figure ES-1: Statewide Baseline Annual Electricity Consumption



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

Projected *CED 2015 Revised* baseline noncoincident peak demand, adjusted for atypical weather, for the three baseline cases and the *CEDU 2014* mid demand peak forecast is shown in **Figure ES-2.** By 2025, statewide peak demand in the *CED 2015 Revised* mid case is projected to be almost 10 percent lower than in the *CEDU 2014* mid case. Annual growth rates from 2015-2025 for *CED 2015 Revised* average 0.97 percent, 0.46 percent, and -0.28 percent in the high, mid, and low cases, respectively, compared to 1.08 percent in the *CEDU 2014* mid case.

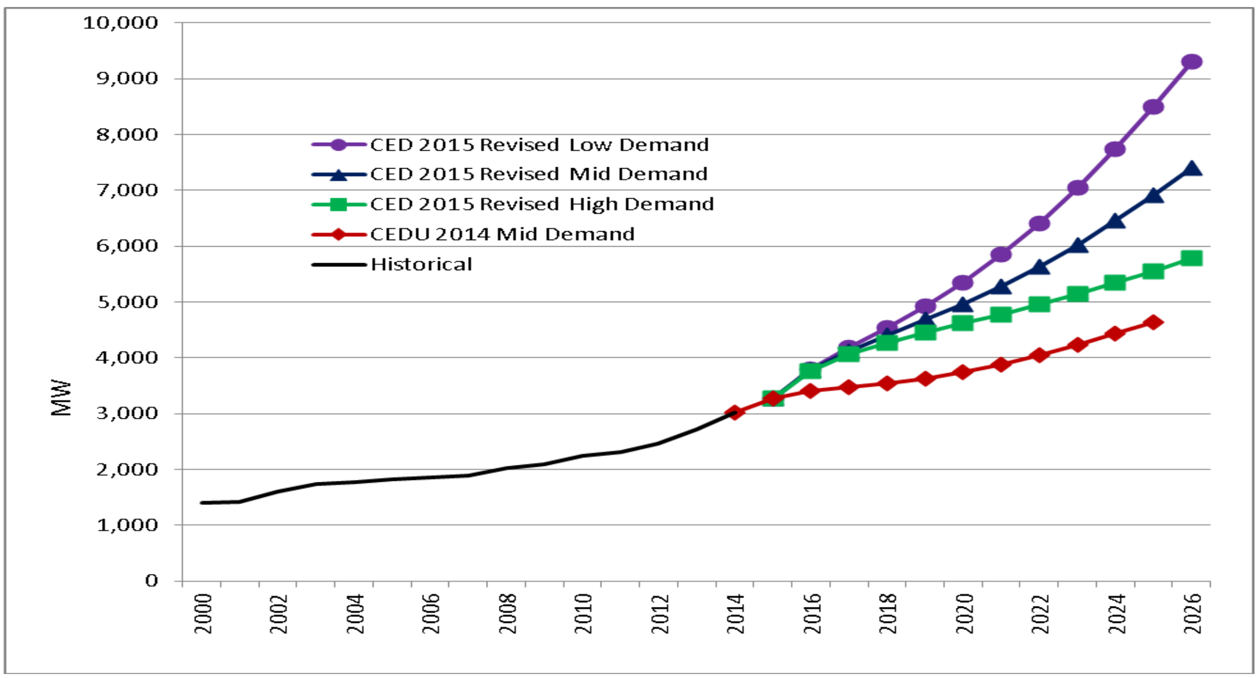
Figure ES-2: Statewide Baseline Annual Noncoincident Peak Demand



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

Historical and projected peak reduction impacts of self-generation for the three *CED 2015 Revised* demand cases and the *CEDU 2014* mid case are shown in **Figure ES-3**. Self-generation is projected to reduce peak load by more than 6,900 megawatts in the new mid case by 2025, an increase of more than 2,000 megawatts compared to *CEDU 2014*. Residential photovoltaic is a key factor in this increase: by 2026, residential photovoltaic peak impacts reach almost 3,000 megawatts in the *CED 2015 Revised* mid case, corresponding to more than 7,700 megawatts of installed capacity.

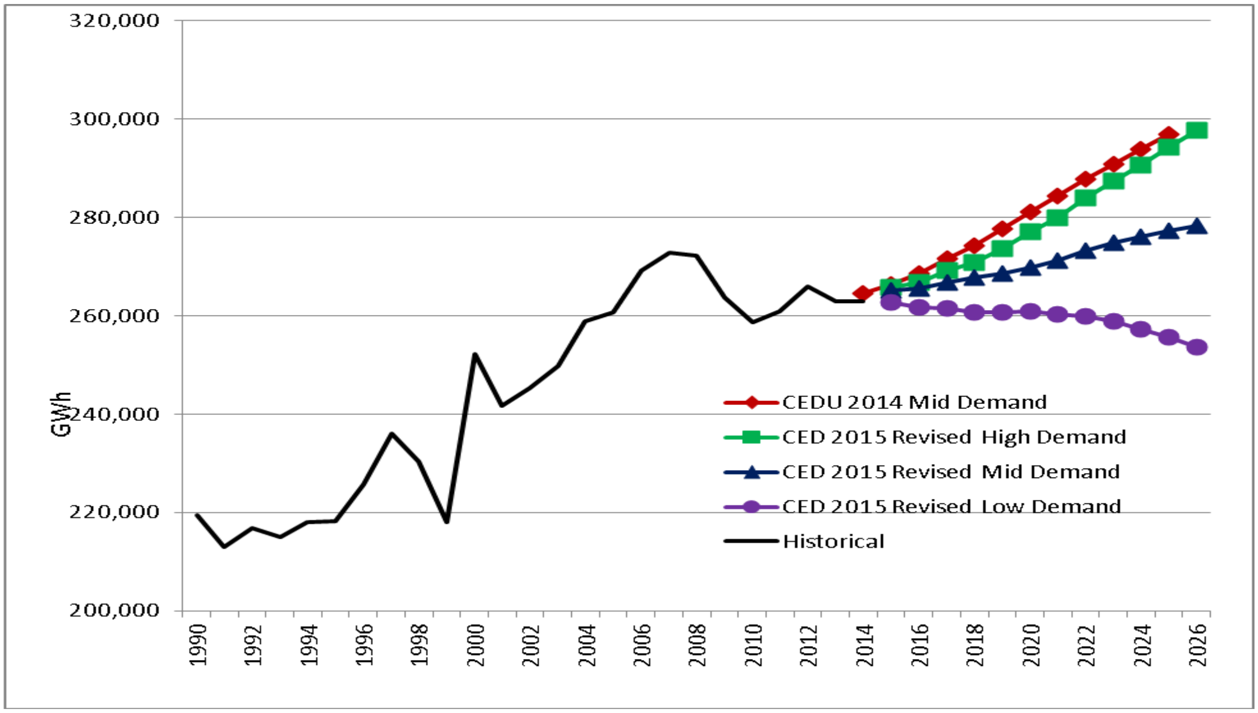
Figure ES-3: Statewide Self-Generation Peak Reduction Impact



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

The higher forecast for self-generation adoption also has a significant impact on projected baseline statewide retail electricity sales, as shown in **Figure ES-4**. All three new forecast cases are lower than the *CEDU 2014* mid case throughout the forecast period. By 2025, sales in the *CED 2015 Revised* mid case are projected to be almost 20,000 gigawatt-hours lower than in the *CEDU 2014* mid case, around 6.6 percent. Annual growth from 2014-2025 for *CED 2015 Revised* averages 1.00 percent, 0.48 percent, and -0.26 percent in the high, mid and low cases, respectively, compared to 1.05 percent in the *CEDU 2014* mid case.

Figure ES-4: Statewide Baseline Retail Electricity Sales



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

Additional Achievable Energy Efficiency

CED 2015 Revised includes estimates of additional achievable energy efficiency savings for the three investor-owned utility service territories and the two largest publicly owned utilities. These savings are not yet considered committed, or firm, but are deemed reasonably likely to occur and include impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2015. Five energy savings scenarios were developed for the investor-owned utilities and three for the publicly owned utilities. This report describes the impact of additional achievable energy and peak demand savings incorporated in adjusted (relative to the baseline), or managed, forecasts for these service territories. For the investor-owned utilities combined, additional achievable energy efficiency energy savings range from 13,500 gigawatt-hours to 21,500 gigawatt-hours in 2026. Peak demand savings range from 3,300 megawatts to 5,300 megawatts. For the publicly owned utilities combined, additional achievable energy efficiency energy impacts range from 2,900 gigawatt-hours to 3,600 gigawatt-hours and peak impacts from 750 megawatts to 950 megawatts in 2026.

Summary of Changes to Forecast

In an effort to make the demand forecast more useful to resource planners, *CED 2015 Revised* uses a revised geographic scheme for planning areas and climate zones, more closely based on California's balancing authority areas. *CED 2015 Revised* includes 20 climate zones, compared to 16 in previous forecasts. The new scheme is described in more detail later in this chapter; future forecasts may incorporate further refinements to geographic granularity.

CED 2015 Revised includes estimated efficiency impacts not included in *CEDU 2014*, from 2015 investor-owned utility programs and 2014 programs administered by publicly owned utilities, as well as from new federal and state appliance standards. Projected additional achievable energy efficiency impacts for the investor-owned utilities have been updated, based on the California Public Utilities Commission's *2015 California Energy Efficiency Potential and Goals Study*. This forecast also includes estimates of additional achievable energy efficiency savings for the two largest publicly owned utilities.

CED 2015 Revised incorporates new projections for electric vehicle fuel consumption, based on scenarios developed by the California Energy Commission's Transportation Energy Forecasting Unit. In addition, estimated impacts from additional transportation-related electrification are included. Staff's self-generation model was modified to incorporate residential load patterns and a tiered rate structure, which results in a significantly higher forecast for photovoltaic system adoption.

Unlike in previous forecasts, this report does not provide results for projected end-user natural gas demand. Instead, to avoid duplicating staff effort, end-user natural gas results will be combined with gas generation forecasts as part of the California Energy Commission's forthcoming *Natural Gas Outlook*, to be published by February 2016.

CHAPTER 1:
Statewide Baseline Forecast Results and Forecast Method

Introduction

This California Energy Commission staff report presents forecasts of electricity consumption and peak electricity demand for California and for each major utility planning area within the state for 2016-2026. The *California Energy Demand 2016-2026, Revised Electricity Forecast* (*CED 2015 Revised*) supports the analysis and recommendations of the *2014 Integrated Energy Policy Report Update*, including electricity system assessments and analysis of progress toward increased energy efficiency and distributed generation.

The Integrated Energy Policy Report (IEPR) Lead Commissioner conducted a workshop on December 17, 2015, to receive public comments on this forecast. After all comments have been received, subject to the direction of the IEPR Lead Commissioner, staff will prepare a final forecast that may contain minor revisions to *CED 2015 Revised* for possible adoption by the Energy Commission.

The final forecasts will be used in several applications, including the California Public Utilities Commission (CPUC) 2016 Long Term Procurement Plan proceeding. The CPUC has identified the IEPR process as "the appropriate venue for considering issues of load forecasting, resource assessment, and scenario analyses, to determine the appropriate level and ranges of resource needs for load serving entities in California."[1] The final forecasts will also be an input to California Independent System Operator (California ISO) controlled grid studies and other transmission planning studies and in electricity supply-demand (resource adequacy) assessments.

CED 2015 Revised includes three full 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 and climate change impacts, and relatively low electricity rates and self-generation impacts. The low energy demand case includes lower economic/demographic growth, higher assumed rates, and higher self-generation impacts. The mid case uses input assumptions at levels between the high and low cases. These forecasts are referred to as baseline cases, meaning they do not include additional achievable energy efficiency (AAEE) savings. This report also provides AAEE estimates for the investor-owned utilities (IOUs) and the two largest publicly owned utilities (POUs). AAEE estimates are designed as adjustments to the baseline cases to produce adjusted, or managed, forecasts for planning.

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

Details on input assumptions for these cases are provided later in this chapter. The forecast comparisons presented in this report show the three *CED 2015 Revised* baseline cases versus the mid case from the last adopted forecast, *California Energy Demand Updated Forecast, 2015-2025 (CEDU 2014)*, except where otherwise noted.

Structure of Report

Chapter 1 of Volume 1 begins by presenting changes to the forecast and the statewide baseline forecast results in comparison to *CEDU 2014*. This is followed by a description of the forecast method covering the geographic scheme, economic and demographic inputs, conservation/efficiency impacts, self-generation, electric vehicles, additional electrification, and climate change impacts. Chapter 2 of Volume 1 presents committed energy efficiency and conservation savings estimated for the forecast as well as estimates of AAEE savings, a discussion of the methods used to develop these estimates, and resulting adjusted, or managed, forecasts. The appendices of Volume 1 provide additional information about forecast performance, self-generation, regression results, and a special topic: energy use in the industrial sector. Volume 2 provides *CED 2015 Revised* electricity forecasts for the following planning areas: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Northern California Non-California ISO (NCNC), and Los Angeles Department of Water and Power (LADWP).

Summary of Changes to Forecast

CED 2015 Revised is based on historical electricity consumption and sales data through 2014 and peak demand data through 2015, adding one more historical year in each case compared to *CEDU 2014*. Economic and demographic drivers and electricity rate scenarios have been updated for this forecast.

In an effort to make the demand forecast more useful to resource planners, *CED 2015 Revised* uses a revised geographic scheme for planning areas and climate zones, more closely based on California's balancing authority areas.[2] *CED 2015 Revised* includes 20 climate zones, compared to 16 in previous forecasts. The new scheme is described in more detail later in this chapter, and future forecasts may incorporate further refinements to geographic granularity.

CED 2015 Revised includes estimated efficiency impacts not included in *CEDU 2014*, from 2015 IOU programs and 2014 programs administered by POUs, as well as from new federal and state appliance standards. Projected AAEE impacts for the IOUs have been updated, based on the CPUC's *2015 California Energy Efficiency Potential and Goals Study*.[3] This forecast also includes estimates of AAEE savings for the two largest POUs.

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

3 Information available at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm.

CED 2015 Revised incorporates new projections for electric vehicle (EV) fuel consumption, based on scenarios developed by the Energy Commission's Transportation Energy Forecasting Unit. In addition, estimated impacts from additional transportation-related electrification are included. Staff's self-generation model was modified to incorporate residential load patterns and a tiered rate structure, which results in a significantly higher forecast for photovoltaic (PV) system adoption.

Unlike in previous forecasts, this report does not provide results for projected end-user natural gas demand. Instead, to avoid duplicating staff effort, end-user natural gas results will be combined with gas generation forecasts as part of the Energy Commission's forthcoming *Natural Gas Outlook*.[4]

Changes From Preliminary to Revised Forecast

Staff prepared a preliminary version of this forecast (*CED 2015 Preliminary*),[5] presented in a workshop on July 7, 2015. The analysis for *CED 2015 Revised* reflects the following updates and changes:

- Updated economic/demographic projections based on forecasts by Moody's Analytics and IHS Global Insight for July 2015. (The preliminary forecast used projections from February 2015.)
- Revised electricity and natural gas rate forecasts.
- A new forecast for electric light-duty vehicles, developed by the Energy Commission's Transportation Energy Forecasting Unit.
- New projections for additional electrification, developed with the assistance of the Aspen Environmental Group.
- Incorporation of new state appliance standards adopted by the Energy Commission earlier in 2015 and recently adopted federal standards, which were included as part of AAEE savings in 2013.
- Reassessment of savings impacts generated by Title 24 standards for existing buildings.
- Updated cases for PV adoption, which incorporate a flatter rate structure (less tiers) for the IOUs.
- New AAEE scenarios for the IOUs as well as the two largest POUs.

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4 To be published by February 2016.

5 Kavalec, Chris and Asish Gautam, 2015. *California Energy Demand 2016-2026 Preliminary Forecast.* California Energy Commission, Electricity Assessments Division. Publication Number CEC-200-2015-003. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN205141_20150623T153206_CALIFORNIA_ENERGY_DEMAND_20162026_PRELIMINARY_ELECTRICITY_FOREC.pdf

Statewide Results

The *CED 2015 Revised* baseline electricity forecast for selected years (five-year increments starting in 2015 plus the final year of the forecast) is compared with the *CEDU 2014* mid demand case[6] in **Table 1**. *CED 2015 Revised* updates the last historical year to 2014 for consumption and sales and to 2015 for peak demand. As the table shows, the consumption forecast for 2014 from *CEDU 2014* is higher than actual. (*CEDU 2014* incorporated historical consumption data through 2013.) Consumption in the *CED 2015 Revised* mid demand case grows at a slower rate through 2025 compared to the *CEDU 2014* mid case as a result of additional appliance standards and a reassessment of Title 24 standards for existing buildings. *CED 2015 Revised* statewide noncoincident[7] weather-normalized[8] peak demand grows at a slower rate from 2015-2025 in the mid case compared to *CEDU 2014*, reflecting the drop in consumption as well as a lower starting point,[9] and a higher self-generation forecast, particularly for PV. In fact, all three *CED 2015 Revised* cases are significantly lower than the *CEDU 2014* mid case throughout the forecast period.

6 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.

7 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.

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

9 The lower starting point results from flat growth in actual peak demand over the last three years, which yields significantly lower weather-normalized peaks for the last historical year in *CED 2015 Revised*.

Table 1: Comparison of *CED 2015 Revised* and *CEDU 2014* Mid Case Demand Baseline Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	***CEDU 2014* Mid Energy Demand**	***CED 2015 Revised* High Energy Demand**	***CED 2015 Revised* Mid Energy Demand**	***CED 2015 Revised* Low Energy Demand**
1990	227,576	227,606	227,606	227,606
2000	260,399	261,037	261,037	261,037
2014	281,195	280,536	280,536	280,536
2020	301,290	301,884	296,244	289,085
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	Average Annual Growth Rates			
1990-2000	1.36%	1.38%	1.38%	1.38%
2000-2014	0.55%	0.52%	0.52%	0.52%
2014-2020	1.16%	1.23%	0.91%	0.50%
2014-2025	1.21%	1.27%	0.97%	0.54%
2014-2026	--	1.27%	0.97%	0.54%
Noncoincident Peak (MW)				
	***CEDU 2014* Mid Energy Demand**	***CED 2015 Revised* High Energy Demand**	***CED 2015 Revised* Mid Energy Demand**	***CED 2015 Revised* Low Energy Demand**
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2000	53,702	53,529	53,529	53,529
2015*	63,577	60,968	60,968	60,968
2020	67,373	63,658	62,414	60,560
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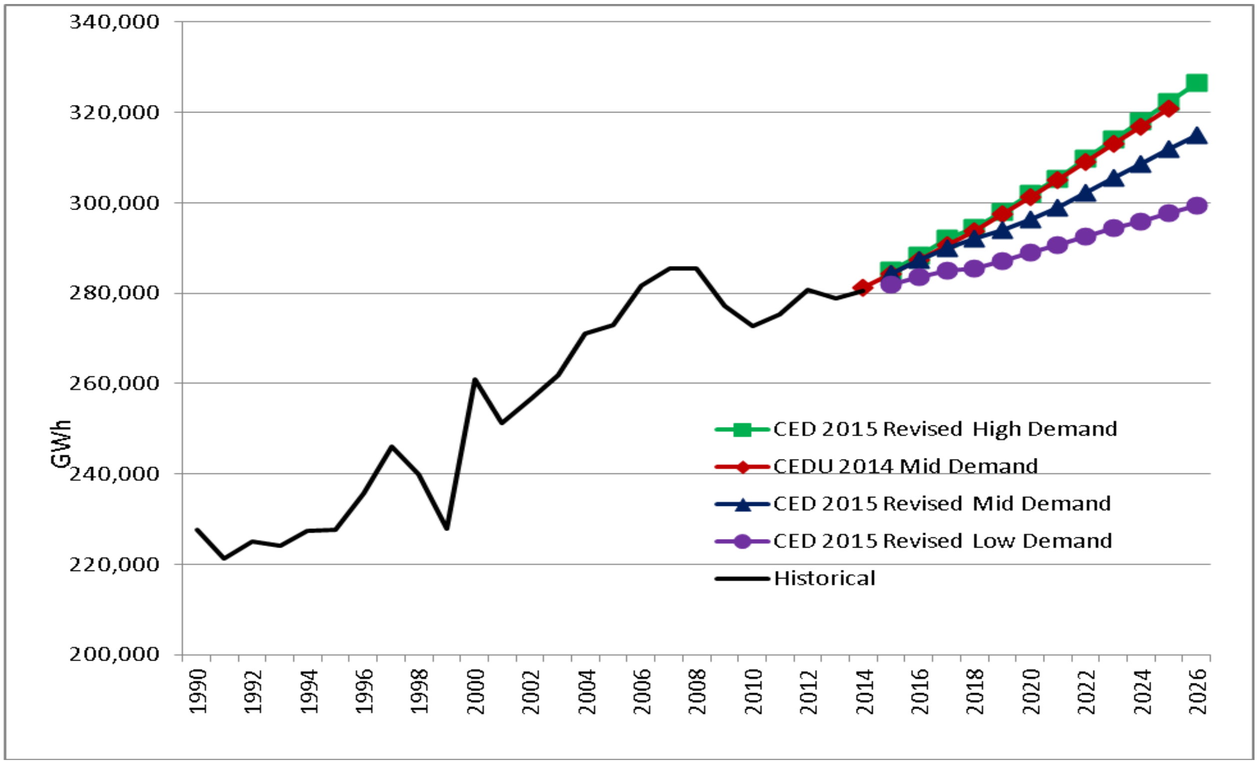
2026		67,830	64,007	58,835
	Average Annual Growth Rates			
1990-2000	1.23%	1.28%	1.28%	1.28%
2000-2015	1.13%	0.87%	0.87%	0.87%
2015-2020	1.17%	0.87%	0.47%	-0.13%
2015-2025	1.08%	0.97%	0.46%	-0.28%
2015-2026	--	0.97%	0.44%	-0.32%
Actual historical values are shaded.				
*Weather normalized: *CED 2015* uses a weather-normalized peak value derived from the actual 2015 peak for calculating growth rates during the forecast period.				

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

Projected electricity consumption for the three *CED 2015 Revised* baseline cases and the *CEDU 2014* mid demand forecast is shown in **Figure 1**. By 2025, consumption in the new mid case is projected to be 2.8 percent lower than the *CEDU 2014* mid case, around 9,000 gigawatt-hours (GWh). Annual growth rates from 2014-2025 for the *CED 2015 Revised* forecast average 1.27 percent, 0.97 percent, and 0.54 percent in the high, mid and low cases, respectively, compared to 1.21 percent in the *CEDU 2014* mid case.

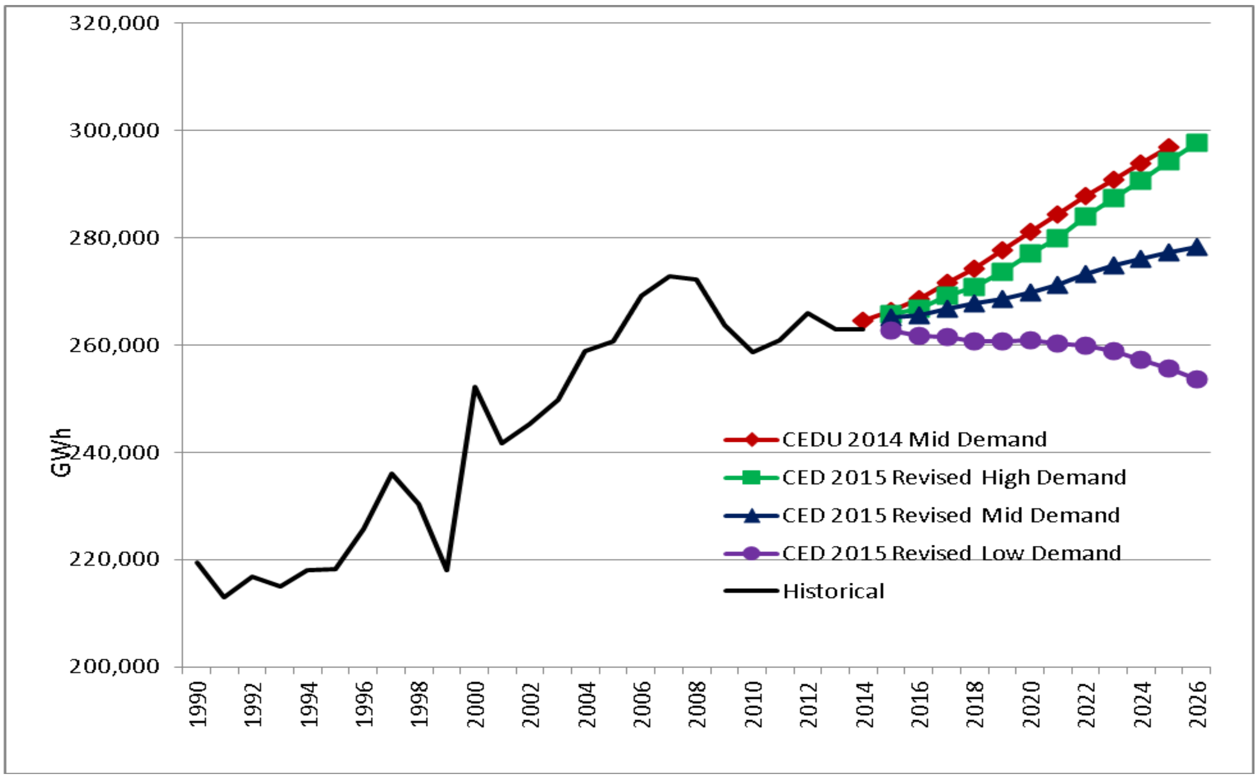
Figure 1: Statewide Baseline Annual Electricity Consumption



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

The significant increase in projected consumption met with self-generation (coming from more PV adoption) in *CED 2015 Revised* reduces statewide electricity retail sales by a greater amount compared to *CEDU 2014* than consumption. Projected statewide sales for the three *CED 2015 Revised* cases and the *CEDU 2014* mid demand case are shown in **Figure 2**. All three new forecast cases are lower than the *CEDU 2014* mid case throughout the forecast period. By 2025, sales in the *CED 2015 Revised* mid case are projected to be almost 20,000 GWh lower than in the *CEDU 2014* mid case, around 6.6 percent. Annual growth from 2014-2025 for *CED 2015 Revised* averages 1.00 percent, 0.48 percent, and -0.26 percent in the high, mid and low cases, respectively, compared to 1.05 percent in the *CEDU 2014* mid case.

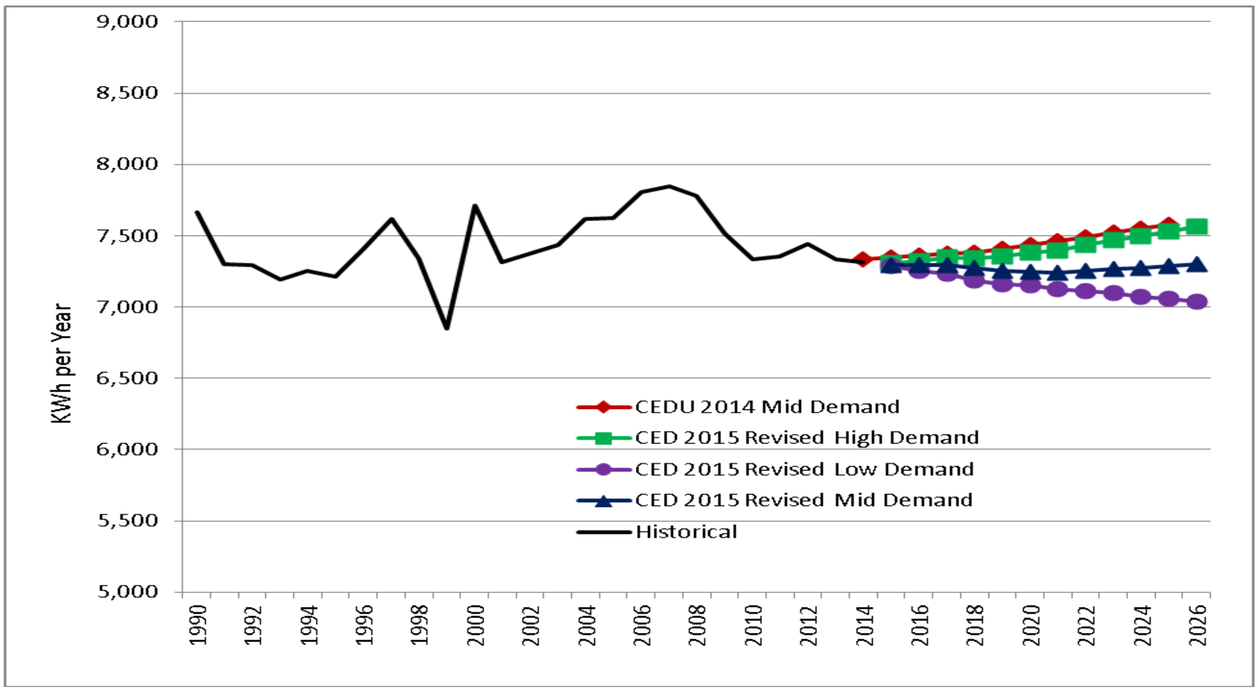
Figure 2: Statewide Baseline Retail Electricity Sales



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

As shown in **Figure 3**, *CED 2015 Revised* baseline per capita electricity consumption is projected to decline through 2020 in the low and mid cases because consumption is projected to grow at lower rate than population. Thereafter, per capita consumption rises slightly in the mid case due to increasing EV use. In the low case, with significantly lower EV projections, per capita consumption continues to drop after 2020. Higher economic/demographic growth in the high demand case, combined with more EVs, increases per capita consumption throughout the forecast period.

Figure 3: Statewide Baseline Electricity Annual Consumption per Capita



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

Projected baseline annual electricity consumption in each *CED 2015 Revised* case for the three major economic sectors—residential, commercial, and industrial (manufacturing, construction, and resource extraction)—is compared with the *CEDU 2014* mid demand case in **Table 2**. Residential consumption in the new mid case grows at a slower rate from 2014-2025 compared to *CEDU 2014* because of the addition of new standards. Residential consumption grows faster than the other sectors because most electric light-duty vehicles are projected to be personal (as opposed to commercial) and because residential plug loads[10] continue to increase. Commercial sector growth in the *CED 2015 Revised* mid case is below that of *CEDU 2014* because of new appliance standards and an adjustment to the impacts of Title 24 standards for existing buildings. A higher number of EVs and faster economic growth partially offset this decrease. The addition of new federal appliance standards, which affect industrial equipment (as well as residential appliances and commercial equipment), results in slightly negative mid case growth for the industrial sector.

10 The term *plug load* does not have a strict definition but in this forecast refers to consumption by various electronic devices (including computers) and smaller appliances and does not include lighting and televisions, which are separate end uses. Residential plug loads, a growing share of total residential consumption, are projected to increase at around 3 percent per year over the forecast period.

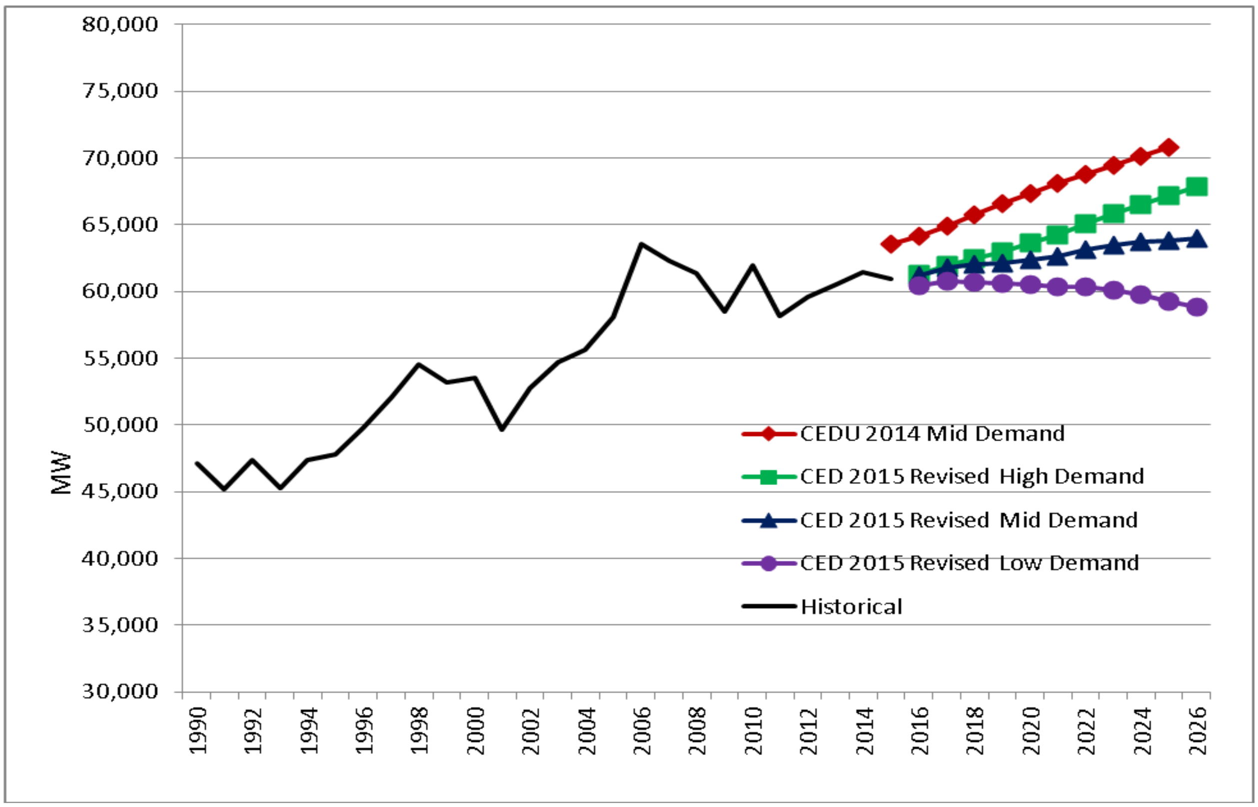
Table 2: Baseline Electricity Consumption by Sector (GWh)

Residential Consumption				
	CEDU 2014 Mid Energy Demand	***CED 2015 Revised High Energy Demand***	***CED 2015 Revised Mid Energy Demand***	***CED 2015 Revised Low Energy Demand***
2014	89,336	89,845	89,845	89,845
2020	97,608	96,255	94,820	93,258
2025	108,807	106,700	103,703	98,558
2026	--	109,142	105,726	99,778
Average Annual Growth, Residential Sector				
2014-2020	1.57%	1.16%	0.90%	0.62%
2014-2025	1.83%	1.58%	1.31%	0.84%
2014-2026	--	1.63%	1.37%	0.88%
Commercial Consumption				
	CEDU 2014 Mid Energy Demand	***CED 2015 Revised High Energy Demand***	***CED 2015 Revised Mid Energy Demand***	***CED 2015 Revised Low Energy Demand***
2014	104,513	106,339	106,339	106,339
2020	113,463	113,982	112,533	110,015
2025	120,252	120,191	117,934	113,829
2026	--	121,262	118,782	114,427
Average Annual Growth, Commercial Sector				
2014-2020	1.38%	1.16%	0.95%	0.57%
2014-2025	1.28%	1.12%	0.95%	0.62%
2014-2026	--	1.10%	0.93%	0.61%
Industrial Consumption				
	CED 2014 Mid Energy Demand	***CED 2015 Revised High Energy Demand***	***CED 2015 Revised Mid Energy Demand***	***CED 2015 Revised Low Energy Demand***
2014	47,932	49,055	49,055	49,055
2020	48,980	51,242	48,735	46,380
2025	48,851	53,504	48,591	45,032
2026	--	53,910	48,574	44,775
Average Annual Growth, Industrial Sector				
2014-2020	0.36%	0.73%	-0.11%	-0.93%
2014-2025	0.20%	0.79%	-0.09%	-0.77%
2014-2026	--	0.79%	-0.08%	-0.76%
Actual historical values are shaded.				

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

Projected *CED 2015 Revised* noncoincident peak demand for the three baseline cases and the *CEDU 2014* mid demand peak forecast is shown in **Figure 4**. By 2025, statewide peak demand in the *CED 2015 Revised* mid case is projected to be almost 10 percent lower than in the *CEDU 2014* mid case. As with sales, higher projected self-generation reduces the growth rate in the new mid case compared to *CEDU 2014*. The peak percentage reduction versus *CEDU 2014* in 2025 is higher than that for sales (6.6 percent) mainly because of the lower starting point for weather-normalized peak demand. Annual growth rates from 2015-2025 for the *CED 2015 Revised* cases average 0.97 percent, 0.46 percent, and -0.28 percent in the high, mid, and low cases, respectively, compared to 1.08 percent in the *CEDU 2014* mid case.

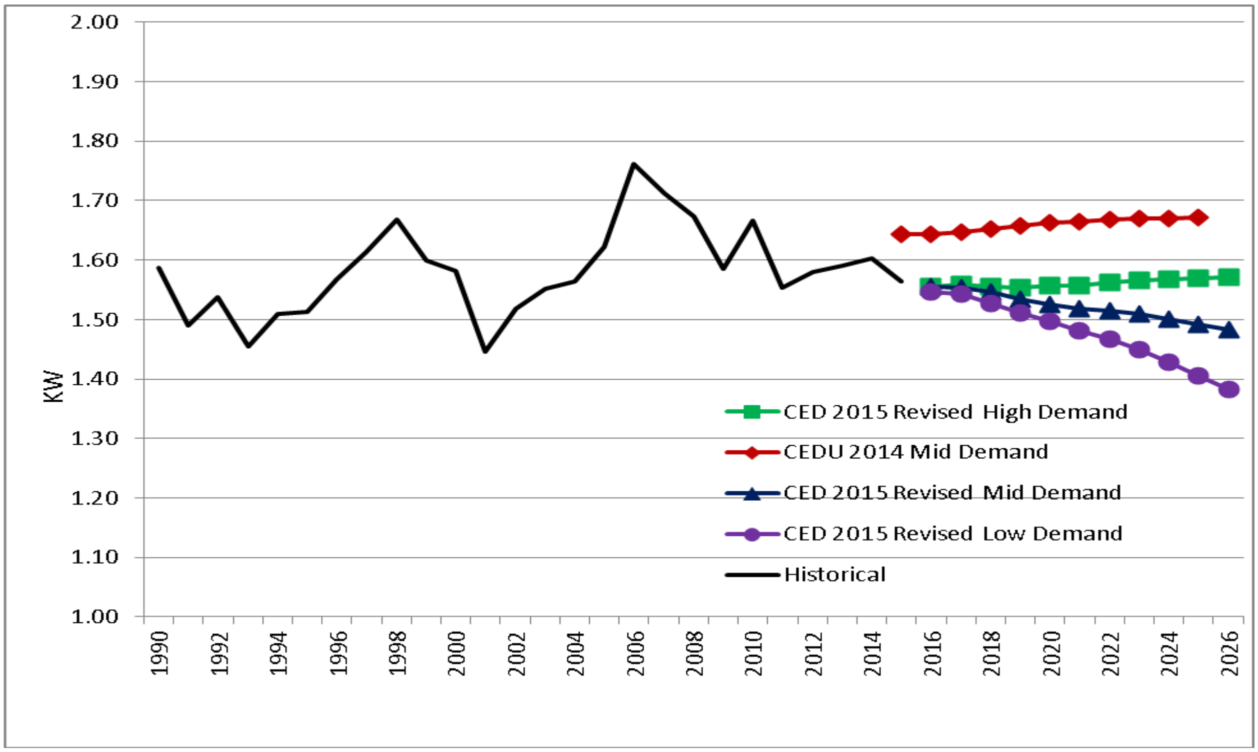
Figure 4: Statewide Baseline Annual Noncoincident Peak Demand



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

Statewide noncoincident peak demand per capita for the three *CED 2015 Revised* cases and the *CEDU 2014* mid case is shown in **Figure 5**. The projected growth rate of peak demand falls below that of population in the mid and low cases. In the high demand case, faster economic growth and significantly less self-generation push peak demand per capita up slightly toward the end of the forecast period, similar to the *CEDU 2014* mid case.

Figure 5: Statewide Baseline Annual Noncoincident Peak Demand per Capita



Source: California Energy Commission, Demand Analysis Office, 2015

Method

Although the methods to estimate energy efficiency impacts and self-generation have undergone refinement, *CED 2015 Revised* uses the same technical methods as previous long-term staff demand forecasts: detailed sector models supplemented with single equation econometric models. A full description of the sector models is available in a staff report.[11]

Geographic Scheme

Past staff energy demand forecasts have been developed for 8 specific planning areas based on utility service territories and, in *CED 2013* and *CEDU 2014*, 16 climate zones. To better serve users of this forecast, staff has modified the planning area definitions for *CED 2015 Revised*.

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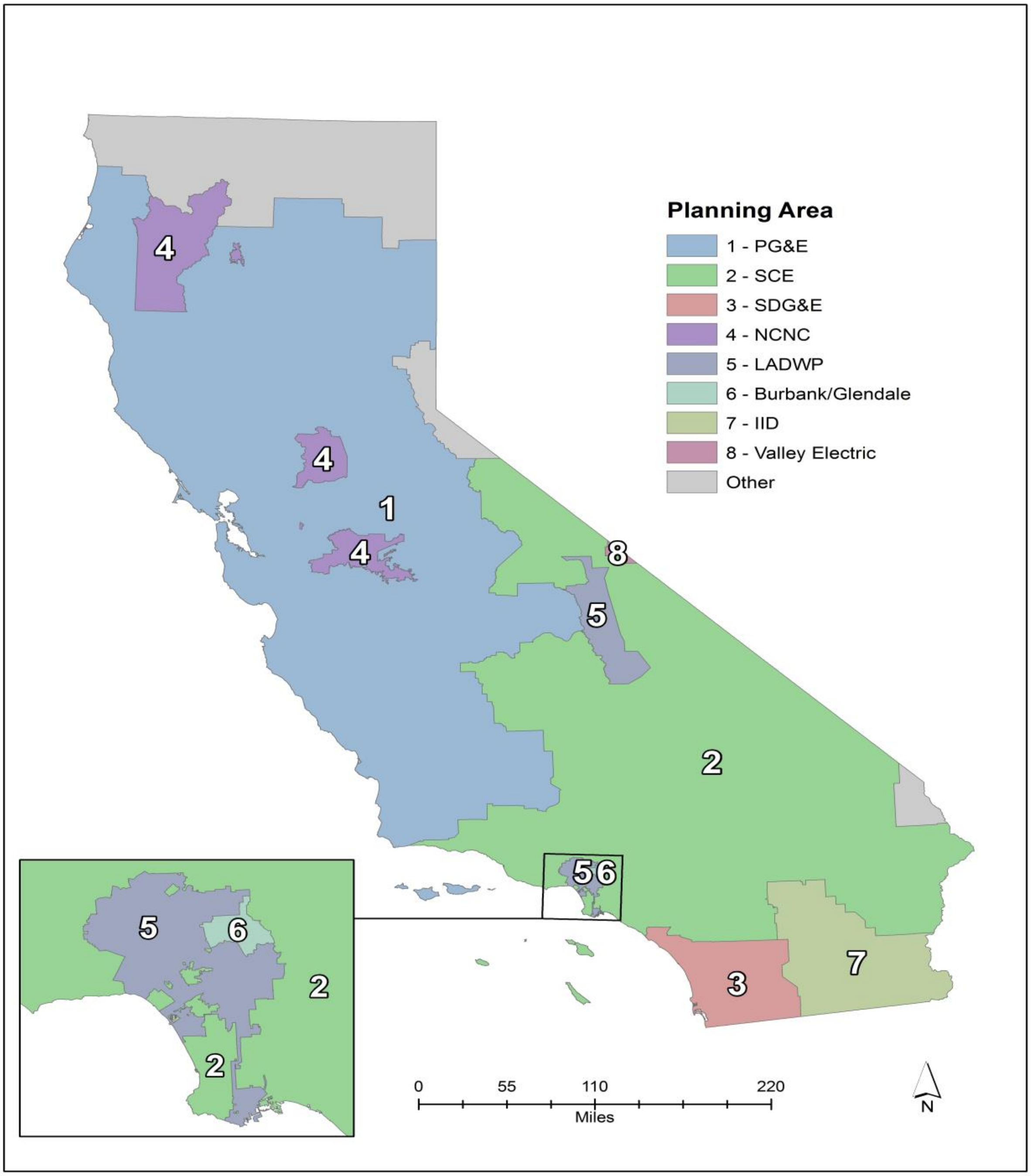
11 http://www.energy.ca.gov/2005publications/CEC-400-2005-036/CEC-400-2005-036.PDF .

The new scheme is more closely based on California's electricity balancing authority areas, where resource plans must maintain the proper balance for load, transmission, and generation.

The key differences come in the SCE and PG&E planning areas. These areas now coincide with the SCE and PG&E transmission access charge (TAC) [12] areas. For the SCE planning area, this change is straightforward: the Pasadena planning area and California Department of Water Resources (DWR) operations in Southern California are added to the previous version of the planning area. Modification to the PG&E planning area required extracting Northern California load-serving entities, such as the Merced and Modesto Irrigation Districts, not affiliated with the California ISO and adding in DWR Northern California operations. The extracted utilities, together with the Sacramento Municipal Utility District (SMUD), form a new planning area, referred to as NCNC. NCNC includes two balancing authorities: the Turlock Irrigation District and the Balancing Authority of Northern California (BANC). The LADWP, Burbank-Glendale (BUGL), Imperial Irrigation District (IID), and SDG&E planning areas remain as they did in previous forecasts. Valley Electric Association, as a separate California ISO TAC area, becomes the eighth planning area. **Figure 6** provides a California map showing the new planning area scheme. The load-serving entities included in each planning area are shown in **Table 3**.

12 A *transmission access charge* (TAC) area is a portion of the California ISO controlled grid where transmission revenue requirements are recovered through an access charge. The California ISO is composed of four TAC areas: SCE, PG&E, SDG&E, and Valley Electric Association.

Figure 6: Forecast Planning Areas, New Scheme



Source: California Energy Commission, Demand Analysis Office, 2015

Table 3: Load-Serving Entities Within Forecasting Planning Areas

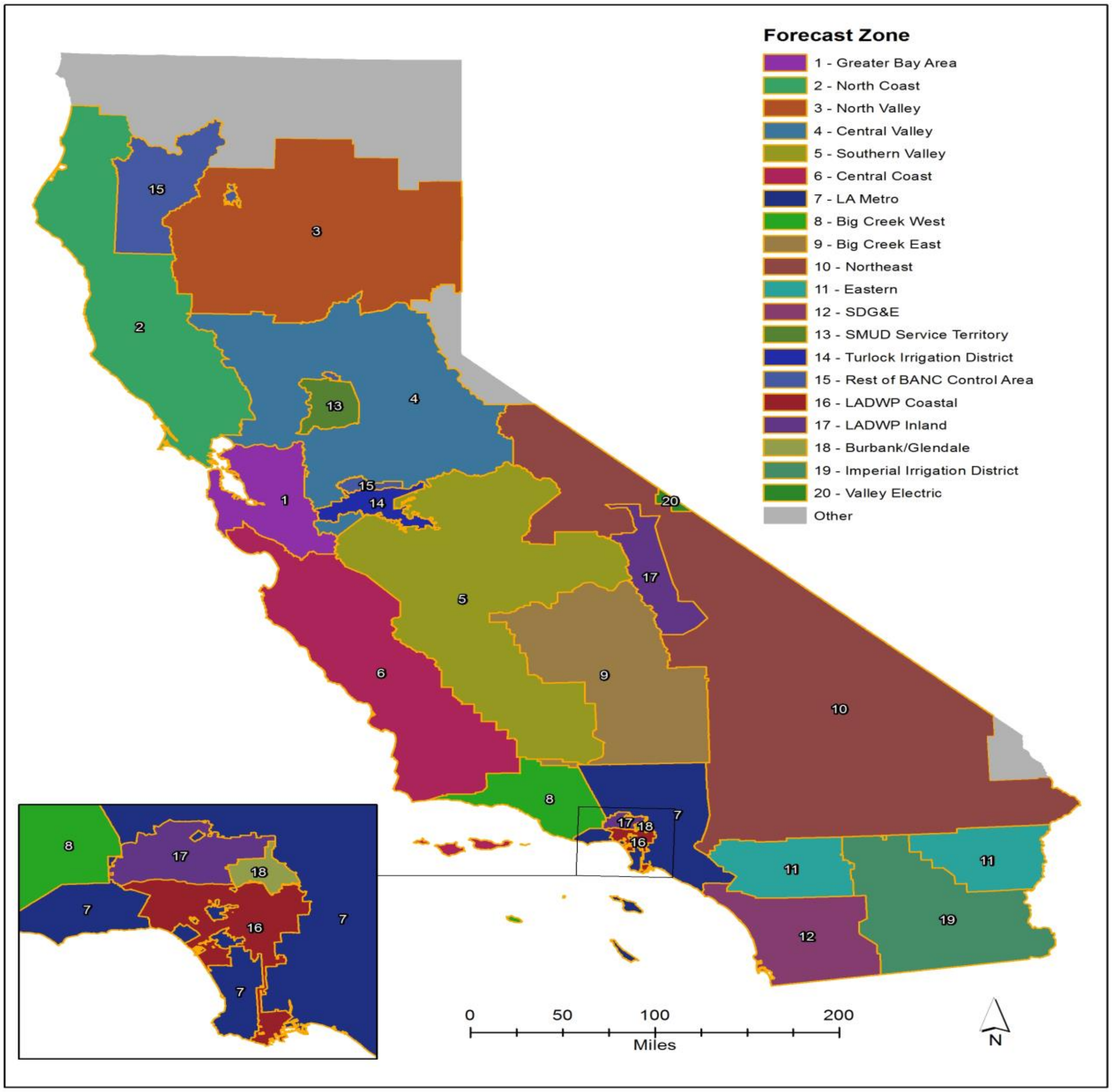
Planning Area	Utilities Included	
PG&E	PG&E Alameda Biggs Calaveras Department of Water Resources (North) Gridley Healdsburg Hercules Island Energy Lassen Lodi Lompoc	Palo Alto Plumas – Sierra Port of Oakland Port of Stockton Power and Water Resources Pooling Authority San Francisco Silicon Valley Tuolumne Ukiah Central Valley Project (California ISO operations)
SCE	Anaheim Anza Azusa Banning Bear Valley Colton Corona Department of Water Resources (South) Metropolitan Water District	Moreno Valley Pasadena Rancho Cucamonga Riverside SCE U.S. Bureau of Reclamation-Parker Davis Vernon Victorville
SDG&E	SDG&E	
NCNC	Merced Modesto Redding Roseville Shasta	SMUD Turlock Irrigation District Central Valley Project (BANC operations)
LADWP	LADWP	
BUGL	Burbank, Glendale	
IID	IID	
VEA	VEA	

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

As part of a continuing effort to provide more geographic granularity in the forecast results, staff increased the number of forecast (climate) zones from 16 to 20. Forecast zones within the California ISO balancing authority were constructed to approximate California ISO transmission zones.[13] Staff can only approximate these zones since they are based on physical infrastructure, while the demand forecast is constrained by political boundaries (for example, counties) for the input data. For NCNC, SMUD was assigned a separate forecast zone. **Figure 7** shows the new forecast zones within a map of California. The new zones are further described in **Table 4** by listing the counties (or parts thereof) included in each.

13 For a description of these zones, see, for example, http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan_July162014.pdf.

Figure 7: Forecast Zones, New Scheme



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

Table 4: New Energy Commission Planning Area/Forecast Zone Scheme by County

Planning Area	Forecast Zone	Definition
1. PG&E	1. Greater Bay Area	Full Counties: Alameda, Contra Costa, San Francisco, San Mateo, Santa Clara
	2. North Coast	Full Counties: Lake, Humboldt, Marin, Mendocino, Napa, Sonoma
	3. North Valley	Full Counties: Butte, Glenn, Plumas, Tehama Partial Counties: Lassen County except for Surprise Valley service territory; Shasta County except for Redding, Shasta Lake, and PacifiCorp service territories; Sierra County except for NV Energy service territory
	4. Central Valley	Full Counties: Amador, Calaveras, Colusa, San Joaquin, Solano, Sutter, Yolo, Yuba Partial Counties: Alpine County except for NV Energy service territory; El Dorado County except for NV Energy service territory; Nevada County except for NV Energy and Truckee-Donner service territories; Placer County except for NV Energy service territory; Stanislaus County except for Modesto Irrigation District and Turlock Irrigation District service territories; Tuolumne County except for SCE service territory; PGE service territory in Sacramento County.
	5. Southern Valley	Full Counties: Madera, Mariposa Partial Counties: Fresno County except for SCE service territory; Kern County except for SCE service territory; Kings County except for SCE service territory; Merced County except for Merced Irrigation District and Turlock Irrigation District service territories; Tulare County except for SCE service territory;
	6. Central Coast	Full Counties: Monterey, San Benito, San Luis Obispo, Santa Cruz Partial Counties: Santa Barbara County except for SCE service territory
2. SCE	7. LA Metro	Partial Counties: Los Angeles County except for LADWP, Glendale, and Burbank service territories; Orange County except for SDGE service territory
	8. Big Creek West	Full Counties: Ventura Partial Counties: SCE service territory in Santa Barbara County
	9. Big Creek East	Partial Counties: Kern County except for PG&E service territory; Kings County except for PG&E service territory; Tulare County except for PGE service territory;
	10. Northeast	Partial Counties: Inyo County except for LADWP service territory; Mono County except for Valley Electric service territory; San Bernardino County except for City of Needles service territory; Tuolumne County except for PG&E service territory; Fresno County except for PG&E service territory;
	11. Eastern	Partial Counties: Riverside County except for IID service territory
3. SDG&E	12. SDG&E	Partial Counties: San Diego County minus IID service territory in San Diego County; SDGE service territory in Orange County
4. NCNC	13. SMUD Service Territory	Partial Counties: Sacramento except for PG&E service territory
	14. Turlock Irrigation District	Merced Irrigation District and Turlock Irrigation District service territories
	15. Rest Of BANC Control Area	City of Shasta Lake, Modesto Irrigation District, Roseville, Redding, and Trinity PUD service territories (this forecasting zone is non-contiguous)
5. LADWP	16. Coastal	Partial Counties: LA City south of Highway 101/134
	17. Inland	Partial Counties: LA City north of Highway 101/134; LADWP service territory in Inyo County
6. Burbank/ Glendale	18. Burbank/Glendale	Burbank and Glendale service territories
7. Imperial Irrigation District (IID)	19. Imperial Irrigation District	Full Counties: Imperial Partial Counties: IID service territory in Riverside County; IID service territory in San Diego County
8. Valley Electric	20. Valley Electric	Partial Counties: Valley Electric service territory in Inyo County; Valley Electric service territory in Mono County;

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

The sector forecasting models have not yet been fully transitioned to the new planning area scheme, but this presents an issue only for PG&E and NCNC. Staff used econometric models to develop a forecast for the new NCNC planning area by sector, and these projections (save SMUD) were subtracted from the PG&E planning area results produced by the sector models. As in previous forecasts, climate zone projections were developed with econometric models, benchmarked to the new planning area results. The econometric models are presented in Appendix A of this report.

In addition to forecast zone results, postprocessed forecasts for load pockets and smaller load-serving entities within California's balancing authority areas are provided for both energy and peak demand in spreadsheet files (Forms 1.1c and 1.5a-e) in the forms accompanying this forecast report.[14] These subregional forecasts are developed using the latest historical load data available, with individual projections "trued up" (brought into alignment) with the appropriate balancing authority area forecasts. Peak forecasts are provided for historically average temperature conditions (referred to as "1 in 2") and more extreme years (1 in 5, 1 in 10, and 1 in 20).

The subregional forecasts also include projections for California's community choice aggregators (CCAs), defined as local governments that aggregate electricity demand within their jurisdictions to procure alternative energy supplies using the existing utility transmission and distribution system. CCAs in operation include Marin Clean Energy, Sonoma Clean Power, and Lancaster Clean Energy. CCAs are expected to increase in number and to play an increasingly prominent role in California's energy future and to contribute to the state's efficiency and renewable goals.

Economic and Demographic Inputs

Projections for statewide economic and demographic growth are summarized in this section. 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 previous forecasts, staff relied on Moody's Analytics and IHS Global Insight to develop the economic growth scenarios to drive the three *CED 2015 Revised* demand cases. Demographic inputs relied on these two sources as well as the California Department of Finance (DOF).

For the economic inputs, staff used the IHS Global Insight *Optimistic* economic scenario for the high demand case, Moody's Analytics *Below-Trend Long-Term Growth* case for the low demand case, and Moody's Analytics *Baseline* economic forecast for the mid demand case. For population and number of households, the low case comes from the DOF's 2015 long-term projections, and the mid and high cases from Moody's Analytics.[16] The key assumptions used

14 http://www.energy.ca.gov/2015_energypolicy/documents/index.html#12172015

15 http://www.energy.ca.gov/2015_energypolicy/documents/index.html#12172015

16 Projections for households and population were very similar in the IHS Global Insight *Optimistic* scenario and the Moody's Analytics *Baseline*, so the latter was used for both the mid and high case forecasts.

by Moody's Analytics and IHS Global Insight to develop the three economic scenarios are provided in **Table 5.**

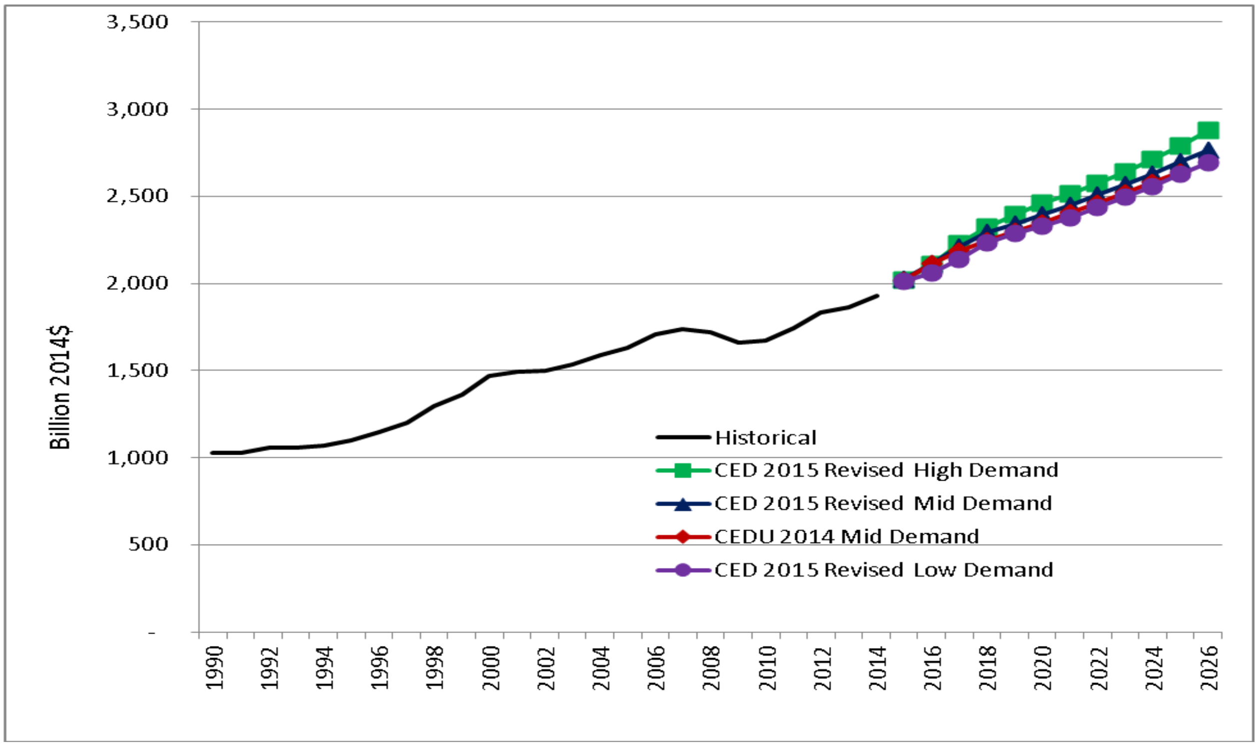
Table 5: Key Assumptions Embodied in *CED 2015 Revised* Economic Cases

High Demand Case (IHS Global Insight *Optimistic* Scenario), July 2015	Mid Demand Case (Moody's Analytics *Baseline* Scenario), July 2015	Low Demand Case (Moody's Analytics *Below-Trend Long-Term Growth* Scenario), July 2015
National unemployment rate falls to 4 percent by 2018.	National unemployment rate stays below 5 percent through 2018.	The unemployment rate stays higher than in the baseline, just above 5 percent in early 2018.
European Central Bank's quantitative easing and the structural reforms implemented by emerging markets yield stronger foreign growth.	The Federal Reserve will normalize U.S. monetary policy by early 2018, but the European Central Bank will not be able to normalize policy until near decade's end.	The Eurozone recovery is slower than expected. Therefore, gains in U.S. exports are slow.
National light-duty vehicles sales reach more than 18.0 million in 2016.	National light-duty vehicle sales are above 16.5 million in 2016.	National light-duty vehicle sales decline to 16.2 million in 2016.
National housing starts improve to near 1.5 million units by the end of 2016.	National housing starts are expected to break 1.6 million units by 2016.	National housing starts decline to 1.2 million units by 2016.
As a result of the higher demand coming with the strong global growth, oil prices initially move above their baseline. As global oil production increases in the second half of 2016, oil prices drop permanently below baseline levels.	Oil prices should slowly rebound given the pullback in investment in North American shale oil production. Global oil demand will also receive a lift from the lower prices.	Oil and gas prices fall in the short term.
With economic growth surging, the Fed raises interest rates in late 2015, and accelerates the pace starting from 2016.	The Federal Reserve has begun what is expected to be a slow process to normalize monetary policy. The first step is to end its bond-buying program, which it did in October. The Fed will begin raising short-term interest rates in late 2015. Short-term interest rates will normalize by early 2018.	Same as in mid case.
There is an expected grand bargain for social insurance in the form of higher taxes on individuals to finance the looming demographic shift of those entering retirement. The Congressional Budget Office released its long term outlook indicating that a continually rising level of federal debt relative to GDP will eventually require an increase in revenue or spending cuts.	The federal government's fiscal situation continues to improve. The deficit is expected to stabilize at just over $500 billion in the next several years. The budget deal reached at the end of 2013 to keep the government open for at least two years is holding firm. This, combined with strong tax revenue growth, has resulted in a shrinking deficit.	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, and housing construction.

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

Historical and projected personal income at the statewide level for the three *CED 2015 Revised* cases and the *CEDU 2014* mid demand case is shown in **Figure 8.**[17] The new mid and low cases are similar to the *CEDU 2014* mid case throughout the forecast period, with the new mid case around 2 percent higher than *CEDU 2014* mid in 2025. Annual growth rates from 2014-2025 average 3.42 percent, 3.10 percent, and 2.85 percent in the *CED 2015 Revised* high, mid, and low cases, respectively, compared to 2.90 percent in the *CEDU 2014* mid case.

Figure 8: Statewide Personal Income

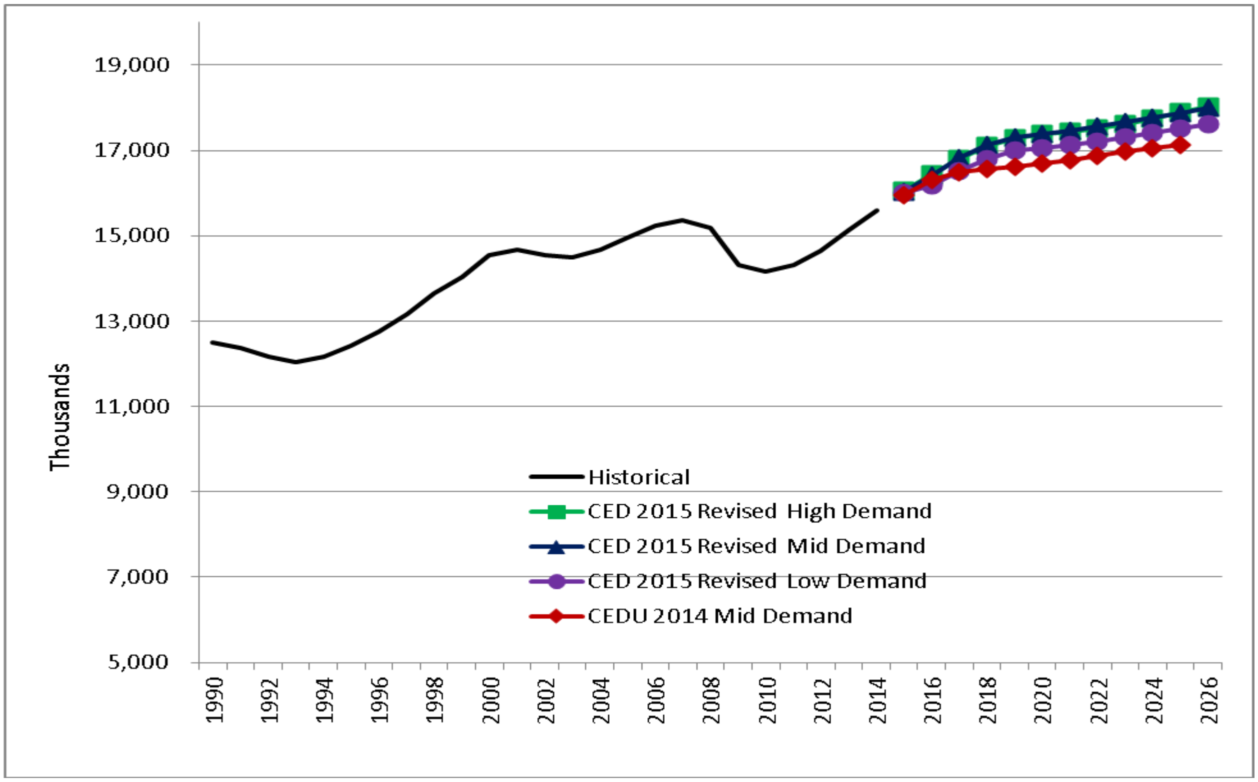


Sources: Moody's Analytics and IHS Global Insight, 2014-2015.

17 To account for periodic revisions to the historical data by Moody's Analytics and IHS Global Insight, the *CEDU 2014* mid economic case in this section is scaled so that levels match those used in *CED 2015 Preliminary* in 2013.

As shown in **Figure 9**, projected growth for statewide non-agricultural employment in all three *CED 2015 Revised* cases is slightly above the *CEDU 2014* mid case, reflecting a slightly more optimistic view of the California economy over the next 10 years. The difference between the new and old mid cases reaches around 4 percent in 2025. Annual growth rates from 2014-2025 average 1.25 percent, 1.25 percent, and 1.06 percent in the *CED 2015 Revised* high, mid, and low cases, respectively, compared to 0.86 percent in the *CEDU 2014* mid case.

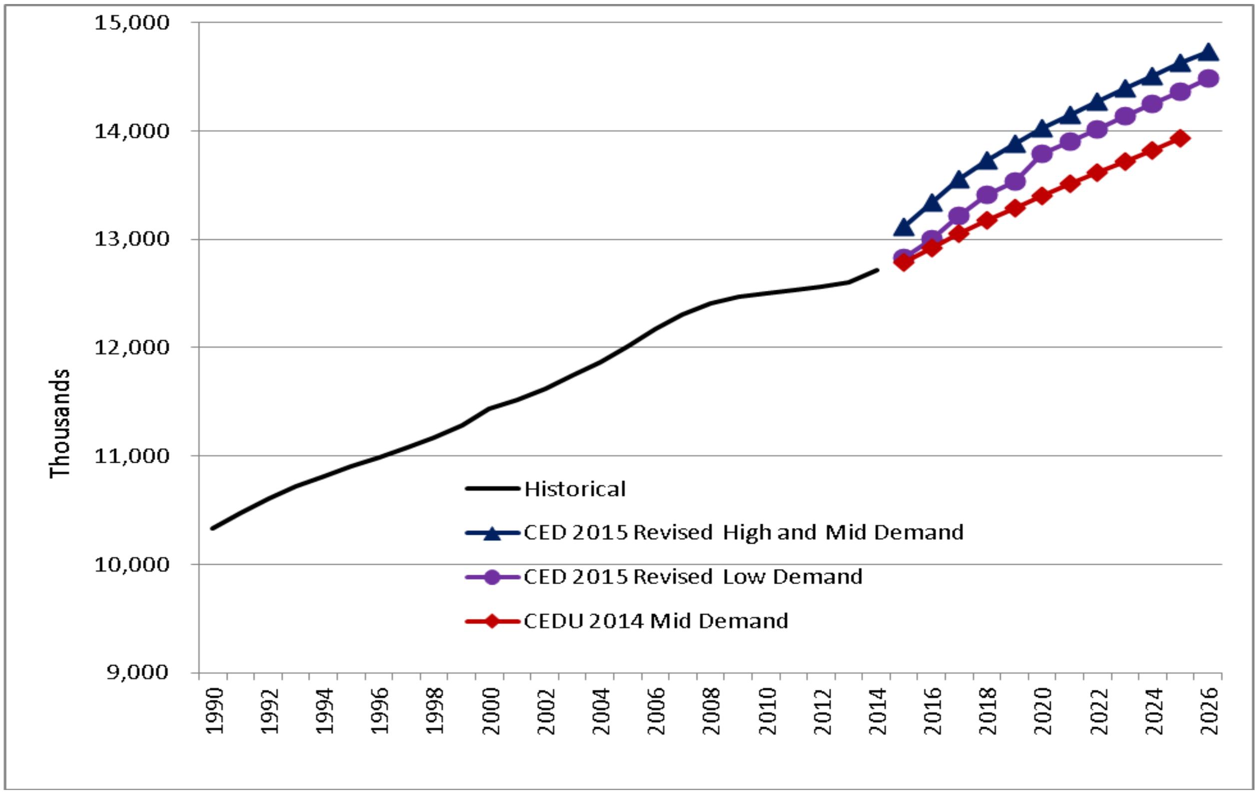
Figure 9: Statewide Nonagricultural Employment



Sources: Moody's Analytics and IHS Global Insight, 2014-2015.

Projections for the number of California households, the key driver for the residential forecast, are shown in **Figure 10**. The two *CED 2015 Revised* cases (high and mid demand cases are identical) project a higher number of households compared to the *CEDU 2014* mid case throughout the forecast period. This result derives from higher projected growth in the short-term and anticipated reductions in persons per household in California, consistent with assumptions from Moody's Analytics, IHS Global Insight, and DOF. In 2025, the number of households in the new mid case is around 5 percent higher than in *CEDU 2014* mid.

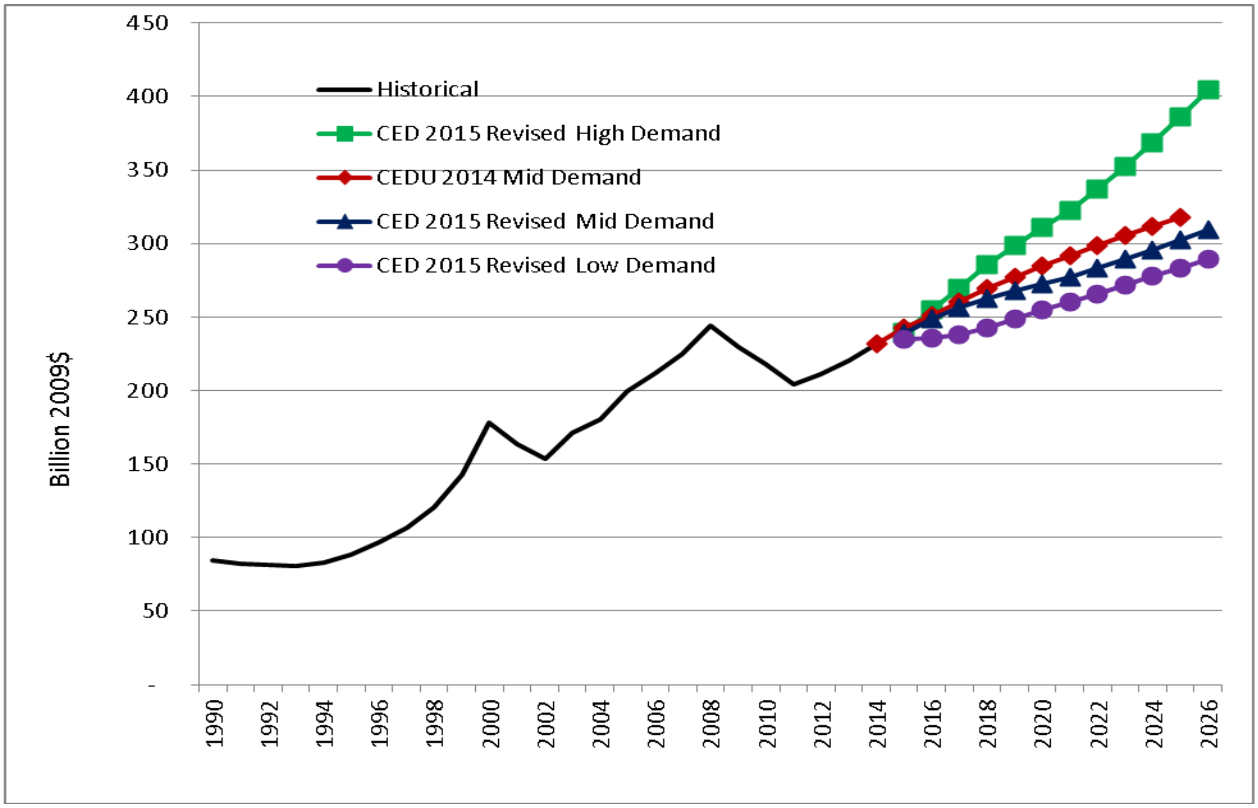
Figure 10: Statewide Number of Households



Sources: California Department of Finance and Moody's Analytics, 2014-2015.

Historical and projected statewide manufacturing dollar output, a key driver for the industrial forecast, is shown in **Figure 11**. The *CED 2015 Revised* mid case grows more slowly compared to *CEDU 2014*, reflecting lower growth in old-line manufacturing, including chemicals, textiles, and plastics, based on recent historical trends. The high demand case from IHS Global Insight assumes a much more optimistic future for manufacturing in California compared to Moody's Analytics, as in previous forecasts. Annual growth rates from 2014-2025 average 4.72 percent, 2.43 percent, and 1.82 percent in the *CED 2015 Revised* high, mid, and low cases, respectively, compared to 2.89 percent in the *CEDU 2014* mid case.

Figure 11: Statewide Manufacturing Output



Sources: Moody's Analytics and IHS Global Insight, 2014-2015.

Electricity Rates

Electricity rate scenarios for *CED 2015 Revised* were developed using a new staff electric rate model. This model is made up of a set of simultaneous equations that together estimate future revenue requirements, allocate them to rate classes, and calculate annual average rates by class. Planning area rates are calculated as a sales-weighted average of utility rates within the planning area.

The staff model combines staff scenario inputs with utility-specific data. Staff scenario inputs include natural gas, carbon and renewable prices, infrastructure costs, and electricity sales and demand. Utility-specific data are used for other elements of revenue requirements, such as procurement cost for hydroelectric, nuclear, coal, other long term contracts, debt service, customer service costs, and public purpose programs. Utility-specific data were compiled from demand forecast and resource plan forms submitted by larger utilities in support of the *2015 IEPR*. Information on planned or adopted rate increases was compiled from CPUC proceedings and public utility rate action documentation. Data on currently adopted rates were used to calibrate the forecast.

The largest component of a utilities' electric revenue requirement is the cost of procuring electricity supply. This includes the cost of purchased power, capital expenditures, fuel, and operating costs for utility-owned resources. To estimate procurement costs, staff first identified energy production and costs for existing resources, either owned or under long-term contract. The cost of additional energy and capacity needed to meet each utility's stated Renewables Portfolio Standard (RPS) targets, serve load, and ensure reliability are then calculated. An average price for incremental renewable purchases was developed using mid-case levelized costs from the *Estimated Cost of New Renewable and Fossil Generation in California* staff report.[18] Weighting each technology cost by percentage of renewable resource additions in the staff production simulation model produced a procurement price of $96 per megawatt hour (MWh) in 2013 (in 2014 dollars), declining to $61 per MWh in 2026.

After a stated annual renewable portfolio goal for a given utility is met, residual need is assumed to be purchased at the wholesale electricity price, which is estimated assuming an average annual heat rate of 8,000 British thermal units per kilowatt hour (Btu/kWh) and using natural gas price projections developed for the draft *2015 Natural Gas Outlook* report.[19] These natural price projections blend New York Mercantile Exchange forward prices with North American Gas-Trade Model results. The wholesale electricity market price and fuel costs also include the cost of cap-and-trade greenhouse gas emission (GHG) allowances. Staff developed allowance price projections for the *2015 IEPR*-based on recent auction results and analysis by the California Air Resources Board (ARB) Emissions Market Assessment Committee and the Market Simulation Group.[20]

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18 California Energy Commission. March 2015. *Estimated Cost of New Renewable and Fossil Generation in California,* CEC-200-2014-003, pp. 151-156.

19 California Energy Commission. November 2015. Draft *2015 Natural Gas Outlook*, CEC-200-2015-007-SD, pp. 20-22.

20 See http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN203794_20150309T125148_Preliminary_2015_IEPR_Carbon_Price_Projections_Assumptions.xlsx for 2015 Preliminary IEPR Greenhouse Gas Price Scenarios. "Forecasting Supply and Demand Balances in California's Greenhouse Gas Cap-and-Trade Market" March 12, 2013 at http://www.arb.ca.gov/cc/capandtrade/simulationgroup/msg_final_v25.pdf.

Growth in distribution revenue requirements are driven primarily by the capital investment needed to maintain and expand the distribution system and supporting infrastructure. Current data on distribution revenue requirements, collected from utility data submittals, financial statements, and board or CPUC decisions, are incorporated into the model. For IOUs, historical and planned capital expenditures to serve load and customer growth were projected using marginal cost estimates from the most recent CPUC general rate case. For public utilities, data on planned capital budgets were used when available for the mid demand case. Annual growth in distribution revenue requirements varies between about 1.5 to 2 percent in the high demand case to 3 percent in the low demand case.

Transmission revenue requirements were developed using utility *2015 IEPR* data submittals, recent transmission owner rate cases, and the California ISO 2015 Transmission Access Charge Forecasting Model.[21] This includes renewables integration projects and ongoing reliability upgrades.

The rate model was used to generate mid, high and low rate cases that vary electricity demand, natural gas prices, and carbon prices. The demand forecasts used as input to these cases are the *2015 IEPR* preliminary demand forecast cases.[22] The low rate (high demand) case assumes high demand, low natural gas and GHG allowance prices, and less infrastructure investment. The high rate (low demand) case assumes lower electricity demand, higher natural gas and allowance prices, and more infrastructure investment.

Electricity rate scenarios for the five major planning areas for selected years for the three major sectors by demand case are shown in **Table 6**. A full listing of historical and projected rates by planning area is available in the demand forms accompanying this report.[23] The effect of increasing rates on the forecast is determined by model price elasticities of demand,[24] which average about 10 percent across the sectors.

21 CAISO 2014-15 Transmission Access Charge Forecast Model, May 2015. http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx

22 Kavalec, Chris and Asish Gautam, 2015. *California Energy Demand 2016-2026 Preliminary Forecast.* California Energy Commission, Electricity Assessments Division. Publication Number CEC-200-2015-003. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN205141_20150623T153206_CALIFORNIA_ENERGY_DEMAND_20162026_PRELIMINARY_ELECTRICITY_FOREC.pdf

23 http://www.energy.ca.gov/2015_energypolicy/documents/index.html#12172015

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

Table 6: Rates by Demand Case for Five Major Planning Areas (2014 cents per kWh)

Planning Area	Year	Residential			Commercial			Industrial		
		High	Mid	Low	High	Mid	Low	High	Mid	Low
PG&E	2014	17.36	17.36	17.36	17.45	17.45	17.45	12.33	12.33	12.33
	2016	17.71	17.93	18.70	17.80	18.03	18.75	12.58	12.81	13.26
	2020	17.78	18.77	19.71	17.87	18.87	19.77	12.64	13.42	13.99
	2026	17.37	18.87	20.57	17.46	18.97	20.64	12.36	13.49	14.60
SCE	2014	17.19	17.19	17.19	14.66	14.66	14.66	11.67	11.67	11.67
	2016	16.78	16.90	18.03	13.92	14.08	15.17	11.35	11.45	12.28
	2020	17.19	18.38	19.62	14.07	15.05	16.27	11.67	12.53	13.38
	2026	17.33	19.34	21.57	14.23	15.46	17.26	11.83	12.92	14.16
SDG&E	2014	17.86	17.86	17.86	17.16	17.16	17.16	11.86	11.86	11.86
	2016	18.02	18.27	19.38	17.10	17.27	18.42	11.82	11.93	12.73
	2020	17.89	19.32	20.80	16.21	17.41	18.84	11.20	12.03	13.02
	2026	17.91	19.89	22.54	16.14	17.49	19.73	11.15	12.08	13.63
NCNC	2014	13.80	13.80	13.80	13.80	13.80	13.80	10.30	10.30	10.30
	2016	14.17	14.36	14.59	14.07	14.27	14.49	10.47	10.62	10.79
	2020	14.24	14.84	15.63	13.71	14.30	15.07	10.20	10.64	11.23
	2026	14.53	15.80	17.57	13.35	14.54	16.20	9.93	10.82	12.07
LADWP	2014	15.01	15.01	15.01	15.20	15.20	15.20	13.14	13.14	13.14
	2016	15.72	15.88	16.09	15.92	17.03	17.45	13.76	14.38	14.68
	2020	16.56	17.37	18.57	16.77	18.03	20.13	14.50	15.54	16.94
	2026	16.18	17.97	20.85	16.38	18.15	22.61	14.17	15.88	19.03

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

Conservation/Efficiency Impacts

Energy Commission demand forecasts seek to account for efficiency and conservation *reasonably expected to occur*. Reasonably expected to occur initiatives have been split into two types: committed and AAEE. The *CED 2015 Revised* baseline forecasts continue that distinction, with only committed efficiency included. Committed initiatives include utility and public agency programs, codes and standards, and legislation and ordinances having final authorization, firm funding, and a design that can be readily translated into characteristics capable of being evaluated and used to estimate future impacts (for example, a package of IOU incentive programs that has been funded by CPUC order). In addition, committed impacts include price and other market effects not directly related to a specific initiative.

CED 2015 Revised also includes estimates of AAEE savings for the IOU service territories and the two largest POUs. These savings are not yet considered committed but are deemed reasonably likely to occur, and include impacts from future updates of building codes, appliance standards, and utility efficiency programs expected to be implemented after 2015.

Five savings scenarios were developed for the IOUs and three scenarios developed for the POUs. Chapter 2 discusses both committed and AAEE savings.

Self-Generation

Energy Commission demand forecasts attempt to account for all major programs designed to promote self-generation, using a bottom-up approach from system sales. Incentive programs include:

- Emerging Renewables Program (ERP).
- New Solar Homes Partnership (NSHP).
- California Solar Initiative (CSI).
- Self-Generation Incentive Program (SGIP).
- Incentives administered by public utilities such as SMUD, LADWP, IID, Burbank Water and Power, City of Glendale, and City of Pasadena.

The ERP and NSHP are managed by the Energy Commission, and the CSI and SGIP by the CPUC. The forecast also accounts for power plants reporting to the Energy Commission in Form CEC 1304, which is used as the principal source of information.[25] Staff included only power plants that are explicitly listed as operating under cogeneration or self-generation mode.

The general strategy of the ERP, NSHP, CSI, and SGIP programs is to encourage demand for self-generation technologies, such as PV systems, with financial incentives until the size of the market increases to the point where economies of scale are achieved and capital costs decline. The extent to which consumers see real price declines will depend on the interplay of supplier expectations, the future level of incentives, and demand as manifested by the number of states or countries offering subsidies.

Residential PV and solar water heating adoption are forecast using a predictive model developed in 2011, based on estimated payback periods and cost-effectiveness, determined by upfront costs, energy rates, and incentive levels. For *CED 2015 Revised*, staff modeled residential rates for the IOUs using existing or proposed tier structures and estimated hourly load patterns rather than assuming average rates/usage as in past forecasts. This change resulted in a significant increase in projected adoption of PV systems, as shown below. Staff has not yet made these modifications for the POU planning areas.

Commercial PV adoption is modeled similarly to residential, with adoptions developed by building type (hospitals, schools, and so on). The same predictive model is used to forecast commercial combined heat and power (CHP) technologies, employing estimated load shapes by building type. Results for adoption in both the commercial and residential sectors differ by

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25 See http://www.energy.ca.gov/forms/cec-1304.html.

demand cases since projected electricity and natural gas rates and number of homes vary across the cases. Lower electricity demand corresponds to higher adoptions since the effect from higher rates outweighs lower growth in households. Self-generation for other technologies and sectors is projected using a trend analysis and does not vary by demand case. Appendix B provides much more detail on the self-generation modeling method.

Cases for self-generation are defined with the economic and demographic drivers and electricity rate assumptions for high, mid, and low demand. For the high demand case, the case is constructed to yield lower self-generation and thus higher sales and peak demand for the forecast overall. Although economic and demographic growth is faster in the high demand case, electricity rates are lower, and PV system costs are assumed to decline more slowly compared to the other cases. The opposite is true for the low demand case (higher rates, faster cost decreases, more self-generation). The mid case assumptions lie between those of the high and low.

Historical and projected peak reduction impacts of self-generation for the three *CED 2015 Revised* demand cases and the *CEDU 2014* mid case are shown in **Figure 12**. Self-generation is projected to reduce peak load by more than 6,900 megawatts (MW) in the new mid case by 2025, an increase of more than 2,000 MW compared to *CEDU 2014*. Residential PV is a key factor in this increase, as shown in **Figure 13**. By 2026, residential PV peak impacts reach almost 3,000 MW in the *CED 2015 Revised* mid case, corresponding to more than 7,700 MW of installed capacity.

At some point, continued growth in PV adoption will likely reduce demand for utility-generated power at traditional peak hours to the point where the hour of peak utility demand is pushed back to later in the day. This means that future PV peak impacts could decline significantly as system performance drops in the later hours. This possibility has not been incorporated into the demand forecast through *CED 2015*, since staff has not yet developed models to forecast hourly loads in the long term. Staff expects to develop this capability for the *2017 Integrated Energy Policy Report* (*2017 IEPR*), and such an adjustment to PV peak impacts could significantly affect future peak forecasts.[26]

Appendix B provides more discussion on the results, modeling method, historical data, case definitions, and policy uncertainties, including net energy metering. The demand forms accompanying this report[27] provide annual results for energy and peak impacts for each planning area and statewide.

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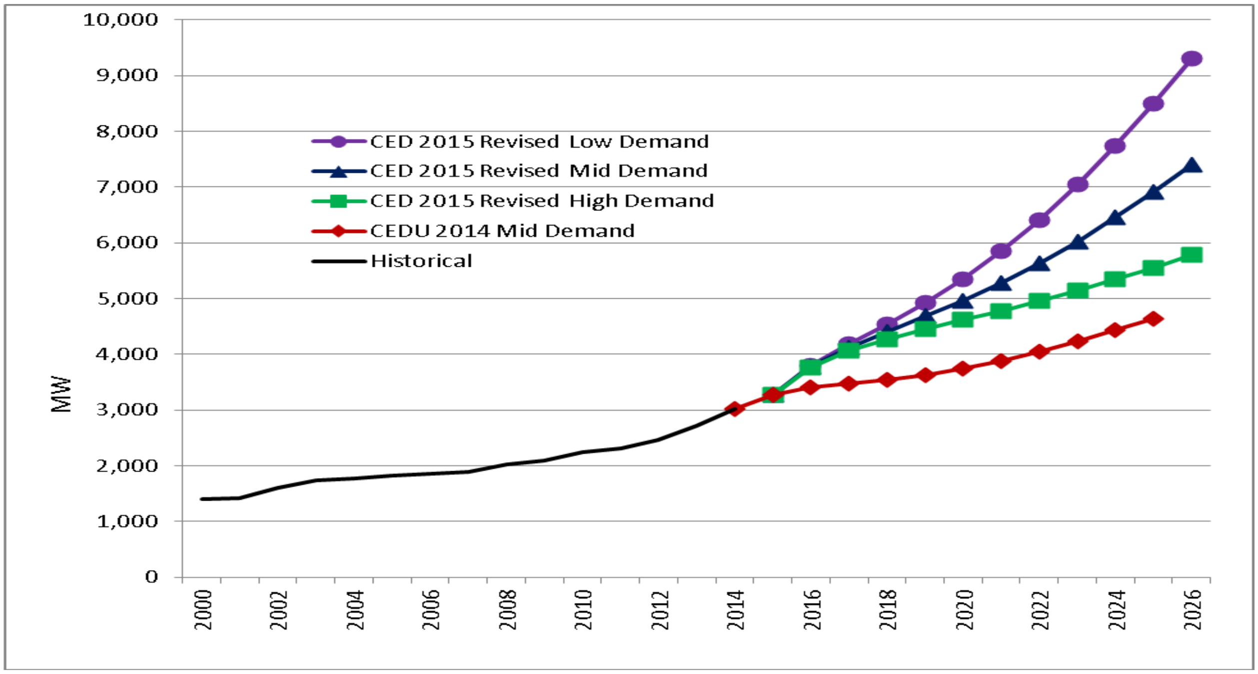
26 SCE has developed this capability and, as a result, its latest peak forecasts grow at a markedly higher rate than the *CED 2015 Revised* SCE peak forecasts.

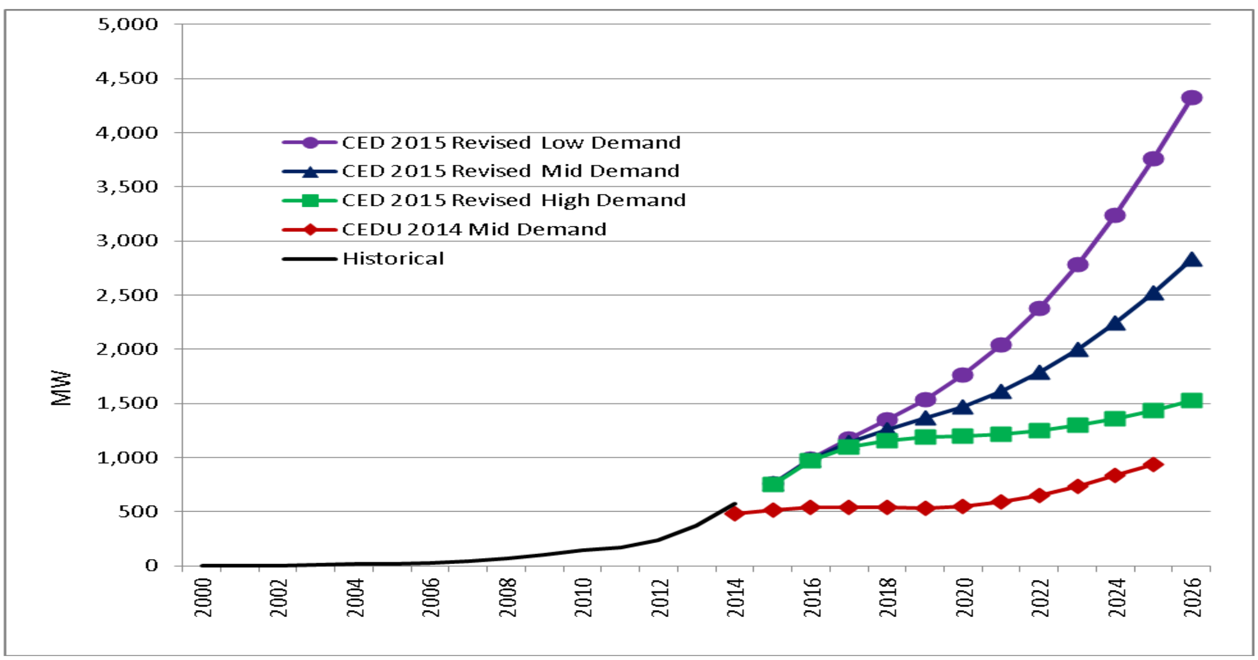
27 http://www.energy.ca.gov/2015_energypolicy/documents/index.html#12172015.

Figure 12: Statewide Self-Generation Peak Reduction Impact



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

Figure 13: Statewide Residential PV Peak Reduction Impact



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

Light-Duty Plug-In Electric Vehicles

CED 2015 Revised incorporates new scenarios for fuel consumption by on-road electric light-duty vehicles, including battery electric and plug-in hybrid electric, provided by the Energy Commission's Transportation Energy Forecasting Unit.[28] Case results are generated with a discrete choice model for light-duty vehicles and depend on current and projected vehicle attributes (price, fuel efficiency, performance, and so on) for numerous classes and vintages of conventional and alternative fuel vehicles.[29]

The mid case for EVs was developed to be consistent with a "most-likely" case for compliance with California's zero-emission vehicle (ZEV) regulation, provided by ARB staff. To reach ZEV levels of EV purchase, staff reduced projected EV prices, using a trajectory designed to match gasoline vehicle prices for similar classes by 2050, and increased an EV preference parameter over time within the vehicle choice model.[30] The high case assumes the increased EV preference parameter as well as EV prices that match those of similar gasoline vehicles by 2030. The low case represents "business as usual," so that electric vehicle prices stay well above those of gasoline vehicles and general consumer preference toward EVs remains constant over the forecast.

The resulting forecast cases for electricity consumption statewide by EVs in the three *CED 2015 Revised* cases are shown in **Figure 14**. These projections assume that EVs and gasoline vehicles have similar annual mileage.[31] EV consumption at the planning area level is provided in Volume 2. **Figure 15** shows the associated EV stock for the three cases, which reaches around 2.5 million in the mid case by 2026.

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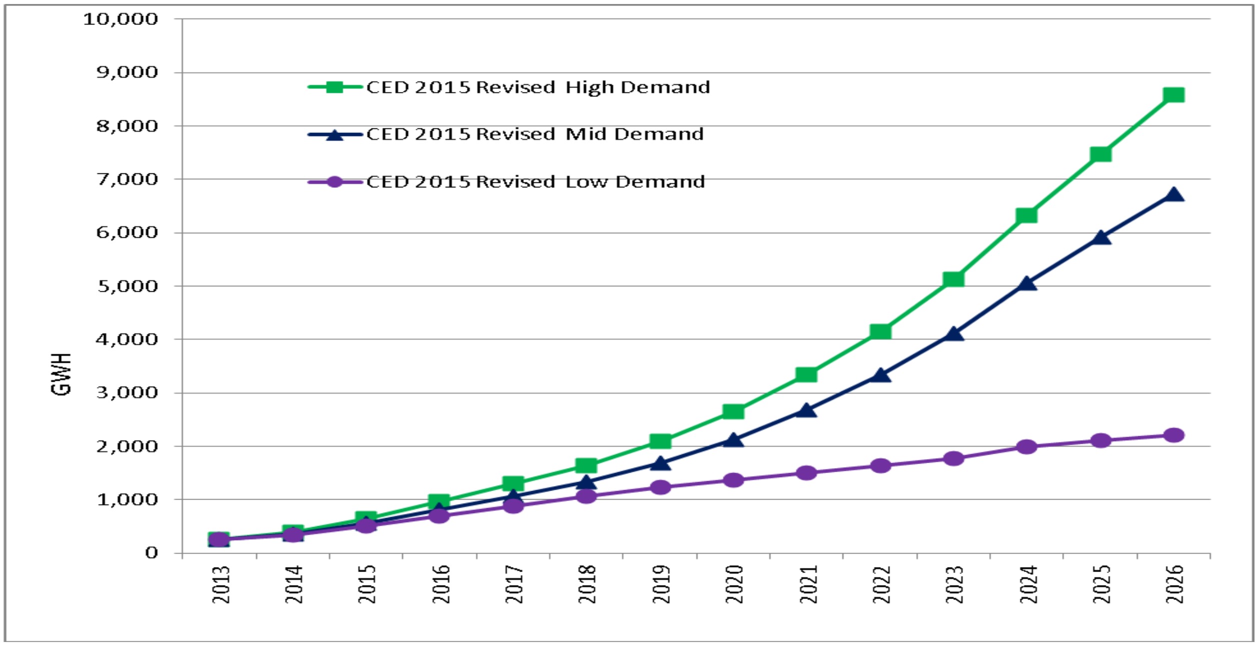
28 Presented at an IEPR workshop on November 24, 2015. http://www.energy.ca.gov/2015_energypolicy/documents/index.html#11242015 .

29 For information on DynaSim, see https://efiling.energy.ca.gov/getdocument.aspx?tn=203899.

30 This parameter results from the vehicle choice model estimation process, and represents vehicle owners' general willingness to purchase an EV beyond specified vehicle attributes such as range and recharging time. Modifying this parameter upward assumes more general willingness to purchase, all else equal.

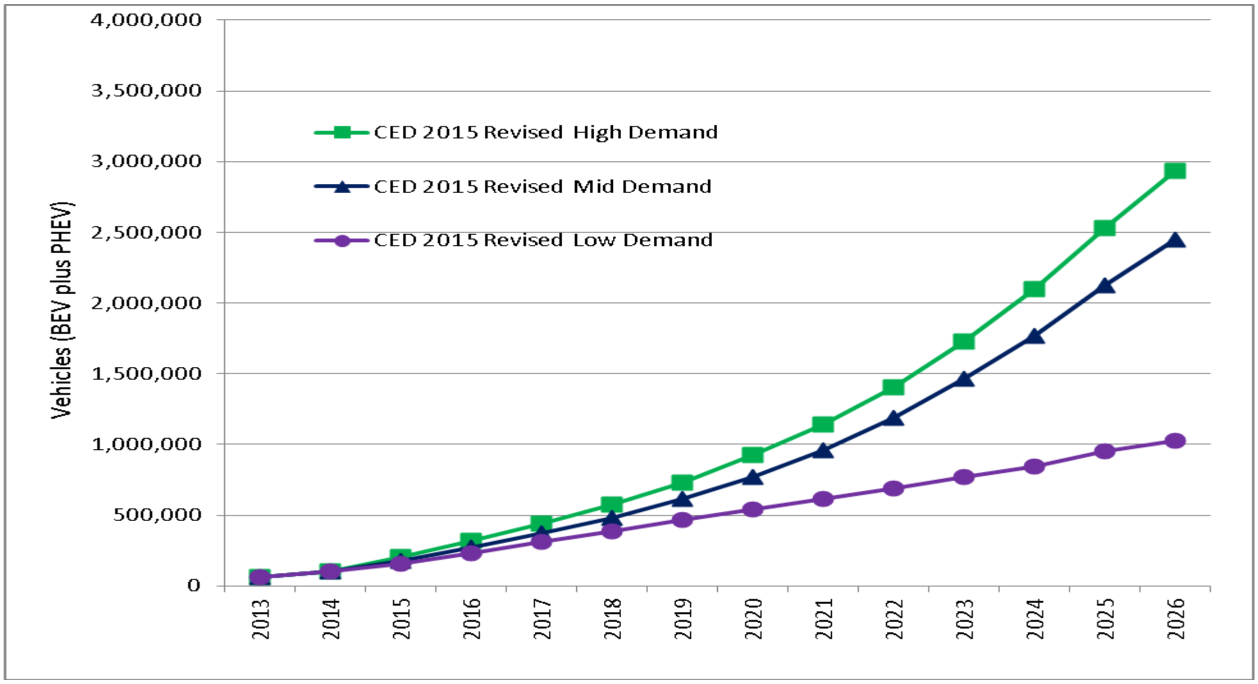
31 This assumption may overestimate EV mileage, given the relatively low range and nontrivial recharge times for these vehicles. Staff has begun a survey effort designed to gauge the travel habits of EV owners.

Figure 14: Electric Light-Duty Vehicles Electricity Consumption



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

Figure 15: Stock of Electric Light-Duty Vehicles



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

The statewide EV forecast was distributed to planning areas and climate zones using regression analysis. EV ownership by county from California Department of Motor Vehicle (DMV) records was specified as a function of per capita income and whether the county could be considered mainly urban or rural. Predicted county results for the forecast period were then mapped to the planning areas and forecast zones. To convert EV consumption to peak impacts for each planning area and forecast zone, staff used a factor derived from a recent study of EV charging behavior by the U.S. Department of Energy (DOE).[32] From the study results, staff estimated a peak factor of around 0.13[33] (that is, MW=GWh×0.13). For the *2017 IEPR*, staff plans to develop EV peak factors and charging load shapes specifically for California.

Additional Electrification

Significant increases in other transportation-related electricity use in California are expected to occur through port, truck stop, and other electrification. In particular, regulations implemented by the ARB[34] are aimed at reducing emissions from container, passenger, and refrigerated cargo vessels docked at California ports. Early in 2015, the Energy Commission's Demand Analysis Office hired a consultant to develop projections of off-road transportation electrification, and these are incorporated in *CED 2015 Revised*. The consultant study[35] examined the potential for additional electrification in airport ground support equipment, port cargo handling equipment, shore power,[36] truck stops, forklifts, and transportation refrigeration units.

The consultant study includes high, mid and low cases, representing aggressive, most likely, and minimal increases in electrification, respectively. The projected vehicle/equipment populations for the various applications in this study are based on macroeconomic growth data from the U.S. Bureau of Economic Analysis, Moody's Analytics and IHS Global Insight for California applied to current populations. The cases vary by the percentage electrification assumed for off-road vehicles or applications.

Electrification impacts from the study were quantified at the state level. To incorporate them into the baseline forecast, it was necessary to allocate impacts across sector and planning area. Electrification impacts from port cargo handling equipment, shore power, truck stop electrification, and airport ground support were added to the transportation, communication,

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32 U.S. Department of Energy, December 2014. *Evaluating Electric Vehicle Charging Impacts and Customer Charging Behaviors – Experiences From Six Smart Grid Investment Grant Projects.*

33 In the underlying load shape for this factor, around 75 percent of charging is done in off-peak hours.

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

35 The study was conducted by the University of California, Davis Institute of Transportation and Aspen Environmental Group. The final report, *California Electrification Demand Forecast for Off-Road Transportation Activities*, is not finalized at the time of writing and does not yet have an Energy Commission publication number.

36 Power required for basic ship operations when berthed.

and utilities (TCU) sector. Impacts for transport refrigeration units and forklifts were assigned to multiple sectors, including industrial, TCU, and certain commercial building types. Given that some portion of electrification is already embedded in *CED 2015 Revised* through extrapolation of historical trends, staff estimated *incremental* impacts of the consultant study projections.[37] Staff did not make any other adjustments to the projected impacts. The statewide impacts in each forecast year were distributed based on the relative shares of total electricity use projected for each sector and planning area.

The statewide incremental electrification impacts incorporated in *CED 2015 Revised* are shown in **Table 7**. Most of the impacts come from forklifts and shore power; together these applications account for around 80 percent of the total. Results for the five major planning areas are provided in Volume 2 of this report.

Table 7: Additional Electrification, Statewide (GWh)

Technology	Demand Case	2016	2018	2020	2022	2024	2026
Airport Ground Support Equipment	High	2	7	12	18	24	30
	Mid	1	4	8	11	15	19
	Low	1	2	4	6	8	9
Port Cargo Handling Equipment	High	9	32	60	96	141	194
	Mid	4	15	29	46	67	91
	Low	2	8	14	22	32	44
Shore Power	High	53	147	242	267	294	321
	Mid	44	116	172	185	200	216
	Low	43	106	144	154	165	177
Truck Stops	High	1	5	10	16	22	30
	Mid	1	2	5	8	11	15
	Low	0	0	0	0	0	1
Forklifts	High	59	189	334	449	577	716
	Mid	39	123	215	270	330	395
	Low	-	-	-	-	-	-
Transportation Refrigeration Units	High	11	36	64	105	151	200
	Mid	2	5	9	16	23	31
	Low	0	0	0	1	1	1
Total	High	136	416	722	951	1,210	1,492
	Mid	91	266	437	536	646	767
	Low	46	116	163	184	207	232

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

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

Demand Response

The term “demand response” encompasses a variety of programs, including traditional direct control (interruptible) programs and new price-responsive demand programs. A key distinction is whether the program is dispatchable or event-based. *Dispatchable programs*, such as direct control, interruptible tariffs, or demand bidding programs, have triggering conditions that are not under the control of and cannot be anticipated by the customer. Nonevent-based programs are not activated using a predetermined threshold condition, which allows the customer to make the economic choice whether to modify usage in response to ongoing price signals. Impacts from committed nonevent-based programs have traditionally been included in the demand forecast.

Nonevent-based-program impacts are likely to increase in the coming years, and expected impacts incremental to the last historical year for peak (2015) affect the demand forecast.[38] Staff used the annual IOU filings for demand response[39] (submitted to the CPUC) to identify impacts from committed nonevent demand response programs, which include real-time or time-of-use pricing and permanent load shifting. Impacts are shown in **Table 8**.

Table 8: Estimated Nonevent-Based Demand Response Incremental Program Impacts (MW)

Year	PG&E	SCE	SDG&E
2015	11	20	0
2016	26	20	12
2017	29	25	13
2018	30	28	14
2019	31	28	14
2020	32	28	14
2021	33	28	14
2022	34	28	14
2023	35	27	14
2024	36	27	14
2025	36	27	14
2026*	36	27	14

*Program cycles end in 2025; 2026 values assumed the same as 2025.
Source: California Energy Commission, Demand Analysis Office, 2015.

Energy or peak load saved from dispatchable or event-based programs has traditionally been treated as a resource and, therefore, not accounted for in the demand forecast. However, the CPUC and California ISO support a “bifurcation,” or splitting in two, of such programs based on whether the resource can be integrated into the California ISO’s energy market. Event-based demand response will be divided into load-modifying (demand-side) and California ISO-

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

39 PG&E, SCE, and SDG&E *2014 Portfolio Summary Load Impact Reports*, 4/1/2015.

integrated supply-side programs. The demand forecast incorporates two types of programs, critical peak pricing and peak-time rebates, designated as load-modifying. More programs may be assigned this designation in the future.

Projected peak impacts from critical peak pricing and peak-time rebate programs, based on the IOU demand response filings, are shown in **Table 9** by IOU. Combined impacts from these two programs and nonevent-based reductions reach 146 MW for PG&E, 94 MW for SCE, and 58 MW for SDG&E by 2026.

Table 9: Estimated Demand Response Program Impacts (MW): Critical Peak Pricing and Peak-Time Rebate Programs

Year	PG&E	SCE	SDG&E
2015	83	27	31
2016	100	27	40
2017	107	50	41
2018	109	39	42
2019	109	42	42
2020	109	46	43
2021	109	50	43
2022	109	54	43
2023	110	59	44
2024	110	62	44
2025	110	67	45
2026*	110	67	45

*Program cycles end in 2025; 2026 values assumed the same as 2025.
Source: California Energy Commission, Demand Analysis Office, 2015.

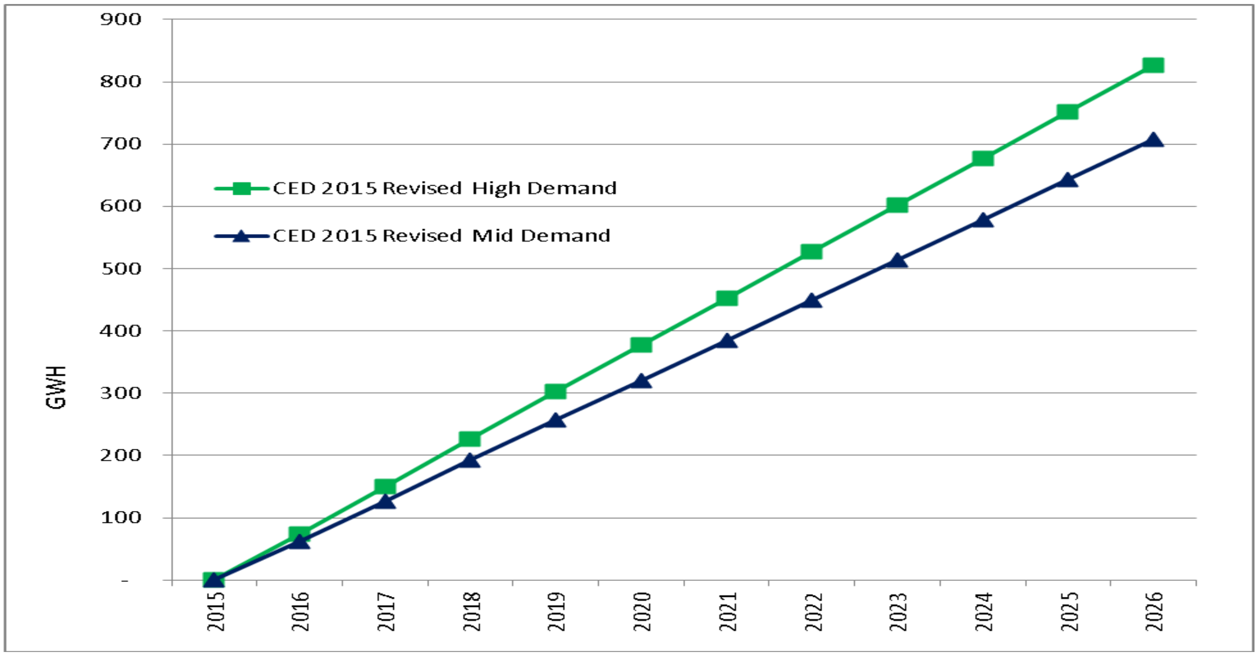
Climate Change

To estimate the potential of climate change to increase electricity consumption and peak demand, staff used temperature cases developed by the Scripps Institute of Oceanography through a set of global climate change models, where results are downscaled to 50-square-mile grids in California. From these options, staff developed high and average temperature increase cases to correspond to the high and mid demand forecast cases, respectively. The low demand case assumes no additional impacts from climate change. The two cases were applied to weather-sensitive econometric models for residential and commercial sector consumption[40] and for peak demand to estimate consumption and peak impacts for each planning area and forecasting zone. **Figure 16** and **Figure 17** show estimated climate change impacts[41] on statewide electricity consumption and peak demand, respectively.

40 Other sectors show no significant temperature sensitivity for consumption.

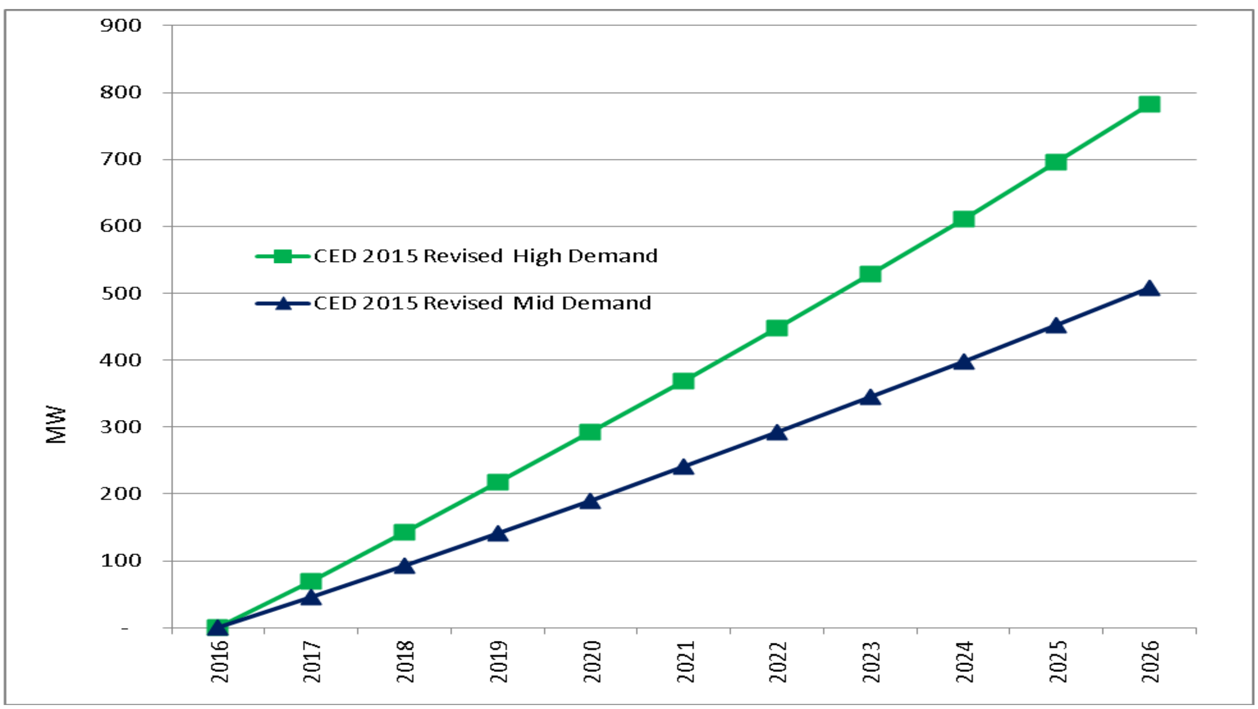
41 These should be considered incremental impacts to the extent that climate change has affected historical consumption and peak demand.

Figure 16: Estimated Impact of Climate Change on Electricity Consumption, Statewide



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

Figure 17: Estimated Impact of Climate Change on Peak Demand, Statewide



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

Table 10 shows the climate change impacts for the five major planning areas projected for 2026. Over the 10-year period, annual maximum temperatures increase in each planning area by an average of around ½ degree Fahrenheit in the mid demand case and ¾ degree in the high demand case. More details on climate change methods can be found in a 2013 Energy Commission report.[42]

Table 10: Estimated Climate Change Impacts by Planning Area, 2026

Planning Area	Energy Impacts (GWh)		Peak Impacts (MW)	
	High Demand	Mid Demand	High Demand	Mid Demand
PG&E	327	294	297	203
SCE	248	206	277	173
SDG&E	68	47	41	18
NCNC	91	82	79	54
LADWP	90	75	67	42
State Total	827	707	782	508

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

42 See Appendix A in the following report: http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf

CHAPTER 2: Efficiency

Introduction

With the state's adoption of the first *Energy Action Plan* in 2003, energy efficiency became the resource of first choice for meeting the state's future energy needs. In the last 10 years, Energy Commission staff has undertaken a major effort to improve and refine committed efficiency measurement within the baseline IEPR forecasts. In addition, beginning with *CED 2009*, IEPR forecasts have integrated AAEE savings for the IOUs to provide managed forecasts for resource planning. This chapter provides estimates for both committed efficiency and AAEE, and shows adjusted forecasts for the IOU and POU service territories.

Committed Efficiency Impacts

Energy Commission demand forecasts seek to account for efficiency and conservation that are *reasonably expected to occur*. Reasonably expected to occur initiatives have been split into two types: committed and AAEE. The *CED 2015 Revised* baseline forecasts continue that distinction, with only committed efficiency included. Committed initiatives include utility and public agency programs, codes and standards, and legislation and ordinances having final authorization, firm funding, and a design that can be readily translated into characteristics capable of being evaluated and used to estimate future impacts (for example, a package of IOU incentive programs that has been funded by CPUC order). In addition, committed impacts include price and other market effects not directly related to a specific initiative.

New Committed Savings

The *CED 2015 Revised* baseline forecast includes additional committed efficiency not included in *CEDU 2014*:

- New Title 20 appliance standards for faucets, toilets, and urinals.
- Recently enacted federal appliance standards.
- Updated federal standards for distribution transformers.
- Savings for the IOUs from programs implemented in 2015.
- Savings for the POUs from programs implemented in 2014.

The new Title 20 appliance standards, approved by the Energy Commission in May 2015, provide savings through reduced hot water usage and lower pumping requirements. The federal appliance standards encompass a variety of applications, including lighting, refrigerators, freezers, washers, boilers, and air conditioning. Both sets of standards were included in AAEE savings for *California Energy Demand 2014-2024 Final Forecast* (*CED 2013*) but are now considered committed. The Title 20 appliance standards are projected to save around 1,100 GWh and the federal standards 5,700 GWh statewide by 2026.

An additional federal regulation updates distribution transformer standards for transformers manufactured in 2016 and beyond. Staff used the DOE analysis for this rulemaking to develop an adjustment to annual energy and peak line losses in the baseline forecast.[43] The standards are actually a series of specific requirements for different transformer designs. DOE estimates that its adopted standard has 8 percent reduction in annual energy losses for liquid-immersed transformers, 13 percent for medium-voltage dry-type transformers, and 18 percent for low-voltage, dry-type transformers. National shipments data suggest the overall population of distribution transformers is 7.9 percent for liquid-immersed, 22.1 percent for medium voltage dry-type, and 69.6 percent for low-voltage dry-type transformers. This implies a weighted average 16.0 percent reduction for annual energy across all types. Estimating peak load impacts requires knowledge of the distribution of loading of distribution transformers under average and peak conditions since losses increase with the square of load. Staff used DOE engineering analyses for each of the three transformer types and an assumed peak to average loading ratio to determine that a 45.2 percent reduction in on-peak losses was a reasonable estimate of per unit transformer impacts.

DOE determined that distribution transformers have an average lifetime of 32 years, so staff phased in the per unit impact of the standard by 1/32nd for each forecast year beginning in 2016. [44] Using this method, staff estimated a statewide reduction to annual energy and peak line losses of around 250 GWh and 200 MW, respectively, by 2026.

Additional committed savings are included in *CED 2015 Revised* through a correction to calculations of Title 24 building standards impacts on existing buildings in the commercial sector going back to 2005. Staff determined that the commercial end-use model was not capturing these savings properly.[45] Properly adjusting the model resulted in around 3,000 GWh additional savings statewide by 2026.

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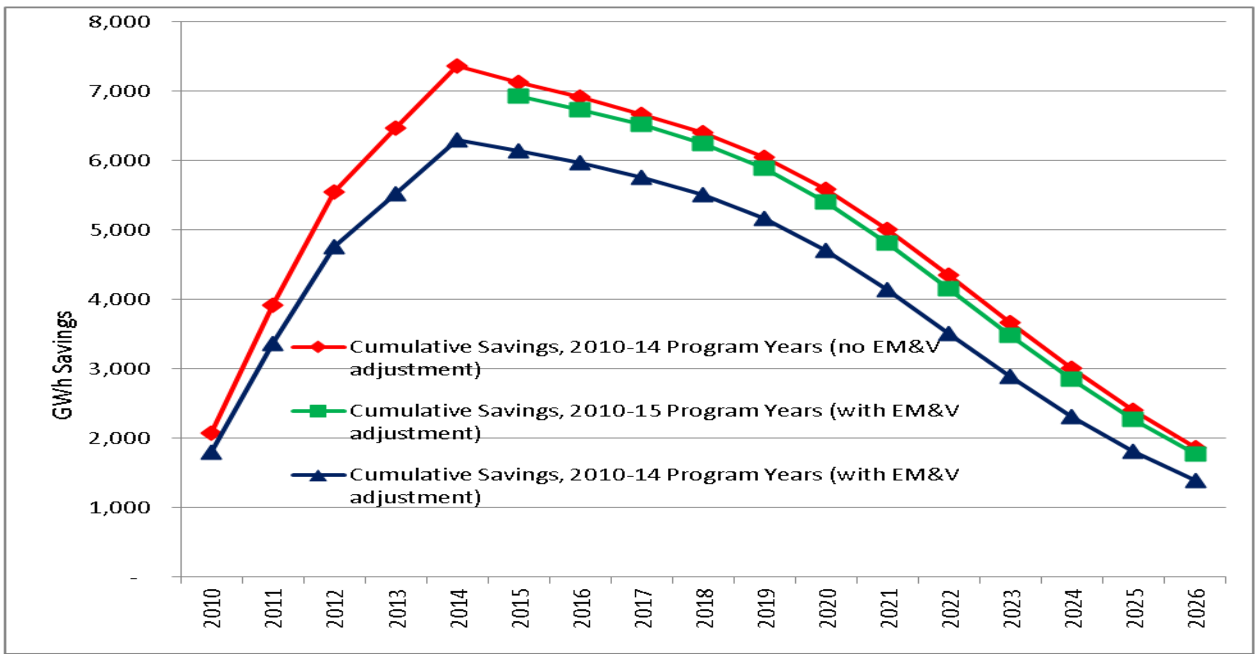
43 Estimated line losses are used in the calculation of net energy for load and peak demand.

44 Implementing this method requires knowledge of the portion of overall annual energy and peak demand losses that are at the distribution level versus the transmission level. Such data exist for the three IOUs, but not for the planning areas representing POU utilities. Staff developed a split of overall annual energy and peak demand losses to determine estimated distribution versus transmission loss factors for the non-IOU planning areas.

45 The commercial end-use model was designed to incorporate standards for new construction. Calculations for existing building savings required substantial changes to the model code.

CED 2015 Revised includes estimated committed program impacts from 2015 IOU programs and from 2014 programs administered by POUs. At the same time, staff has revised downward the estimated savings from 2010-2014 IOU programs based on the most recent CPUC evaluation, measurement, and verification (EM&V) study.[46] The study showed that actual realization of savings was below that anticipated (forecasted) for the 2010-2012 IOU programs. Staff then applied adjustment factors to 2010-2014 savings embedded in the previous forecast as well as to 2015 program savings to account for this difference. The effect of these adjustments on the 2010-2014 accumulated net (of free ridership) program savings incorporated in *CEDU 2014* is shown in **Figure 18.** The difference reaches a maximum of more than 1,000 GWh in 2015. Also shown in **Figure 18** is the effect of the addition of (adjusted) 2015 program savings, which offset the reduction in 2010-2014 savings almost exactly.

Figure 18: Adjusted IOU Efficiency Program Savings, 2010-2026

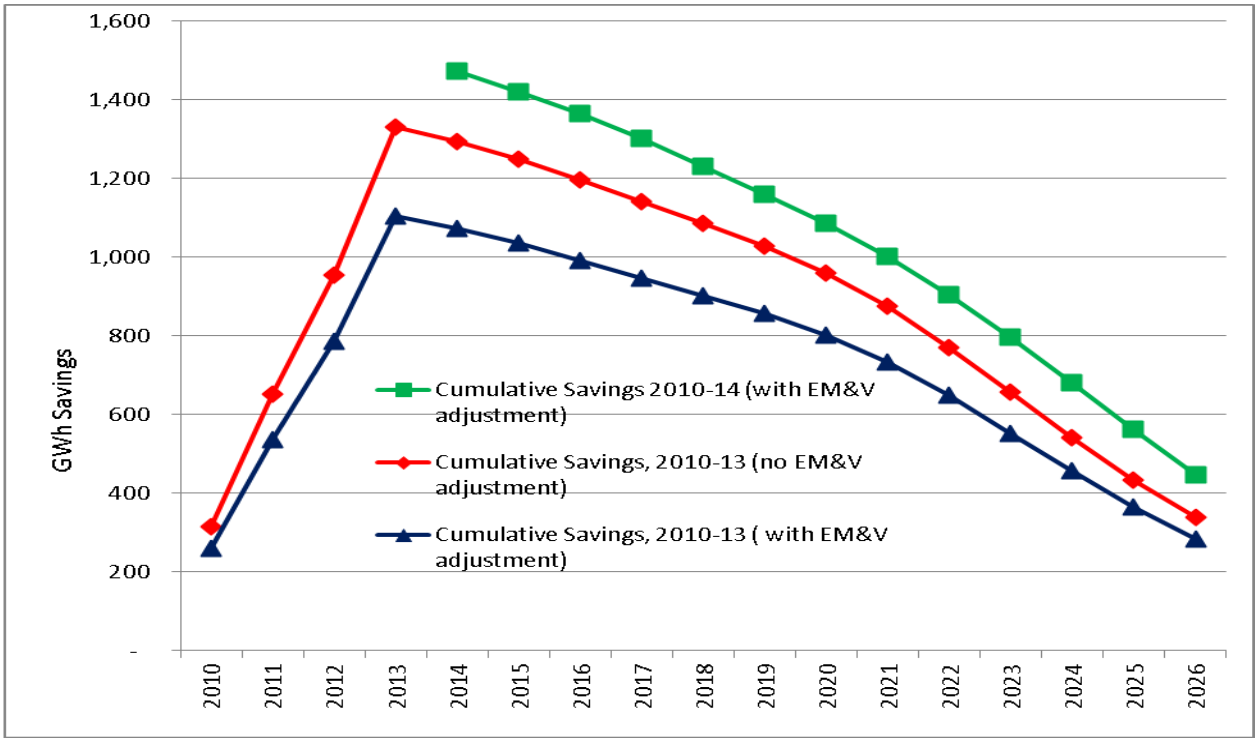


Source: California Energy Commission, Demand Analysis Office, 2015.

46 http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/Energy_Efficiency_2010-2012_Evaluation_Report.htm.

Staff applied the same adjustments to the 2010-2013 POU program impacts embedded in *CEDU 2014* as well as 2014 program year savings.[47] **Figure 19** shows the net results. In this case, 2015 programs provide enough new savings so that total POU program savings increase compared to *CEDU 2014*.

Figure 19: Adjusted POU Efficiency Program Savings, 2010-2026



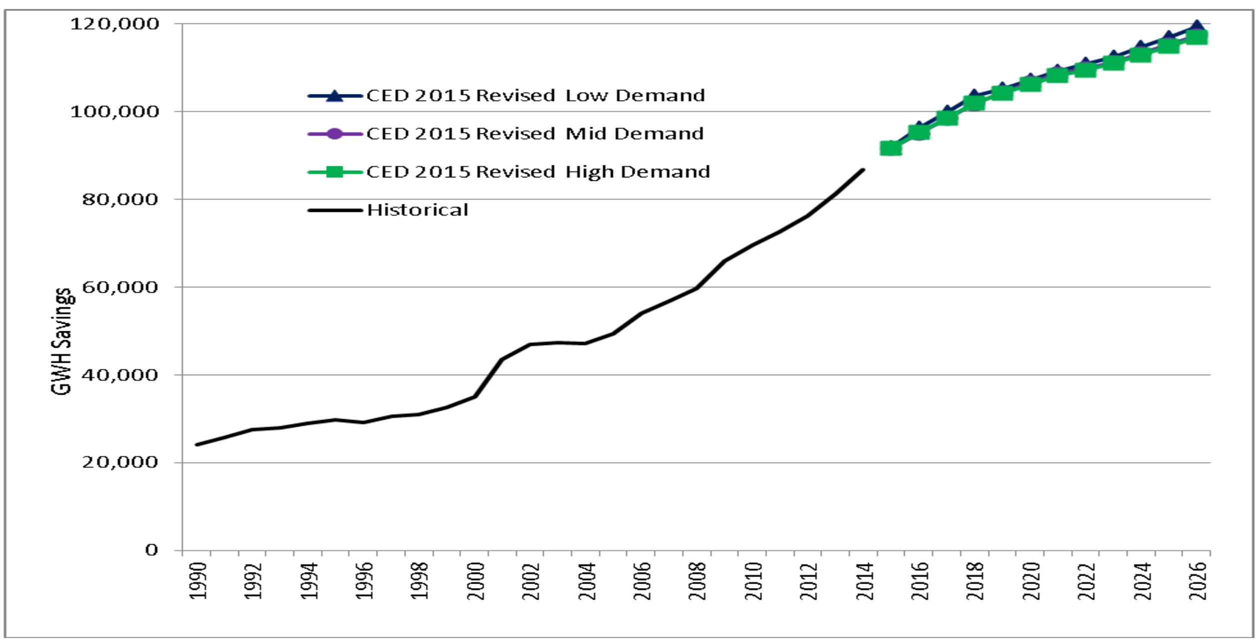
Source: California Energy Commission, Demand Analysis Office, 2015.

47 It is of course not clear that EM&V adjustments designed for the IOUs should necessarily apply to the POUs, but staff feels that the EM&V results contain the best available information for programs.

Cumulative Committed Savings

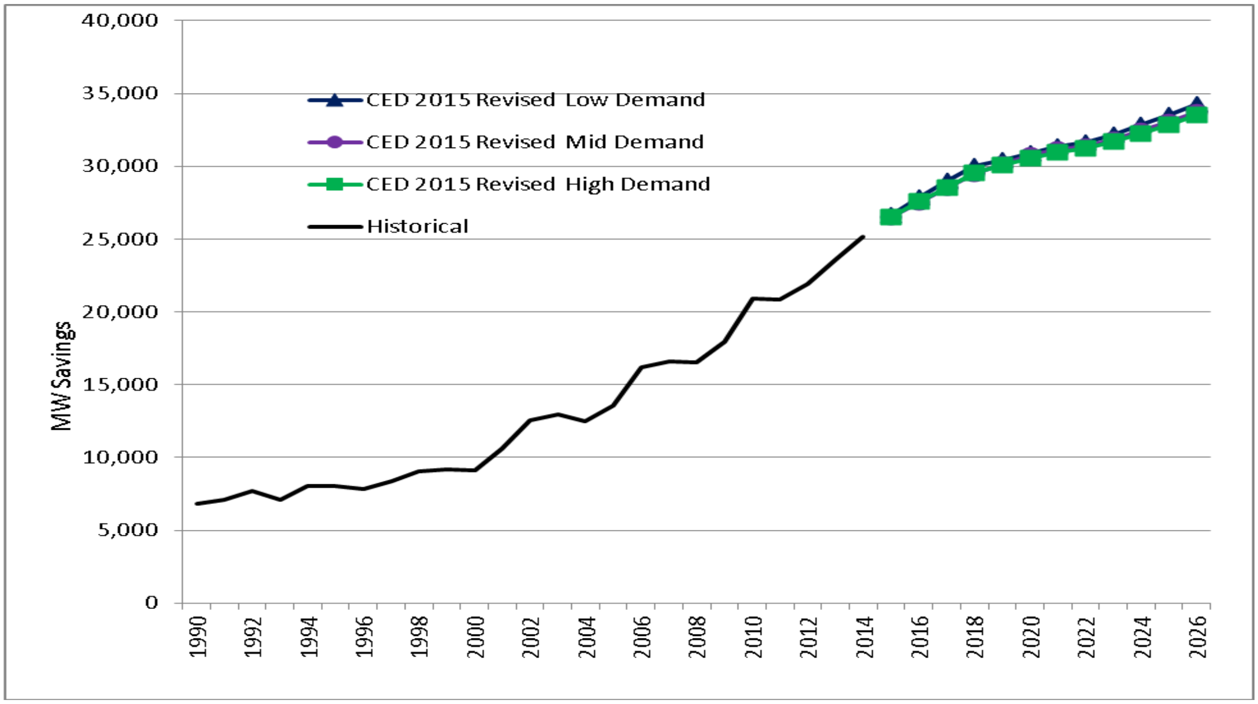
Figure 20 and **Figure 21** show staff estimates of statewide historical and projected committed electricity consumption and peak savings, respectively. Savings are measured relative to a 1975 base and incorporate the simplifying assumption that "counterfactual" demand equals measured demand plus these savings. Within the demand cases, higher demand yields more standards savings since new construction and appliance usage increase, while lower demand is associated with more program savings and higher rates (and therefore more price effects). The net result is that savings vary inversely with demand outcome, although the totals are very similar. For electricity consumption, total efficiency savings are around 87,000 GWh in 2014. Increasing rates, the addition of new programs and standards, and the continuing impacts of existing standards (as buildings and appliances turn over) push total savings to around 117,000 GWh in all three demand cases by the end of the forecast period. Peak demand savings increase to around 34,000 MW in 2026, up from around 25,000 MW in 2014. Building and appliance standards make up around 50 percent of the total in 2014 for both consumption and peak, increasing to just over 70 percent by 2026 as committed program savings decay throughout the forecast period.

Figure 20: Statewide Committed Efficiency Savings in GWh



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

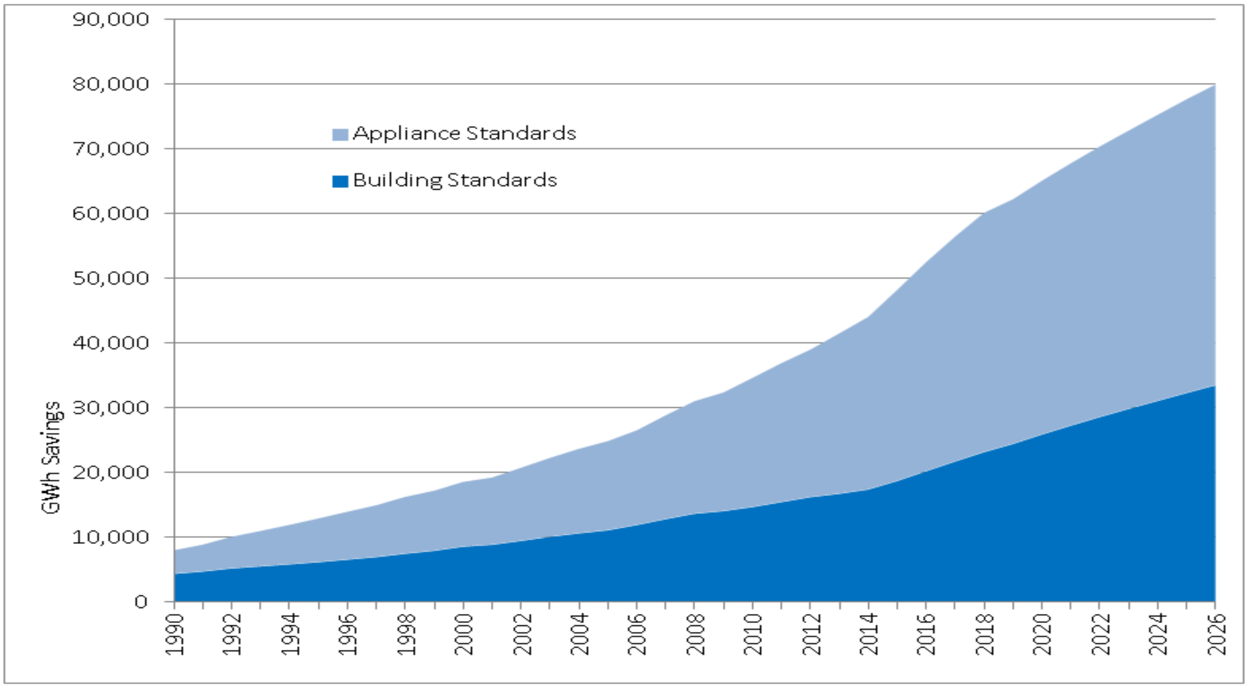
Figure 21: Statewide Committed Peak Efficiency Savings in MW



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

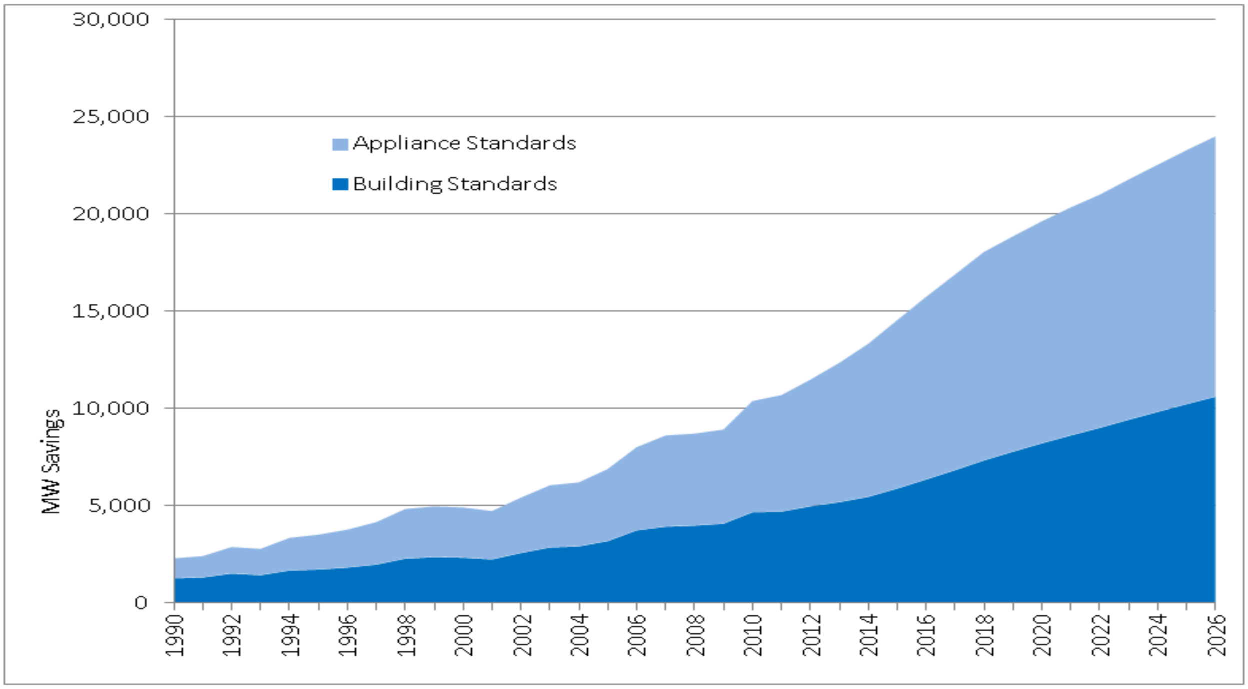
Figure 22 and **Figure 23** show estimated electricity consumption and peak savings, respectively, from appliance and building standards in the mid demand case. Forecast standards impacts increase slightly in the high demand case due to more projected commercial floor space, home additions, and appliance usage and are slightly less in the low demand case. In 2026, projected electricity standards impacts are around 4 percent above the mid case in the high demand case and 3 percent below in the low case. Savings from building standards make up around 39 percent of the total in 2014, increasing slightly to 42 percent at the end of the forecast period, reflecting growing contribution from Title 24 building standards for existing buildings**.** **Table 11** lists the standards included in the *CED 2015 Revised* baseline forecast.

Figure 22: Statewide Committed Efficiency Savings From Standards in GWh



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

Figure 23: Statewide Committed Peak Efficiency Savings From Standards in MW



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

Table 11: Committed Building and Appliance Standards Incorporated in *CED 2015 Revised*

Residential Sector	
1975 HCD Building Standards	2002 Refrigerator Standards
1978 Title 24 Residential Building Standards	2005 Title 24 Residential Building Standards
1983 Title 24 Residential Building Standards	2010 Title 24 Residential Building Standards
1991 Title 24 Residential Building Standards	2011 Television Standards
1976-82 Title 20 Appliance Standards	2011 Battery Charger Standards
1988 Federal Appliance Standards	2013 Title 24 Residential Building Standards
1990 Federal Appliance Standards	2010-14 Federal Appliance Standards
1992 Federal Appliance Standards	2015 Title 20 Appliance Standards
Nonresidential Sector	
1978 Title 24 Nonresidential Building Standards	2004 Title 20 Equipment Standards
1978 Title 20 Equipment Standards	2005 Title 24 Nonresidential Building Standards
1984 Title 24 Nonresidential Building Standards	2010 Title 24 Nonresidential Building Standards
1984 Title 20 Nonres. Equipment Standards	AB 1109 Lighting (Through Title 20)
1985-88 Title 24 Nonresidential Building	2011 Television Standards
Standards	2011 Battery Charger Standards
1992 Title 24 Nonresidential Building Standards	2013 Title 24 Nonresidential Building Standards
1998 Title 24 Nonresidential Building Standards	2010-14 Federal Appliance Standards
2001 Title 24 Nonresidential Building Standards	2015 Title 20 Appliance Standards

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

Additional Achievable Energy Efficiency: Investor-Owned Utility Service Territories

Method and Process

A demand forecast for resource planning requires a baseline forecast combined with AAEE savings; savings not yet considered committed but deemed likely to occur, including impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2015. *CED 2015 Revised* provides AAEE impacts for the IOU service territories, based on the CPUC's *2015 California Energy Efficiency Potential and Goals Study (2015 Potential Study)*.[48]

The *2015 Potential Study* estimated energy efficiency savings that could be realized through utility programs as well as codes and standards within the IOU service territories for 2006-

48 Information available at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm.

2026,[49] given current or soon-to-be-available technologies. Because many of these savings are already incorporated in the Energy Commission's *CED 2015 Revised* baseline forecast, staff needed to estimate the portion of savings from the *2015 Potential Study* not accounted for in the these forecasts. These nonoverlapping savings become AAEE savings.

Energy Commission and Navigant Consulting developed nine AAEE scenarios, with input from the Demand Analysis Working Group[50] (DAWG). These scenarios were designed to capture a range of possible outcomes determined by a host of input assumptions, with three AAEE scenarios (high, mid, and low savings) assigned to each of the three *CED 2015 Revised* demand cases. This means that the scenarios assigned to a given demand case share the same assumptions for building stock and retail rates. Energy Commission, in consultation with the Joint Agency Steering Committee[51] (JASC), subsequently pared the number of scenarios down to five, with one scenario each assigned to the high and low demand cases and three scenarios assigned to the mid demand case. These five scenarios are thus defined by the demand case and AAEE savings scenario (high, mid, or low), as follows:

- Scenario 1: High Demand-Low AAEE Savings (high-low)
- Scenario 2: Mid Demand-Low AAEE Savings (mid-low)
- Scenario 3: Mid Demand-Mid AAEE Savings (mid-mid)
- Scenario 4: Mid Demand-High AAEE Savings (mid-high)
- Scenario 5: Low Demand-High AAEE Savings (low-high)

Scenarios 1 and 5 serve as bookends designed to keep a healthy spread among the adjusted forecasts when applied to the high and low demand baseline cases. The three scenarios corresponding to the mid demand case are likely options to be applied to the *CED 2015 Revised* mid baseline forecast to yield a managed forecast or forecasts for planning purposes. Input assumptions for the five scenarios are shown in **Table 12**. These five scenarios are similar to those developed for *CED 2013*, except that the extreme cases are designed to be less so.[52]

49 The analysis begins in 2006 because results are calibrated using the CPUC's Standard Program Tracking Database, which tracks program activities from 2006-2011.

50 The Demand Analysis Working Group provides a forum for interaction among key organizations on topics related to demand forecasting and demand-side programs and policies. Membership in the Demand Analysis Working Group includes staff from the Energy Commission, the CPUC Energy Division, the Department of Ratepayer Advocates, the California IOUs, several POUs, and other interested parties, including the ARB, The Utility Reform Network, and the Natural Resources Defense Council

51 The Joint Agency Steering Committee is composed of managerial representatives from the Energy Commission, the California ISO, and the CPUC and is committed to improving coordination and process alignment across state planning processes that use the Energy Commission's demand forecast.

52 Many DAWG members felt that the high and low AAEE savings cases developed in 2013 were too improbable to be useful, so these cases included more "best estimates" than in 2013.

The following summarizes the parameters used in constructing the five scenarios. More information can be found in the *2015 Potential Study* report.[53]

1. *Incremental Costs*: Incremental costs are the difference in costs between code- or standard-level equipment and the higher-efficiency equipment under consideration. The incremental costs for efficient technologies come from the Database for Energy Efficiency Resources.

2. *Implied Discount Rate*: The implied discount rate is the effective discount rate that consumers apply when making a purchase decision; it determines the value of savings in a future period relative to the present. The implied discount rate is higher than standard discount rates used in other analyses because it is meant to account for market barriers that may affect customer decisions.

3. *Marketing and Word-of-Mouth Effects*: The base factors for market adoption are a customer's willingness to adopt and awareness of efficient technologies, which were derived from a regression analysis of technology adoptions from several studies on new technology market penetration.

4. *TRC Threshold*: The Total Resource Cost (TRC) is the primary cost-effectiveness indicator that the CPUC uses to determine funding levels and adoption thresholds for energy efficiency. The TRC test measures the net resource benefits from the perspective of all ratepayers by combining the net benefits of the program to participants and nonparticipants. A TRC threshold of 1.0 means that the benefits of a program or measure must at least equal the costs. The CPUC uses a TRC of 0.85 as a "rule of thumb," allowing programs to include marginal yet promising measures. For emerging technologies, an even lower threshold is typically used.

5. *Measure Density*: Measure density is defined as the number of units of a technology per unit area. Higher densities for efficient technologies mean more familiarity and a greater likelihood of adoption, all else equal. Specifically, measure density is categorized as follows:

    - *Baseline measure density:* the number of units of a baseline technology per home for the residential sector, or per unit of floor space for the commercial sector.

    - *Energy-efficient measure density*: the number of energy-efficient units existing per home for the residential sector, or per unit of floor space for the commercial sector.

    - *Total measure density:* typically the sum of the baseline and efficient measure density. When two or more efficient measures compete to replace the same baseline measure, then the total density is equal to the sum of the baseline density and all applicable energy-efficient technology densities.

6. *Unit Energy Savings:* Unit energy savings (UES) is the estimated difference in annual energy consumption between a measure, group of technologies, or processes and the baseline,

53 http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm.

expressed as kilowatt hour (kWh) for electric technologies and therm (thm) for gas technologies.

7. *Incentive Level*: The incentive level is the amount or percentage of incremental cost that is offset for a targeted efficient measure. While the IOUs may vary the incentive level from measure to measure, they must work within their authorized budget to maximize savings, and their incentives typically average out to be about 50 percent of the incremental cost.

The five scenarios were presented at another DAWG meeting, and stakeholders expressed concern about the relatively high peak-to-energy ratios of standards savings (much higher than in 2013). After further investigation, Navigant Consulting determined that the change was due to uncertainty factors that had been applied to standards savings in 2013 but removed for the *2015 Potential Study*. These factors were based on standards savings realization rates calculated from the 2006-2008 CPUC EM&V study and were meant to account for lower than expected savings as yielded in the study. The subsequent 2010-2012 EM&V study provided very different results in that realized standards savings appeared in general to match expected savings. Based on this result, Navigant Consulting removed the uncertainty factors in the *2015 Potential Study*. However, the 2006-2008 EM&V study pointed to significantly lower realization rates for peak demand compared to energy, and therefore removing the uncertainty factors increased peak savings much more than energy savings. After consultation with JASC, Navigant Consulting reintroduced the uncertainty factors at 50 percent of values calculated in 2013, thereby giving equal weight to the two EM&V studies.

Table 12: IOU AAEE Savings Scenarios

Demand Case	High	Mid	Mid	Mid	Low
Savings Scenario	Low (Scenario 1)	Low (Scenario 2)	Mid (Scenario 3)	High (Scenario 4)	High (Scenario 5)
Building Stock	High Demand Case	Mid Demand Case	Mid Demand Case	Mid Demand Case	Low Demand Case
Retail Prices	High Demand Case	Mid Demand Case	Mid Demand Case	Mid Demand Case	Low Demand Case
Avoided Costs	High Demand Case	Mid Demand Case	Mid Demand Case	Mid Demand Case	Low Demand Case
UES	Best Estimate UES	Best Estimate UES	Best Estimate UES	Best Estimate UES	Best Estimate UES
Incremental Costs	Best Estimate Costs	Best Estimate Costs	Best Estimate Costs	Best Estimate Costs	Best Estimate Costs
Measure Densities	Best Estimate	Best Estimate	Best Estimate	Best Estimate	Best Estimate
ET's	50% of model Results	50% of model Results	100% of model results	150% of model results	150% of model results
Incentive Level	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost
TRC Threshold	1	1	0.85	0.75	0.75
ET TRC Threshold	0.85	0.85	0.5	0.4	0.4
Word of Mouth Effect	Mid	Mid	Mid	Mid	Mid
Marketing Effect	Mid	Mid	Mid	High	High
Implied Discount Rate	Best Estimate	Best Estimate	Best Estimate	Estimate minus 20%	Estimate minus 20%
Compliance Reduction	20% Compliance Rate Reduction	20% Compliance Rate Reduction	No Compliance Reduction	No Compliance Reduction	No Compliance Reduction
Standards Compliance	No Compliance Enhancements	No Compliance Enhancements	No Compliance Enhancements	Compliance Enhancements	Compliance Enhancements
Title 24	2016	2016	2016, 2019, 2022	2016, 2019, 2022	2016, 2019, 2022
Title 20	2016	2016	2016, 2018-2022	2016, 2018-2022	2016, 2018-2022
Federal Standards	On-the-books	On-the-books	On-the-books, Expected	On-the-books, Expected, Possible	On-the-books, Expected, Possible

Sources: Navigant Consulting and California Energy Commission, Demand Analysis Office, 2015

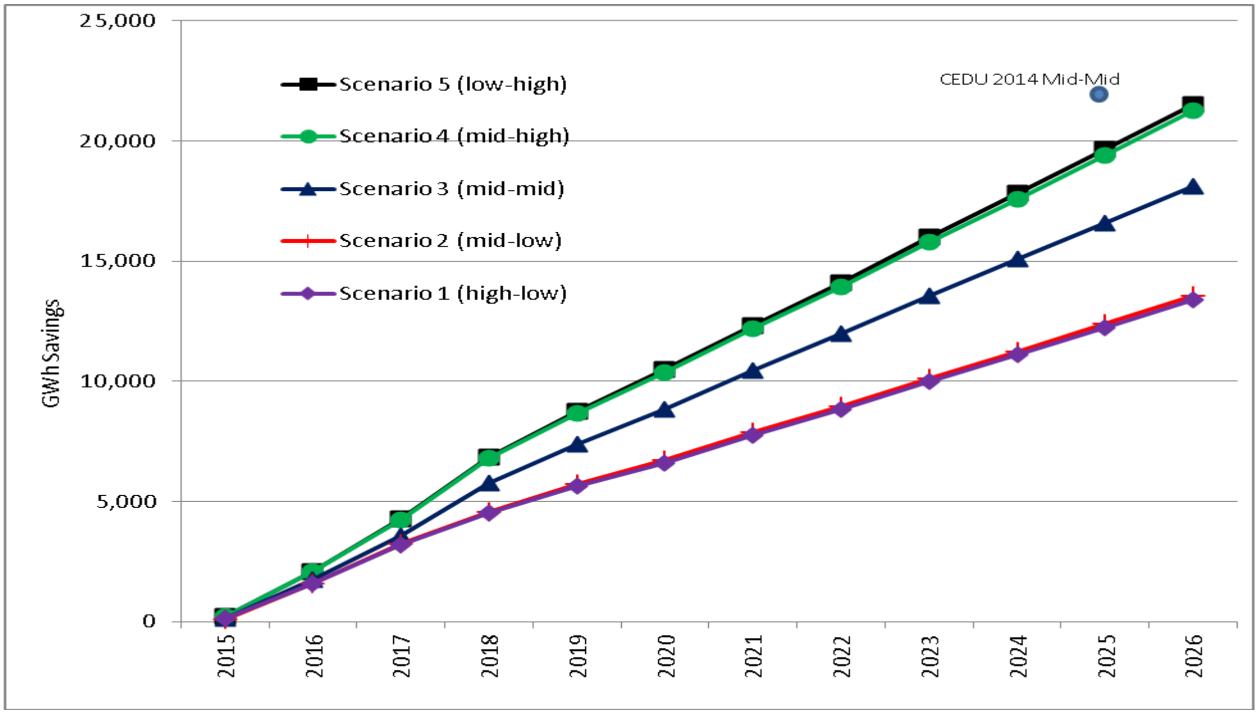
Summary of Results

This section summarizes AAEE projections for the IOUs. Spreadsheets with more detail for each service territory are posted with the report.[54]

Figure 24 and **Figure 25** show estimated AAEE savings by scenario for the IOUs combined for energy and peak demand, respectively. AAEE savings begin in 2015 because 2014 was the last recorded historical year for consumption in *CED 2015 Revised*. By 2026, AAEE savings reach roughly 18,000 GWh energy savings and about 4,500 MW of peak savings in Scenario 3 (mid-mid). The high savings scenarios reach around 21,500 GWh and more than 5,000 MW in 2026, while projected totals in the low savings scenarios are about 13,500 GWh and 3,300 MW. Totals for the low-high and mid-high scenarios are very similar, as are the high-low and mid-low because the impacts of building stock and electricity rates work in opposite directions and nearly offset each other. **Figure 24** and **Figure 25** also show AAEE savings in 2025 for the Mid Demand Mid AAEE Savings case from *CEDU 2014*, well above the new mid-mid scenarios for GWh and MW. With the same set of input assumptions, AAEE savings are lower compared to *CEDU 2014* because some standards previously included as AAEE are now committed savings. In addition, program savings in the *2015 Potential Study* are generally lower compared to 2013, reflecting downward adjustments to realization rates based on the 2010-2012 EM&V study.

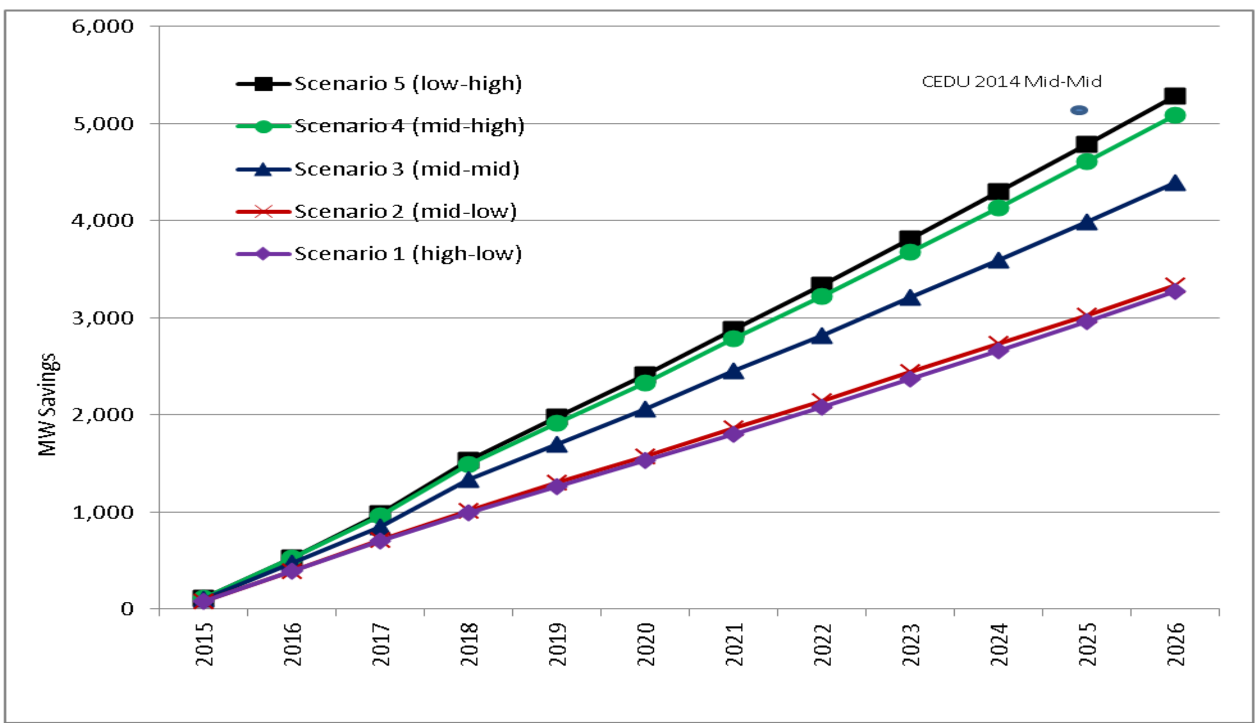
54 http://www.energy.ca.gov/2015_energypolicy/documents/index.html#12172015.

Figure 24: AAEE Energy Savings (GWh) by Scenario, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2015

Figure 25: AAEE Savings for Peak Demand (MW) by Scenario, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2015

Table 13 shows combined IOU AAEE savings by type (program measures and standards) projected for the mid-mid scenario. In 2015, the only program measure GWh savings come from behavioral programs. (Navigant Consulting does not provide peak savings for this category.) The proportion of savings attributed to standards is higher for peak MW compared to energy because of a relatively high peak-to-energy ratio for future Title 24 building standards, as well as for future federal standards for air conditioners. **Table 14** provides the totals by type in 2026 for all five scenarios. The standards proportion of savings is lowest in the low savings scenarios (1 and 2) since a smaller number of standards updates are included.

Table 13: AAEE Savings by Type, Combined IOUs, Scenario 3 (Mid-Mid)

Year	GWh			MW		
	Program Measures	Standards	Total	Program Measures	Standards	Total
2015	22	115	137	-	107	107
2016	1,449	302	1,751	231	241	472
2017	2,938	643	3,581	476	377	854
2018	3,960	1,829	5,789	663	669	1,332
2019	4,796	2,589	7,385	828	874	1,702
2020	5,505	3,333	8,838	978	1,086	2,064
2021	6,369	4,064	10,432	1,145	1,306	2,451
2022	7,166	4,800	11,966	1,295	1,526	2,821
2023	8,065	5,488	13,554	1,471	1,738	3,209
2024	9,015	6,061	15,076	1,663	1,934	3,597
2025	10,013	6,587	16,600	1,868	2,123	3,991
2026	11,069	7,058	18,128	2,086	2,305	4,390

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

Table 14: Combined IOU AAEE Savings by Type, 2026

		Scenario 1 (high-low)	**Scenario 2 (mid-low)**	**Scenario 3 (mid-mid)**	**Scenario 4 (mid-high)**	**Scenario 5 (low-high)**
GWh	Program Measures	9,770	9,912	11,069	13,147	13,414
	Standards	3,644	3,644	7,058	8,105	8,105
	Total	13,414	13,556	18,128	21,251	21,519
MW	Program Measures	1,797	1,859	2,086	2,580	2,777
	Standards	1,472	1,472	2,305	2,503	2,503
	Total	3,270	3,331	4,390	5,083	5,280

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

Table 15 shows combined IOU AAEE savings for the mid-mid scenario by sector in selected years. The distribution reflects Navigant Consulting's conclusion that the largest share of remaining energy efficiency potential resides in the commercial sector. For peak demand, residential savings are higher than commercial because the residential sector tends to have higher peak demand relative to average load. **Table 16** provides savings by sector for all scenarios in 2026.

Table 15: Combined IOU AAEE Savings by Sector, Mid-Mid Scenario

	Sector	2016	2018	2020	2022	2024	2026
GWh	Agricultural	51	155	265	378	492	610
	Commercial	704	2,702	4,505	6,233	8,046	9,946
	Industrial	95	385	673	952	1,224	1,491
	Mining	11	29	43	52	59	65
	Residential	854	2,406	3,165	4,110	4,978	5,713
	Street Lighting	35	112	187	242	277	303
	All Sectors	1,750	5,789	8,838	11,966	15,076	18,128
MW	Agricultural	3	10	17	24	31	38
	Commercial	128	479	802	1,142	1,538	1,972
	Industrial	9	29	49	69	88	106
	Mining	1	3	5	6	7	7
	Residential	331	811	1,192	1,581	1,934	2,267
	Street Lighting	--	--	--	--	--	--
	All Sectors	472	1,332	2,064	2,821	3,597	4,390

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

Table 16: Combined IOU AAEE Savings by Sector, 2026

	Sector	Scenario 1 (high-low)	Scenario 2 (mid-low)	Scenario 3 (mid-mid)	Scenario 4 (mid-high)	Scenario 5 (low-high)
GWh	Agricultural	601	602	610	610	611
	Commercial	7,827	7,903	9,946	11,816	12,009
	Industrial	1,383	1,385	1,491	1,645	1,646
	Mining	64	65	65	65	66
	Residential	3,383	3,447	5,713	6,670	6,746
	Street Lighting	155	154	303	444	441
	All Sectors	13,414	13,556	18,128	21,251	21,519
MW	Agricultural	38	38	38	38	38
	Commercial	1,560	1,596	1,972	2,425	2,503
	Industrial	103	103	106	111	111
	Mining	7	7	7	7	7
	Residential	1,561	1,587	2,267	2,501	2,620
	Street Lighting	--	--	--	--	--
	All Sectors	3,270	3,331	4,390	5,083	5,280

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

Table 17 shows the savings impact of emerging technologies across all scenarios for the combined IOUs in selected years. This category encompasses technologies that are not yet available in today's market or at very low penetration levels but expected to become commercially viable during the forecast period. Most of the savings from emerging technologies comes from light-emitting diode (LED) lighting (including street lighting) and new washer, dryer, and air-conditioning technologies. As indicated in **Table 12**, assumptions for emerging technologies varied significantly among the scenarios, both in terms of TRC threshold and adjustments to the Navigant Consulting model results. For GWh, the percentage of total AAEE savings provided by emerging technologies ranges from 6 percent in Scenario 1 (high-low) to 16 percent in Scenario 5 (low-high).

Table 17: Combined IOU Emerging Technology Savings by Scenario

	Year	**Scenario 1 (high-low)**	**Scenario 2 (mid-low)**	**Scenario 3 (mid-mid)**	**Scenario 4 (mid-high)**	**Scenario 5 (low-high)**
GWh	2016	52	54	118	206	206
	2018	160	170	373	651	655
	2020	271	292	637	1,108	1,137
	2022	384	420	910	1,570	1,629
	2024	576	631	1,347	2,320	2,412
	2026	813	890	1,882	3,226	3,360
MW	2015	6	6	15	28	29
	2018	18	20	48	89	96
	2020	31	35	83	154	177
	2022	45	52	122	225	273
	2024	75	87	195	355	436
	2026	114	131	288	518	645

Source: California Energy Commission, Demand Analysis Office, 2015

Table 18 provides AAEE savings by IOU in the mid-mid savings scenario for selected years. Total savings are generally a function of total sales or peak demand in each IOU, although electricity savings percentages (relative to sales or peak) are slightly lower for SDG&E because of less potential in the agricultural and industrial sectors. **Table 19** provides savings by IOU by scenario for 2026.

Table 18: AAEE Savings by IOU, Mid-Mid Scenario

	Utility	**2016**	**2018**	**2020**	**2022**	**2024**	**2026**
GWh	PG&E	722	2,407	3,679	5,004	6,300	7,572
	SCE	819	2,736	4,206	5,690	7,181	8,652
	SDG&E	208	646	953	1,272	1,596	1,903
	Total IOU	1,750	5,789	8,838	11,966	15,076	18,128
MW	PG&E	195	545	843	1,156	1,480	1,811
	SCE	227	645	1,006	1,372	1,746	2,128
	SDG&E	51	141	216	293	371	451
	Total IOU	472	1,332	2,064	2,821	3,597	4,390

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

Table 19: AAEE Savings by IOU and Scenario, 2026

	Utility	**Scenario 1 (high-low)**	**Scenario 2 (mid-low)**	**Scenario 3 (mid-mid)**	**Scenario 4 (mid-high)**	**Scenario 5 (low-high)**
GWh	PG&E	5,466	5,597	7,572	8,830	8,994
	SCE	6,535	6,546	8,652	10,202	10,297
	SDG&E	1,412	1,413	1,903	2,220	2,228
	Total IOU	13,414	13,556	18,128	21,251	21,519
MW	PG&E	1,299	1,329	1,811	2,097	2,226
	SCE	1,631	1,658	2,128	2,466	2,522
	SDG&E	340	344	451	520	532
	Total IOU	3,270	3,331	4,390	5,083	5,280

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

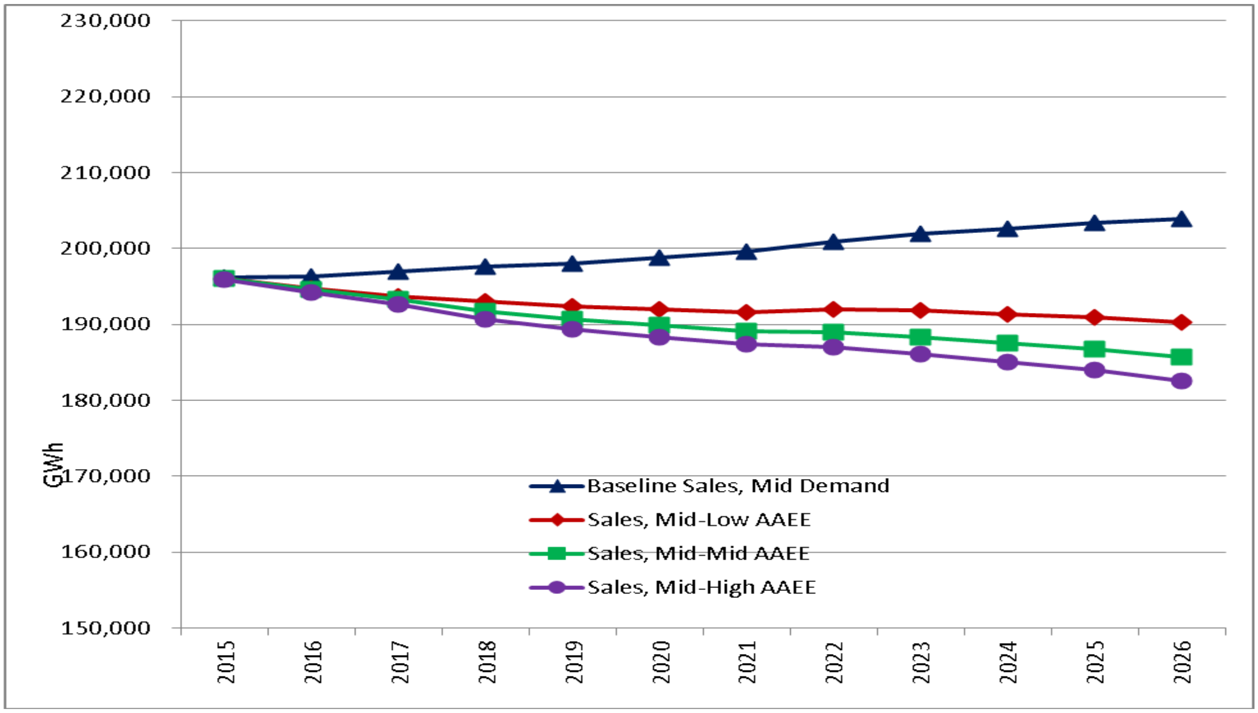
Adjusted Forecasts for Investor-Owned Utility Service Territories

Staff develops the baseline forecasts for consumption, sales, and peak demand at the planning-area level. However, the AAEE savings presented in this chapter are meant to be applied to service territories, which are a subset of the associated planning areas in the case of PG&E and SCE. To develop baseline forecasts for these service territories, staff applies a similar rate of growth as the planning areas to service territory sales and peak in the last historical year (2014 and 2015). Adjusted forecasts presented in this section are for the three IOU service territories combined. Forecasts for the individual service territories with and without AAEE adjustments are provided in the planning area chapters in Volume 2 of this report and in the 1.1c and 1.5 forms accompanying this report.[55]

Figure 26 and **Figure 27** show the effects of the estimated mid-low, mid-mid, and mid-high AAEE savings scenarios on *CED 2015 Revised* mid baseline demand for the combined IOU service territories for electricity sales and noncoincident peak demand. AAEE peak impacts are adjusted upward to account for line losses. Adjusted electricity sales and peak demand decrease in all three AAEE scenarios, reflecting the lower baseline sales and peak forecasts in *CED 2015 Revised*.

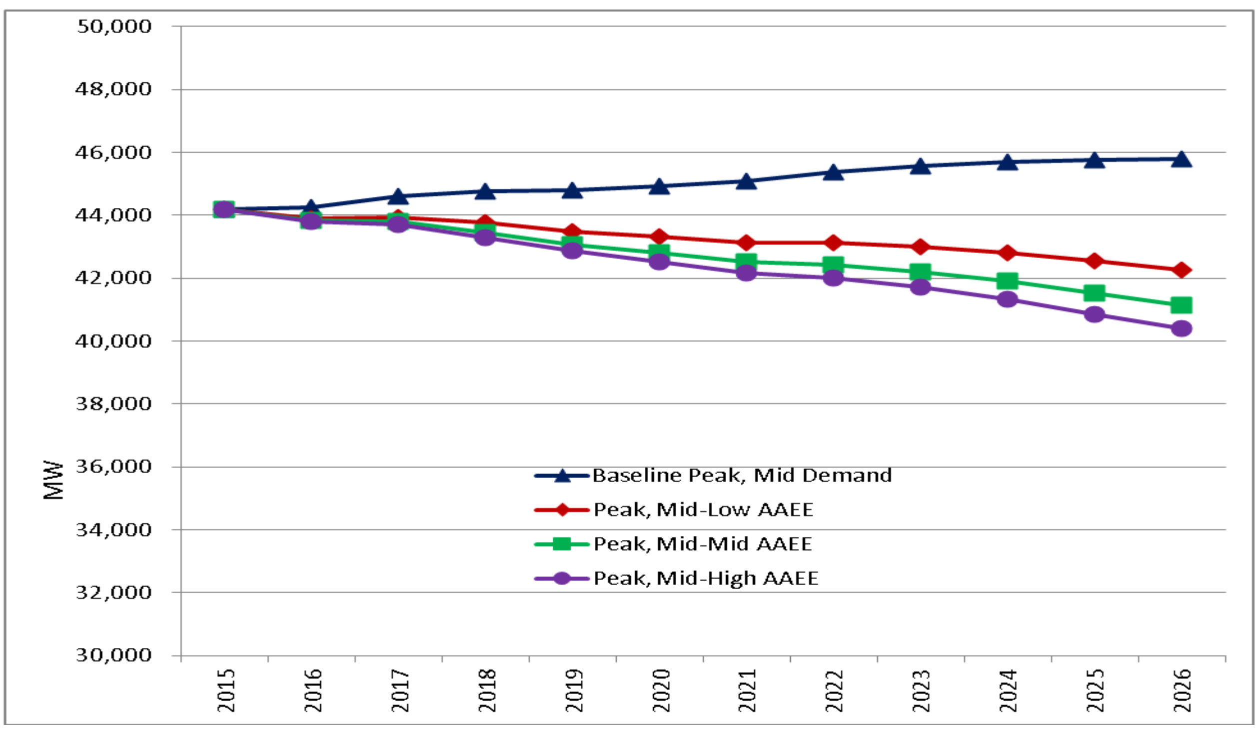
55 http://www.energy.ca.gov/2015_energypolicy/documents/index.html#12172015.

Figure 26: Mid Baseline Demand and Adjusted Sales, Combined IOU Service Territories



Source: California Energy Commission, Demand Analysis Office, 2015

Figure 27: Mid Baseline Demand and Adjusted Peaks, Combined IOU Service Territories

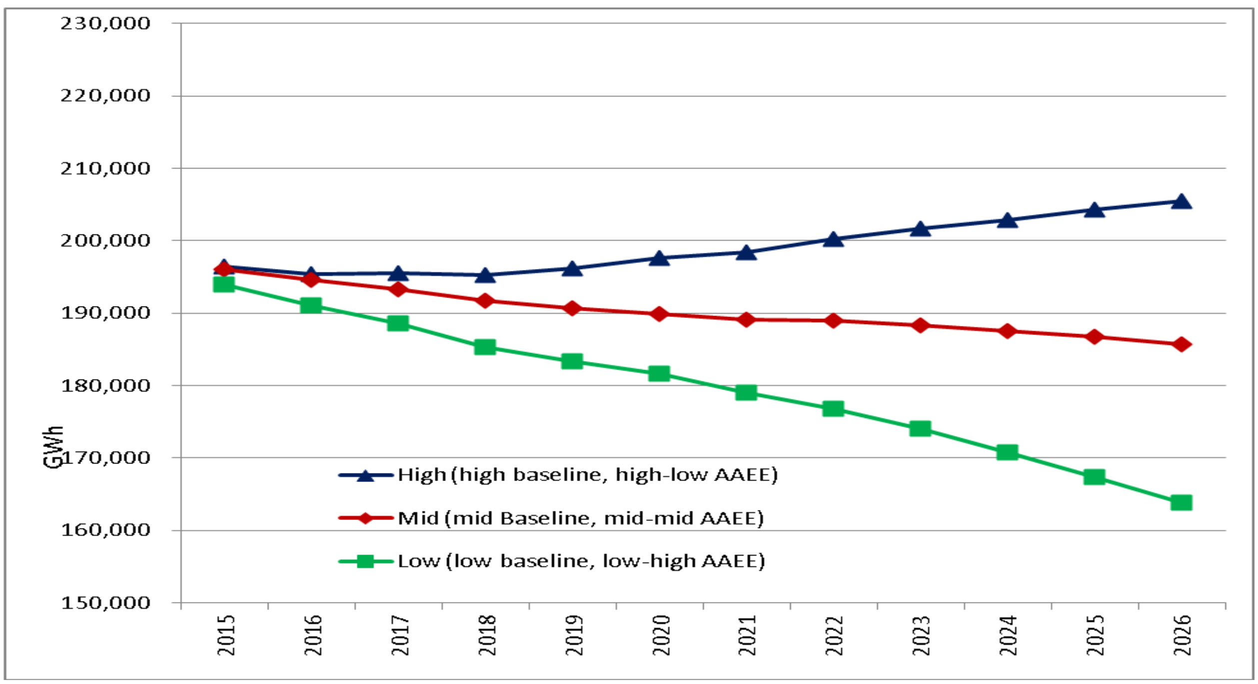


Source: California Energy Commission, Demand Analysis Office, 2015

Figure 28 and Figure 29 show the *CED 2015 Revised* high demand, mid demand, and low demand baseline forecasts when adjusted by high-low AAEE savings, mid-mid savings, and low-high savings, respectively, for the combined IOU service territories. Only the adjusted high demand case shows increases in sales and peak over the forecast period. Relative to the baseline forecasts, electricity sales in 2026 are reduced by 6.1 percent, 8.9 percent, and 11.6 percent for the high, low, and mid demand cases, respectively. Peak demand is reduced by 7.1 percent, 10.2 percent, and 13.3 percent, respectively, in 2026.

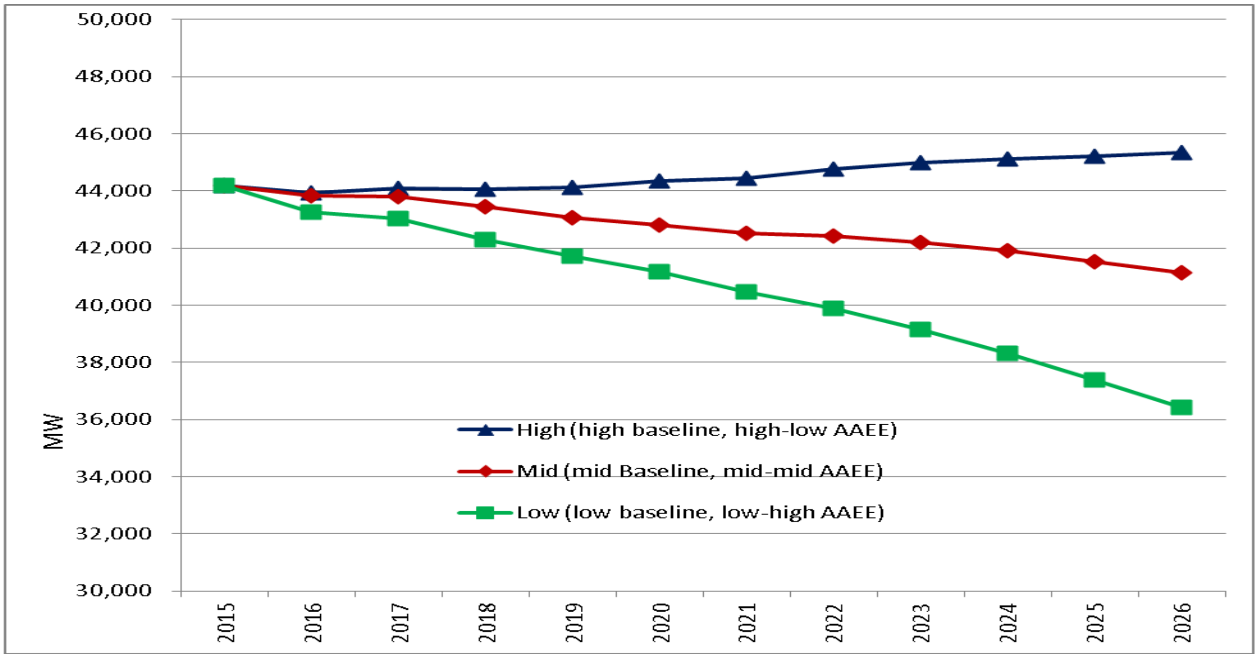
The adjusted service territory forecasts provided in this report constitute options to form the basis for an adjusted, or managed, forecast to be used for planning purposes in Energy Commission, CPUC, and California ISO proceedings. The choice of baseline case and AAEE scenario to use for this purpose will be documented in the *2015 IEPR* to be adopted in February 2016.

Figure 28: Adjusted Demand Cases for Electricity Sales, Combined IOU Service Territories



Source: California Energy Commission, Demand Analysis Office, 2015

Figure 29: Adjusted Demand Cases for Peak, Combined IOU Service Territories



Source: California Energy Commission, Demand Analysis Office, 2015

Additional Achievable Energy Efficiency: Publicly Owned Utilities

Although POUs are not required to use the IEPR demand forecasts for resource planning, the Energy Commission undertakes statewide analyses for renewables and transmission planning. In this report, staff has made the first attempt to provide adjusted, or managed, forecasts for POUs. For *CED 2015 Revised*, staff includes AAEE estimates for LADWP and SMUD, the two largest POUs. Future forecasts will include AAEE estimates for as many additional POUs as can provide detailed efficiency projections (as opposed to simply assuming efficiency goals are met) spanning the next 10 years.

Method

For future appliance and building standards, staff used the same basic method as Navigant Consulting in estimating savings within a given scenario. Estimated statewide savings from state and federal sources were downscaled to the LADWP and SMUD service territories at the sector level. For building standards, commercial floor space and number of household projections (relative to statewide totals) were used to downscale building standards in the commercial and residential sectors, respectively. For appliance standards, statewide savings were downscaled based on projected sector electricity usage in the service territory versus the state. These calculations provided high, mid, and low scenarios consistent with Navigant Consulting's estimates for the IOUs, as well as consistent with *CED 2015 Revised* baseline demand case assumptions.

For programs, staff consulted with efficiency experts for the two utilities to obtain the latest savings projections by end use and sector being used in their official planning forecasts. Similar to the IOUs, these projections derive from potential studies for each utility. Staff also required assistance from the utilities in transforming the estimates to incremental savings relative to 2014, since the baseline *CED 2015 Revised* forecast covers (committed) program savings through this year. In the case of LADWP, detailed estimates were available only through 2020; staff held total savings constant at 2020 accumulated levels through 2026, which is likely a conservative measurement for the later years. Staff discounted the savings slightly by applying the realization rates from the CPUC 2010-2012 EM&V study at the end-use level, using SCE rates for LADWP and PG&E rates for SMUD. Staff did not attempt to develop alternative scenarios for programs, so scenario variation comes from standards savings only.

Scenarios are then defined as follows:

- Scenario 1: High Demand-Low AAEE Savings (high-low)
- Scenario 2: Mid Demand-Mid AAEE Savings (mid-mid)
- Scenario 3: Low Demand-High AAEE Savings (low-high)

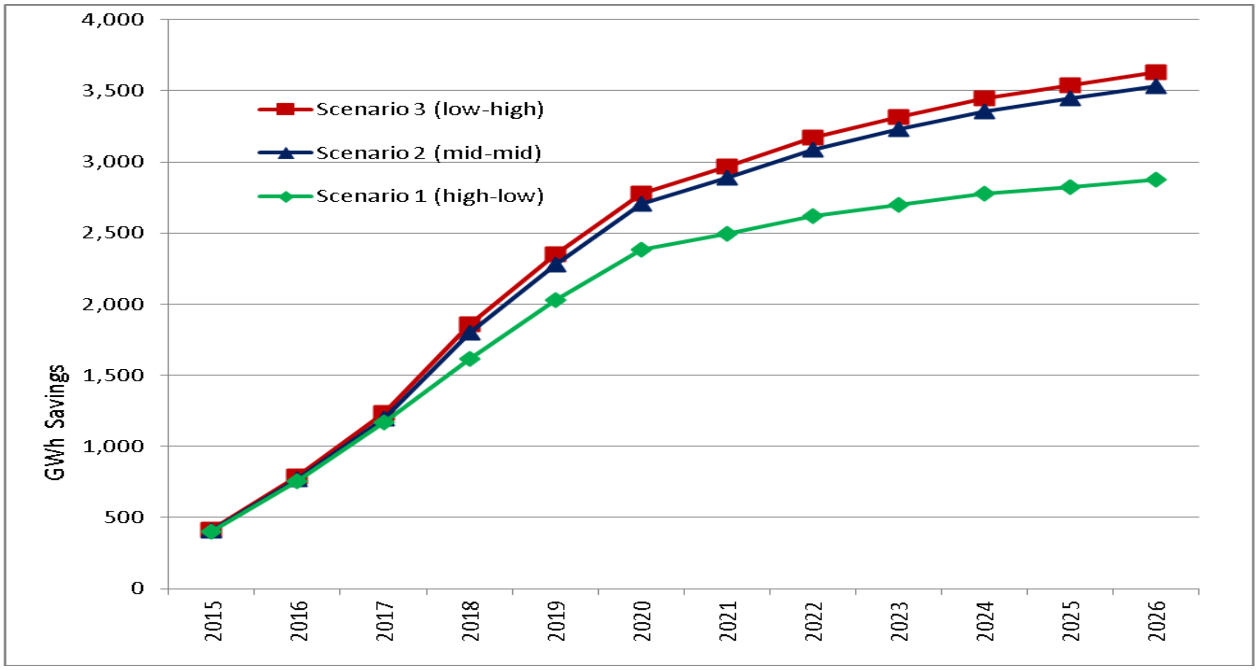
Summary of Results

This section summarizes AAEE projections for LADWP and SMUD. Spreadsheets with more detail for each utility are posted with this report.[56]

Figure 30 and **Figure 31** show estimated AAEE savings by scenario for LADWP and SMUD combined for energy and noncoincident peak demand, respectively. Savings reach around 3,500 GWh and more than 900 MW in the mid and high savings scenarios and a little under 3,000 GWh and 800 MW in the low savings scenario. The mid and high savings scenarios are similar since standards savings does not differ significantly. The kink in each of the curves in 2020 reflects the assumption of constant rather than growing program savings for LADWP after this year.

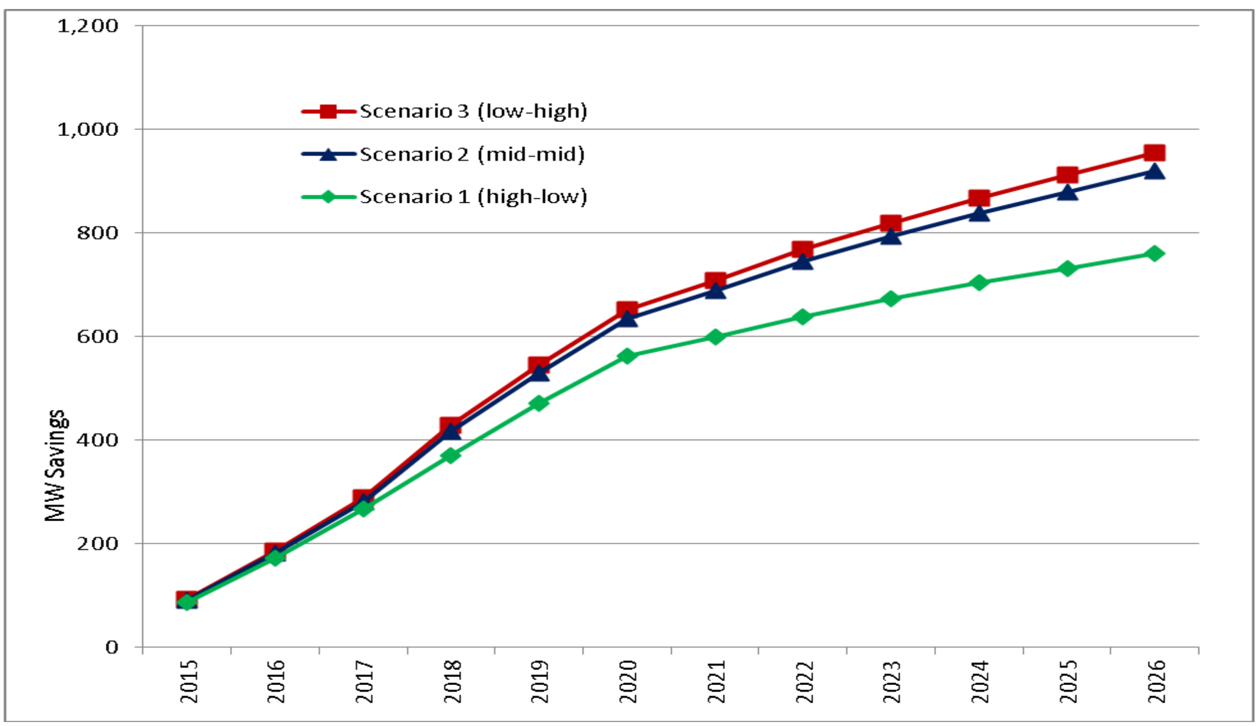
56 http://www.energy.ca.gov/2015_energypolicy/documents/index.html#12172015.

Figure 30: AAEE Energy Scenarios (GWh), Combined POUs



Source: California Energy Commission, Demand Analysis Office, 2015

Figure 31: AAEE Peak Demand Cases (MW), Combined POUs



Source: California Energy Commission, Demand Analysis Office, 2015

Table 20 shows combined POU AAEE savings by type in the mid-mid scenario. The peak impacts of standards relative to the energy impacts reflect high peak-to-energy ratios estimated for Title 24 building standards and federal standards for air conditioners. **Table 21** provides the totals by type in 2026 for all three scenarios.

Table 20: AAEE Savings by Type, Combined POUs, Mid-Mid Scenario

Year	GWh			MW		
	Program Measures	Standards	Total	Program Measures	Standards	Total
2015	384	22	406	71	20	91
2016	712	58	769	135	46	181
2017	1,075	121	1,196	210	72	281
2018	1,447	350	1,798	288	128	416
2019	1,785	496	2,280	363	167	530
2020	2,064	639	2,703	427	208	635
2021	2,112	779	2,890	440	250	690
2022	2,169	919	3,087	454	291	746
2023	2,179	1,049	3,228	463	331	794
2024	2,199	1,158	3,357	471	368	839
2025	2,188	1,258	3,446	475	404	879
2026	2,184	1,348	3,533	481	439	919

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

Table 21: Combined POU AAEE Savings by Type, 2026

		Scenario 1 (high-low)	**Scenario 2 (mid-mid)**	**Scenario 3 (low-high)**
GWh	Program Measures	2,184	2,184	2,184
	Standards	689	1,348	1,446
	Total	2,873	3,533	3,631
MW	Program Measures	481	481	481
	Standards	279	439	474
	Total	760	919	955

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

Table 22 shows combined POU AAEE savings for the mid-mid scenario by sector in selected years. Similar to the IOUs, energy savings are highest in the commercial sector and peak savings in the residential. **Table 23** provides savings by sector for all scenarios in 2026.

Table 22: Combined POU AAEE Savings by Sector, Mid-Mid Scenario

	Sector	2016	2018	2020	2022	2024	2026
GWh	Commercial	505	1,142	1,661	1,826	1,991	2,069
	Industrial	0	13	27	40	52	64
	Residential	264	642	1,015	1,222	1,314	1,400
	All Sectors	769	1,798	2,703	3,087	3,357	3,533
MW	Commercial	94	212	309	329	350	365
	Industrial	0	0	1	1	2	2
	Residential	87	203	325	415	487	553
	All Sectors	181	416	635	746	839	919

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

Table 23: Combined POU AAEE Savings by Sector, 2026

	Sector	Scenario 1 (high-low)	Scenario 2 (mid-mid)	Scenario 3 (low-high)
GWh	Commercial	1,781	2,069	2,118
	Industrial	50	64	74
	Residential	1,042	1,400	1,438
	All Sectors	2,873	3,533	3,631
MW	Commercial	323	365	374
	Industrial	2	2	2
	Residential	435	553	578
	All Sectors	760	919	955

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

Table 24 provides AAEE savings by POU in the mid-mid savings scenario for selected years. As a percentage of total sales and peak demand, savings are roughly equivalent for the two utilities. **Table 25** provides savings by POU by scenario for 2026.

Table 24: AAEE Savings by POU, Mid-Mid Scenario

	Utility	2016	2018	2020	2022	2024	2026
GWh	LADWP	476	1,199	1,892	2,082	2,246	2,378
	SMUD	293	599	811	1,005	1,111	1,155
	Total	769	1,798	2,703	3,087	3,357	3,533
MW	LADWP	123	294	458	513	564	610
	SMUD	58	122	177	233	275	309
	Total	181	416	635	746	839	919

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

Table 25: AAEE Savings by POU and Scenario, 2026

	Utility	Scenario 1 (high-low)	Scenario 2 (mid-mid)	Scenario 3 (low-high)
GWh	LADWP	1,935	2,378	2,441
	SMUD	938	1,155	1,190
	Total	2,873	3,533	3,631
MW	LADWP	505	610	632
	SMUD	255	309	323
	Total	760	919	955

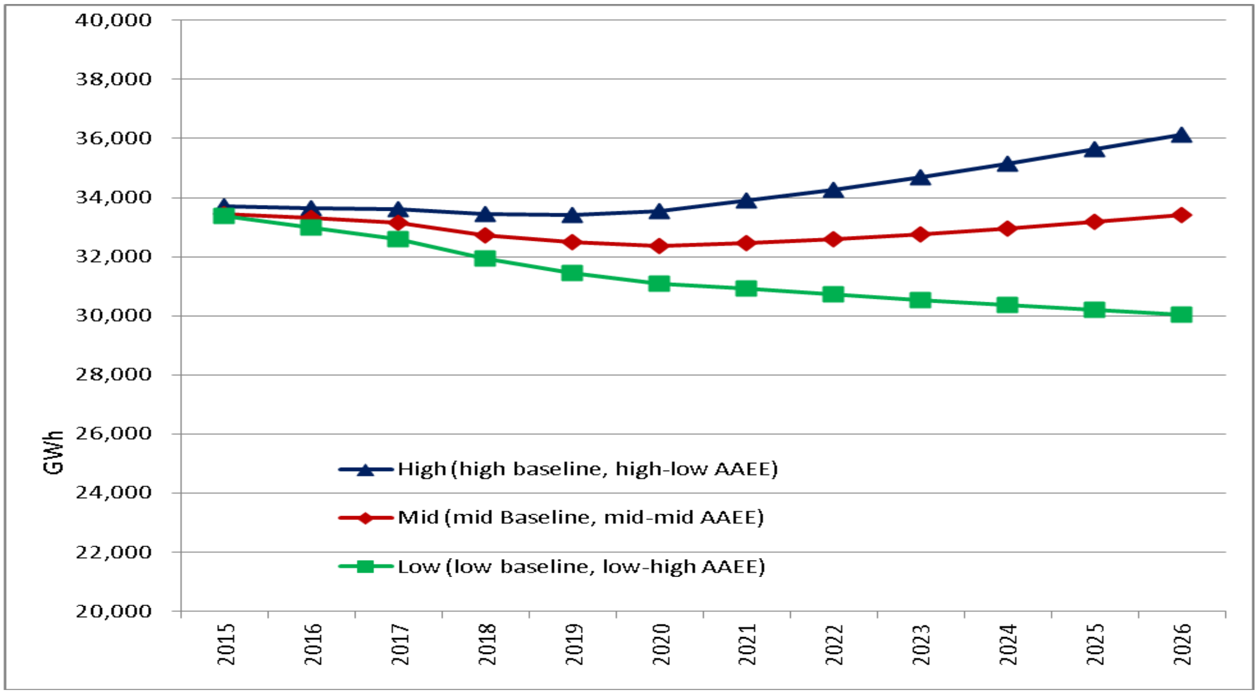
NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2015

Adjusted Forecasts for Publicly Owned Utility Service Territories

Figure 32 and Figure 33 show the *CED 2015 Revised* high demand, mid demand, and low demand baseline forecasts for sales and noncoincident peak demand when adjusted by high-low AAEE savings, mid-mid savings, and low-high savings, respectively, for the combined LADWP and SMUD service territories. Unlike the IOU results, adjusted mid demand case sales and peak demand increase over the second half of the forecasting period because LADWP program savings are held constant for 2020 and beyond. Relative to the baseline forecasts, electricity sales in 2026 are reduced by 7.4 percent, 9.6 percent, and 10.8 percent for the high, low, and mid demand cases, respectively. Peak demand is reduced by 7.3 percent, 9.4 percent, and 10.7 percent, respectively, in 2026. Adjusted forecasts presented in this section are for the two POU service territories combined. Forecasts for the two service territories with and without AAEE adjustments are provided in the planning area chapters in Volume 2 of this report and in the 1.1c and 1.5 forms accompanying this report.[57]

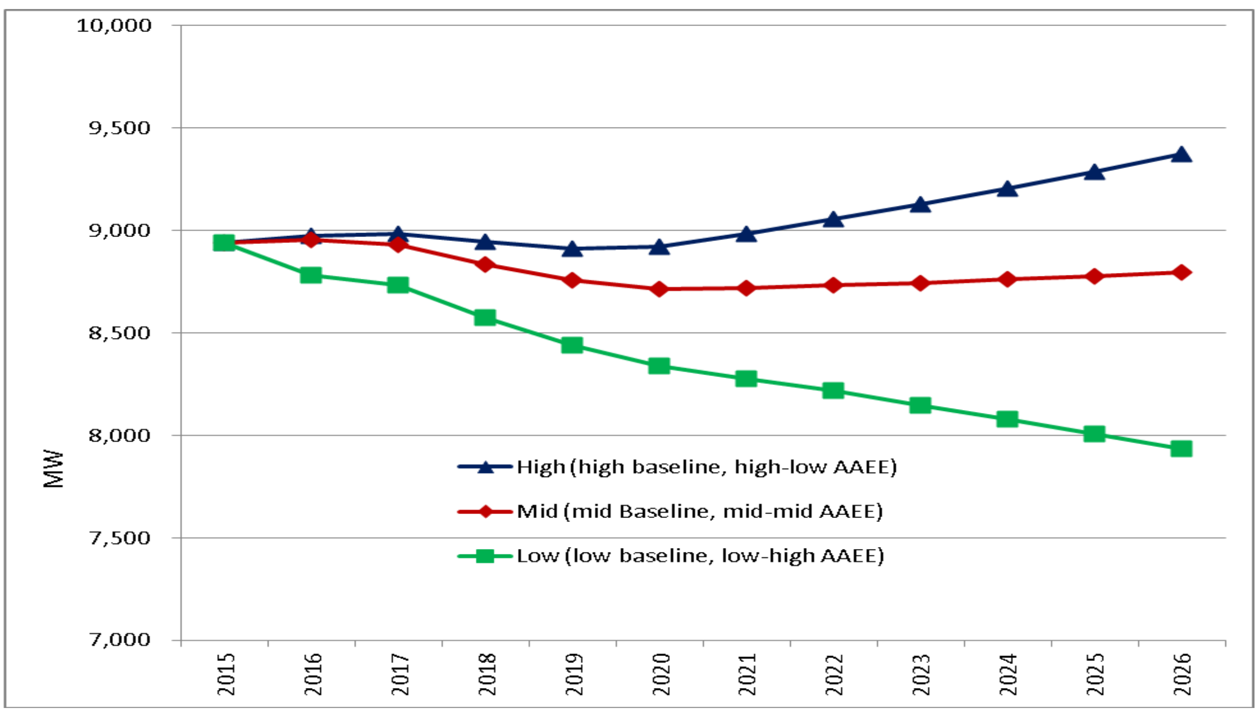
57 http://www.energy.ca.gov/2015_energypolicy/documents/index.html#12172015.

Figure 32: Adjusted Demand Cases for Electricity Sales, Combined POU Service Territories



Source: California Energy Commission, Demand Analysis Office, 2015

Figure 33: Adjusted Demand Cases for Peak, Combined POU Service Territories



Source: California Energy Commission, Demand Analysis Office, 2015

Acronyms and Abbreviations

Acronym/Abbreviation	Original Term
2015 IEPR	*2015 Integrated Energy Policy Report*
2015 Potential Study	*2015 California Energy Efficiency Potential and Goals Study*
2017 IEPR	*2017 Integrated Energy Policy Report*
AAEE	Additional achievable energy efficiency
AC	Alternating current
ARB	California Air Resources Board
BANC	Balancing Authority of Northern California
BUGL	Burbank-Glendale
California ISO	California Independent System Operator
CCA	Community choice aggregator
CED	*California Energy Demand*
CED 2013	*California Energy Demand 2014-2024 Final Forecast*
CED 2015 Preliminary	*California Energy Demand 2016-2026, Preliminary Electricity Forecast*
CED 2015 Revised	*California Energy Demand 2016-2026, Revised Electricity Forecast*
CEDU 2014	*California Energy Demand Updated Forecast, 2015-2025*
CPUC	California Public Utilities Commission
CEUS	Commercial End-Use Survey
CHP	Combined heat and power
CSI	California Solar Initiative
DAWG	Demand Analysis Working Group
DG	Distributed generation
DMV	California Department of Motor Vehicles
DOE	U.S. Department of Energy
DOF	California Department of Finance
DWR	California Department of Water Resources

E3	Energy and Environmental Economics
EIA	U.S. Energy Information Administration
EM&V	Evaluation, measurement, and verification
Energy Commission	California Energy Commission
ERP	Emerging Renewables Program
EV	Electric vehicle
GDP	Gross domestic product
GHG	Greenhouse gas
GSP	Gross state product
GWh	Gigawatt-hour
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	Investor-owned utility
IRR	Internal rate of return
JASC	Joint Agency Steering Committee
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LED	Light-emitting diode
MW	Megawatt
MWh	Megawatt hour
NAICS	North American Classification System
NEM	Net energy metering
NCNC	Northern California Non-California ISO
NREL	National Renewable Energy Laboratory
NSHP	New Solar Homes Partnership
PG&E	Pacific Gas and Electric Company
POU	Publicly owned utility
PV	Photovoltaic

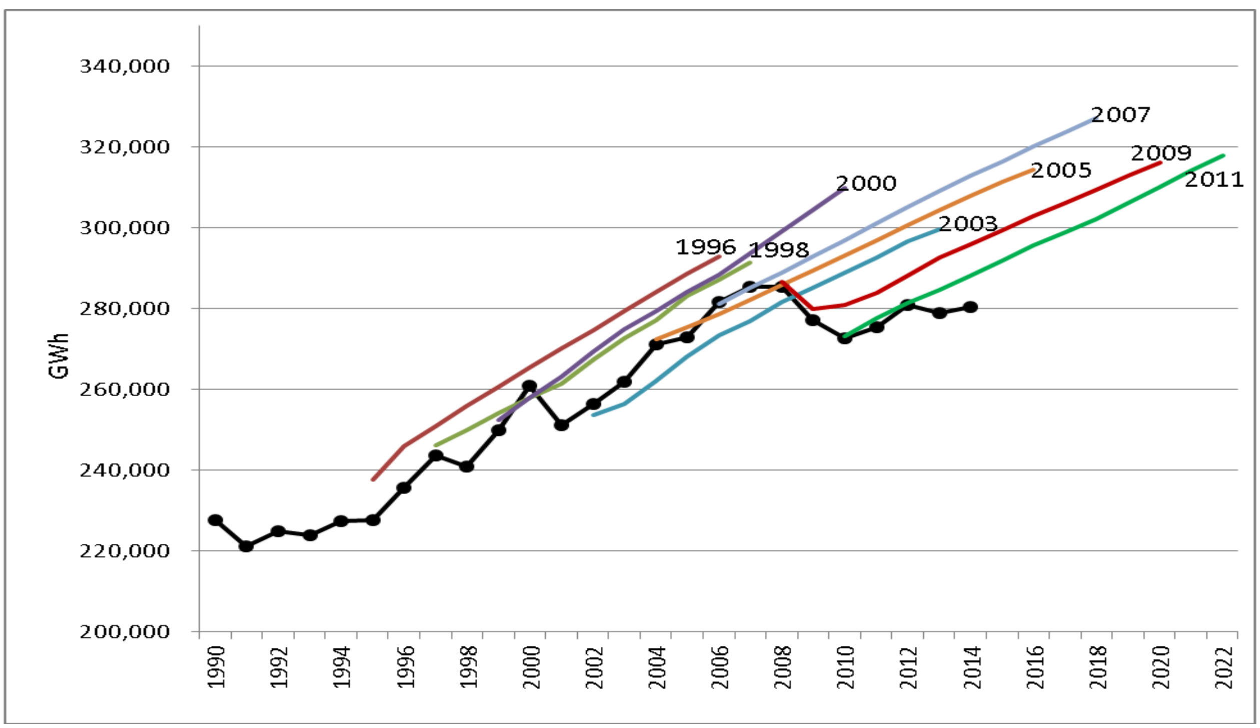
QFER	Quarterly Fuel and Energy Report
RASS	Residential Appliance Saturation Survey
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SHW	Solar hot water
SMUD	Sacramento Municipal Utility District
TAC	Transmission Access Charge
TCU	Transportation, communication, and utilities
TOU	Time-of-use
TRC	Total Resource Cost
UES	Unit energy savings
ZEV	Zero-emission vehicle
ZNEH	Zero-net-energy home

APPENDIX A:
FORECAST PERFORMANCE

This appendix discusses the performance of the demand forecast models used in *CED 2015 Revised* and previous forecasts relative to actual electricity consumption, the metric the models are designed to project. Staff examined consumption forecasts compared to subsequent actual consumption at the statewide level going back to the *1996 Electricity Report*. In addition, model *backcasts*, or predictions of historical outcomes, for *CED 2015 Revised* are compared to historical consumption.

Figure A-1 shows historical electricity consumption statewide from 1990-2014 along with forecasted consumption from staff forecasts from 1996-2011. These forecasts are an aggregation of sector model results at the planning area level. The forecast curves typically begin one year before the forecast vintage because the forecasts are calibrated to the last historical year available. Since historical Quarterly Fuel and Energy Report (QFER) consumption data have been revised at various times over the years to improve accuracy, the forecast starting point does not always coincide with the latest historical consumption estimates. These are baseline forecasts, meaning committed efficiency only. Energy Commission demand forecasts are meant to be long-term predictions and are not necessarily designed to capture all short-term consumption fluctuations.

Figure A-1: Statewide Forecasts vs. Historical Consumption

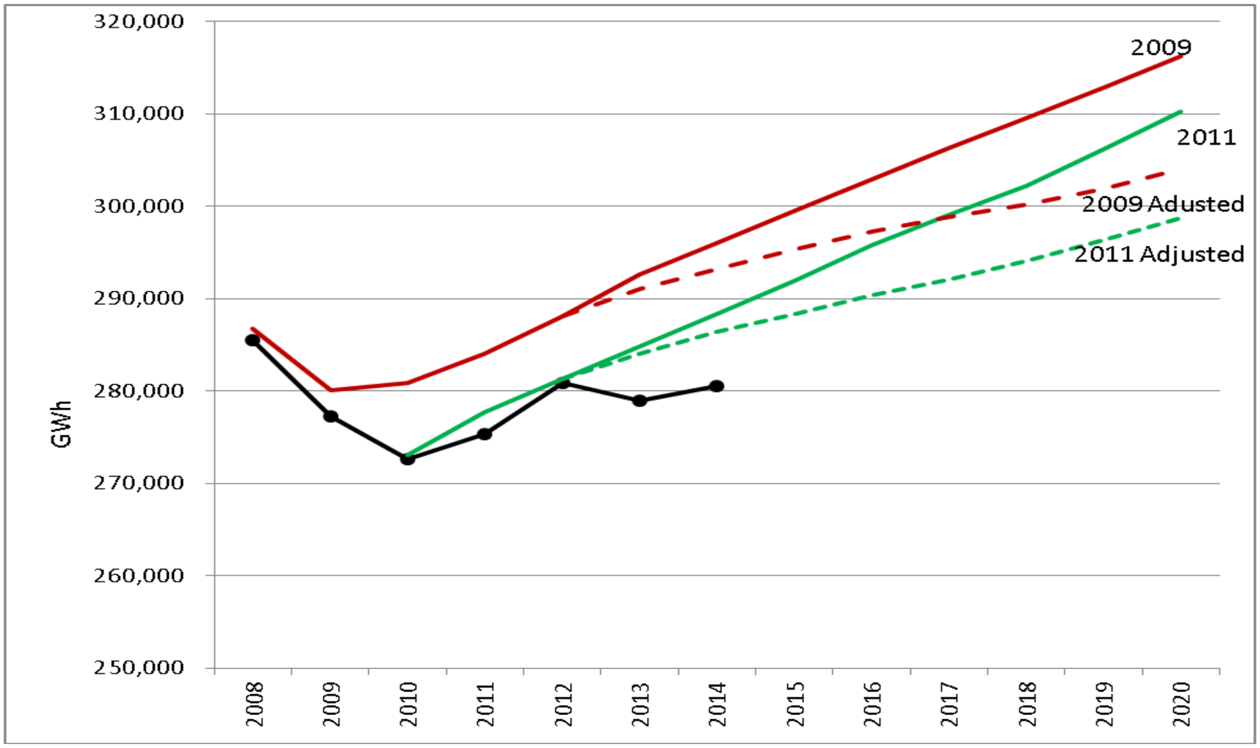


Source: California Energy Commission, Demand Analysis Office, 2015

The *1996 Electricity Report* forecast begins significantly above actual consumption in 1995 because of recent updates in the QFER consumption data. The forecast misses the electricity crisis in 2001, which is not surprising since such an episode is out of the scope of typical consumption models. It also misses the sharp increase in electricity consumption accompanying the "tech boom" of the late 1990s. Overall, however, projected growth from 1995-2006 is close to historical growth, 23.2 percent versus 23.7 percent. The 1998 and 2000 *Energy Outlook* forecasts also miss both the tech boom and the electricity crisis, although projected growth from 2001-2007 in both forecasts is not significantly different from growth in historical consumption (11.4 percent and 11.5 percent for the 1998 and 2000 forecasts, respectively, versus 13.7 percent for historical consumption). The *2003 IEPR* forecast appears to underpredict consumption slightly until 2008. Starting with the 2000 *Energy Outlook* forecast through the *2009 IEPR* forecast, consumption is overpredicted starting in 2008 with the coming of the Great Recession. This is understandable, given that most economic forecasts through 2007 did not predict any significant downturn. The *2009 IEPR* forecast, undertaken after the start of the recession, shows an initial decrease but still overpredicts consumption starting in 2010. The *2011 IEPR* forecast tracks the impact of the economic recovery through 2012 but afterward overpredicts consumption.

Given state policy emphasis on efficiency in the last few years, it is possible that the more recent forecasts as shown overpredict consumption from 2008 onward at least partly because they do not include additional efficiency impacts not yet firm but that were reasonably likely to occur (that is, AAEE savings). The *2009 IEPR* and *2011 IEPR* forecasts include adjustments for AAEE savings expected from the IOUs. **Figure A-2** shows these baseline forecasts when adjusted for the mid scenario for AAEE from 2009 and 2011. These adjustments bring the forecasts marginally closer to actual consumption in 2013 and 2014, but there remains a sizable gap between predicted and actual.

Figure A-2: Adjusted Statewide Forecasts vs. Historical Consumption



Source: California Energy Commission, Demand Analysis Office, 2015

Ideally, model performance over some historical period should be judged by rerunning the models using actual inputs for economic and demographic growth, as well as rates and weather variables instead of what was predicted at the time of the forecast. Fortunately, the residential and commercial models provide a backcast to 1975, which gives estimated model results using the actual historical inputs such as personal income, population, and so on. Models for the other sectors do not provide full backcasts but rather index base year results to actual consumption in that year. However, the residential and commercial sectors are by far the largest,[58] and historical data for residential plus commercial consumption can be compared to model backcasts.

Raw output from the residential and commercial models is weather-adjusted—modified to account for differences between weather averaged over a period of years and actual historical weather— by scaling results based on the number of actual heating and cooling degree days in a given year relative to long-term averages. In addition, impacts from efficiency programs not incorporated directly in the models are subtracted from weather-adjusted results. After the efficiency adjustment, results are calibrated to actual 2014 consumption for *CED 2015 Revised*. **Figure A-3** shows the statewide weather- and efficiency-adjusted residential and commercial

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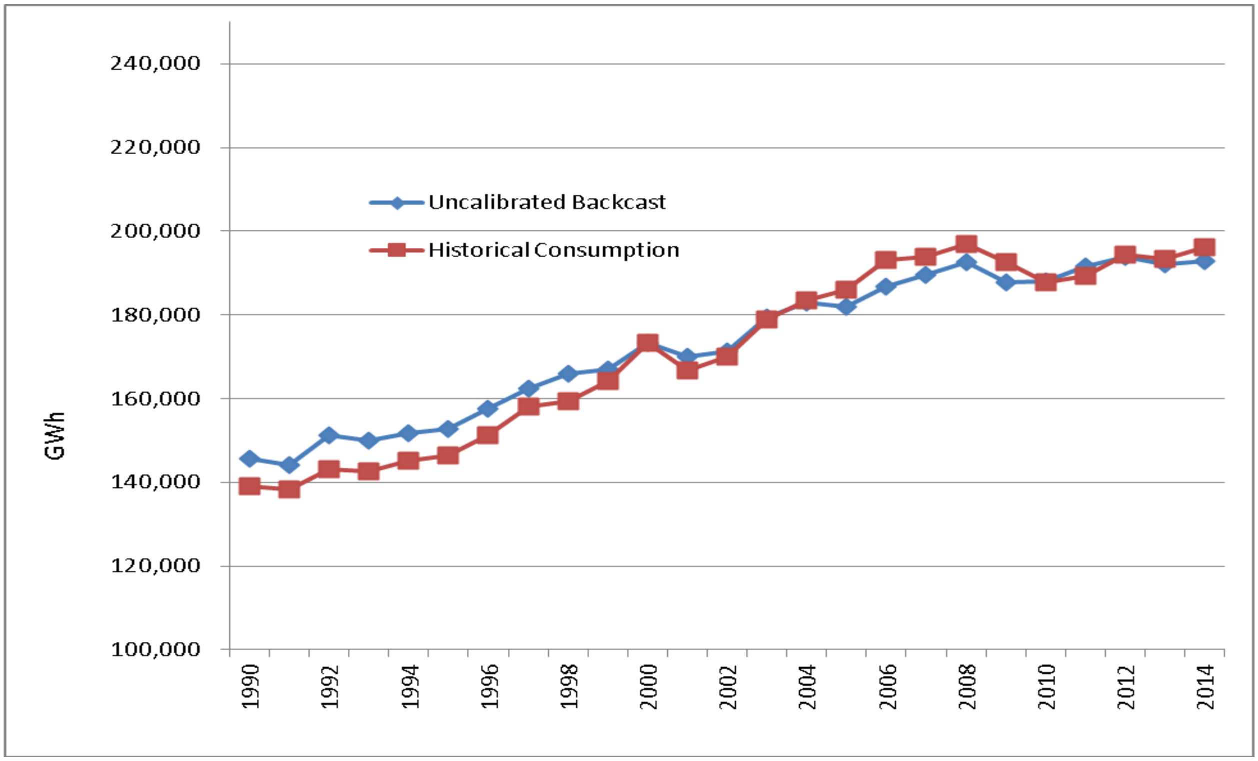
58 Around 70 percent of total electricity consumption in 2014.

model output from *CED 2015 Revised* before calibration compared with historical residential and commercial consumption at the statewide level for 1990-2014.

Figure A-3: Residential Plus Commercial Model Backcast vs. Historical Consumption



Source: California Energy Commission, Demand Analysis Office, 2015

Using best estimates of actual historical inputs, predicted output matches much more closely with historical consumption.[59] The backcast tracks approximately the impacts of the Great Recession and subsequent recovery, as well as the tech boom and economic upturn starting in 2003. The electricity crisis is partially captured through rate increases in 2001. However, the results do indicate that the models might not be as sensitive to economic changes as they should be, since the changes in consumption for 1998-2000, 2004-2008, and 2008-2010 are slightly understated in the backcast. Predicted consumption in the 1990s is too high, although backcast growth roughly matches actual growth during this period. Despite these issues, the models together do not appear to exhibit any obvious bias upward or downward over this period. Staff plans to enhance these models with a statistically adjusted end use component,[60] tying uncalibrated model output more closely to consumption.

59 More recent economic and demographic historical data (after 2010) are subject to later revision.

60 End-use statistical adjustments involve an econometric component that is designed to modify consumption estimates at the end-use level so that overall model output matches more actual consumption more closely.

APPENDIX B: SELF-GENERATION FORECASTS

Compiling Historical Distributed Generation Data

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

- The California Solar Initiative (CSI).[61]
- New Solar Homes Partnership (NSHP).[62]
- Self-Generation Incentive Program (SGIP).[63]
- CSI Thermal Program for Solar Hot Water (SHW).[64]
- Emerging Renewables Program (ERP).[65]
- POU programs.[66]
- Utility interconnection filing.[67]

In addition, power plants with a generating capacity of at least 1 MW are required to submit fuel use and generation data to the Energy Commission under the QFER Form 1304.[68] QFER data include fuel use, generation, onsite use, and exports to the grid. These various sources of data were used to quantify DG activity in California and to build a comprehensive database to track DG activity. One concern in using incentive program data along with QFER data is the possibility of double-counting generation if the project has a capacity of at least 1 MW. This may occur as the publicly available incentive program data do not list the name of the entity receiving the DG incentive for confidentially reasons, while QFER data collect information from the plant owner. Therefore, it is not possible to determine if a project from a DG incentive

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61 Downloaded on June 25, 2014 from (http://www.californiasolarstatistics.org/current_data_files/).

62 Program data received on March 11, 2015, from staff in the Energy Commission's Renewables Office.

63 Downloaded on August 3, 2015, from (https://energycenter.org/index.php/incentive-programs/self-generation-incentive-program/sgip-documents/sgip-documents).

64 Downloaded on August 18, 2015, from (http://www.gosolarcalifornia.org/solarwater/index.php)

65 Program data received on January 18, 2013, from staff in the Energy Commission's Renewables Office.

66 Program data submitted by POU's on July 2015 (http://www.energy.ca.gov/sb1/pou_reports/index.html).

67 *2015 Integrated Energy Policy Report* data request available at (https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03).

68 Data received from Energy Commission's Supply Analysis Office on September 9, 2015.

program is already reporting data to the Energy Commission under QFER. For example, the SGIP has 156 completed projects that are at least 1 MW and about 70 pending projects that are 1 MW or larger. Given the small number of DG projects meeting the reporting size threshold of the QFER, double-counting may not be significant but could become an issue as an increasing amount of large SGIP projects come on-line.

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

Projects from incentive programs were classified as either completed or uncompleted. This was accomplished by examining the current status of a project. Each program varies in how it categorizes a project. CSI projects having the following statuses are counted as completed projects: “Completed,” “PBI – In Payment,” “Pending Payment,” “Incentive Claim Request Review,” and “Suspended – Incentive Claim Request Review.” For the SGIP program, a project with the status “Payment Completed” or “Payment PBI in Process” is counted as completed. For the ERP program, there was no field indicating the status of a project. However, there was a column labeled “Date_Completed,” and this column was used to determine if a project was complete or incomplete. For the NSHP, a project that has been approved for payment is counted as a completed project. For SHW, any project having the status “Paid” or “In Payment” was counted as a completed project.

POU PV data provided installations by sector. Staff then projected when incomplete projects will be completed based on how long it has taken completed projects to move between the various application stages. The next step was to assign each project to a county and sector. For most projects, the mapping to a county is straightforward since either the county information is already provided in the data or a zip code is included. For nonresidential projects, when valid North American Classification System (NAICS) codes are provided in the program data, the corresponding NAICS sector description was used; otherwise, a default “Commercial” sector label was assigned. Each project was then mapped to one of 16 demand forecasting climate zones[69] based on utility and county information. These steps were used to process data from all incentive programs in varying degrees to account for program-specific information. For example, certain projects in the SGIP program have an IOU as the program administrator but are interconnected to a POU; these projects were mapped directly to forecasting zones. For the ERP program, PV projects less than 10 kW were mapped to the residential sector, while both non-PV and PV projects greater than 10 kW were mapped to the commercial sector. Finally,

69 The PV predictive model has not yet been transitioned to the new scheme with 20 forecast zones.

capacity and peak factors from DG evaluation reports and PV performance data supplied by the CPUC were used to estimate energy and peak impacts.[70 71]

Staff then needed to make assumptions about technology degradation. PV output is assumed to degrade by .5 percent annually; this rate is consistent with other reports examining this issue.[72] Staff decided to not degrade output for non-PV technologies, given the uncertainty in selecting an appropriate factor and the implication of using these factors in a forecast with a 10-year horizon. This decision was based on information from a report focused on combined heat and power projects funded under the SGIP program.[73] The report found significant decline in energy production annually by technology; however, the reasons for the decline varied and ranged from improper planning during the project design phase, a lack of significant coincident thermal load (for combined heat and power applications), improper maintenance, and fuel price volatility. Also, some technologies, such as fuel cells and microturbines, were just beginning to be sold in the market, and project developers did not have a full awareness of how these technologies would perform in a real-world setting across different industries. This does not mean that staff will not use degradation factors in future reports. Once better data have been collected, staff will revisit this issue. Another issue with projects funded under SGIP is the need to account for decommissioned projects. Currently, the publicly available SGIP data set does not identify if a previously funded project has been decommissioned.

For the *2015 IEPR* demand forecast, staff requested monthly PV interconnection data by zip code and sector from utilities under data collection regulations under IEPR for installations occurring between 2012 through 2014. This was primarily initiated due to informal comments staff received from utility forecasters suggesting that a number of PV projects were being installed and where customer-generators were not seeking a rebate from an incentive program. Since staff's historical record of PV installation is based on participation through rebate programs, this issue could significantly understate staff's understanding of trends in PV adoption, particularly given the steep cost reduction of a PV system in recent years. **Table B-1** shows the discrepancy between staff's estimate of annual PV additions and the interconnection data submitted by the IOUs for the *2015 IEPR.*

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

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

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

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

Table B-1: PV Interconnection 2012-2013

Annual PV Additions (MW)			
Utility	Year	Utility *2015 IEPR* Filing	CEC
PG&E	2012	180	184
PG&E	2013	260	163
SCE	2012	136	163
SCE	2013	184	161
SDG&E	2012	37	31
SDG&E	2013	67	33

Source: California Energy Commission, Demand Analysis Office, 2015

As **Table B-1** makes clear, the difference in PV installation between staff's compilation of publicly available data and utility interconnection data is significant. Around the fall of 2014, staff recommended that the Energy Commission make changes to its data collection regulations to better capture PV installations in the state. This effort may be consolidated into a broader reform of data collection regulations currently under proposal at the Energy Commission. To avoid double-counting, a PV project from a rebate program was retained only if the project was installed before 2012. After 2012, staff relied solely on interconnection data to track PV. Most small public utilities are not subject to the IEPR data collection requirement; so staff continued to rely on the POU Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) data collected by the Energy Commission.

Figure B-1 shows statewide energy use from PV and non-PV technologies. Historically, PV constituted a small share of total self-generation; however, PV use begins to show a sharp increase as the CSI program started to gain momentum after 2007 and by 2014 accounted for more than 25 percent of total self-generation. For self-generation as a whole, the residential sector has seen tremendous growth in recent years, driven largely by PV. In 2014, self-generation from the residential sector was estimated to be more than 13 percent of the statewide total in 2014.

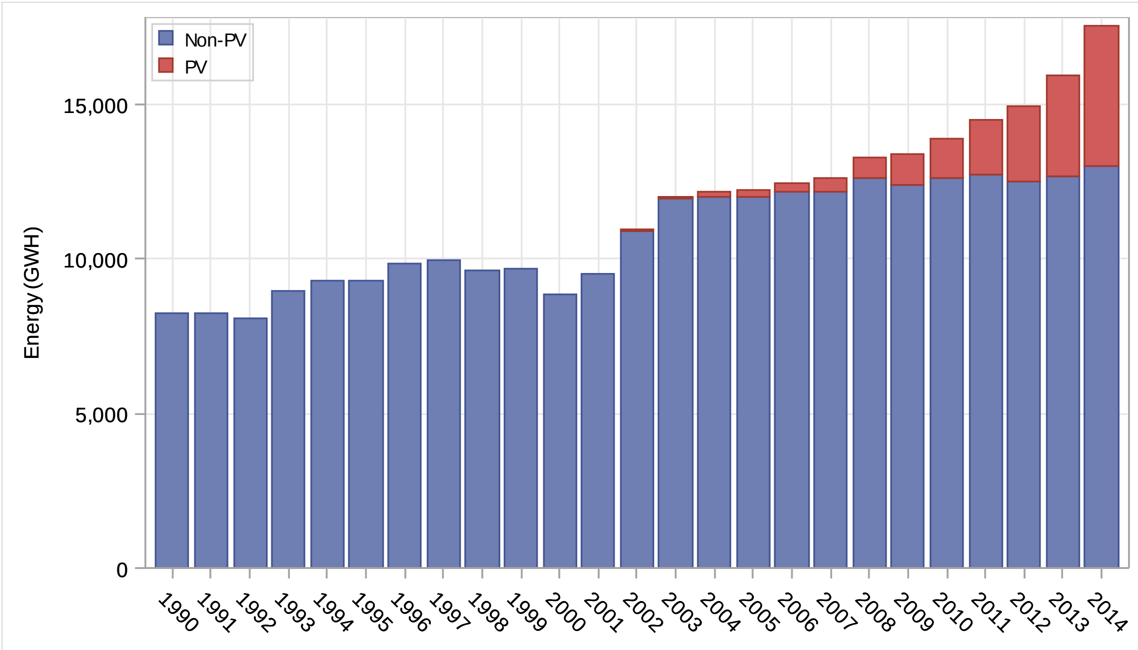
Figure B-2 shows PV self-generation by sector from 1995 to 2014. PV adoption is generally concentrated in the residential and commercial sectors. The growth in PV adoption was initially driven by the CSI program and shows no sign of slowing down even though CSI rebates have largely expired.

Figure B-3 shows the top 20 counties with PV by sector in 2014. PV capacity is led by Southern California with Los Angeles, San Diego, and Riverside Counties making up the top three counties in the state with PV installations.

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

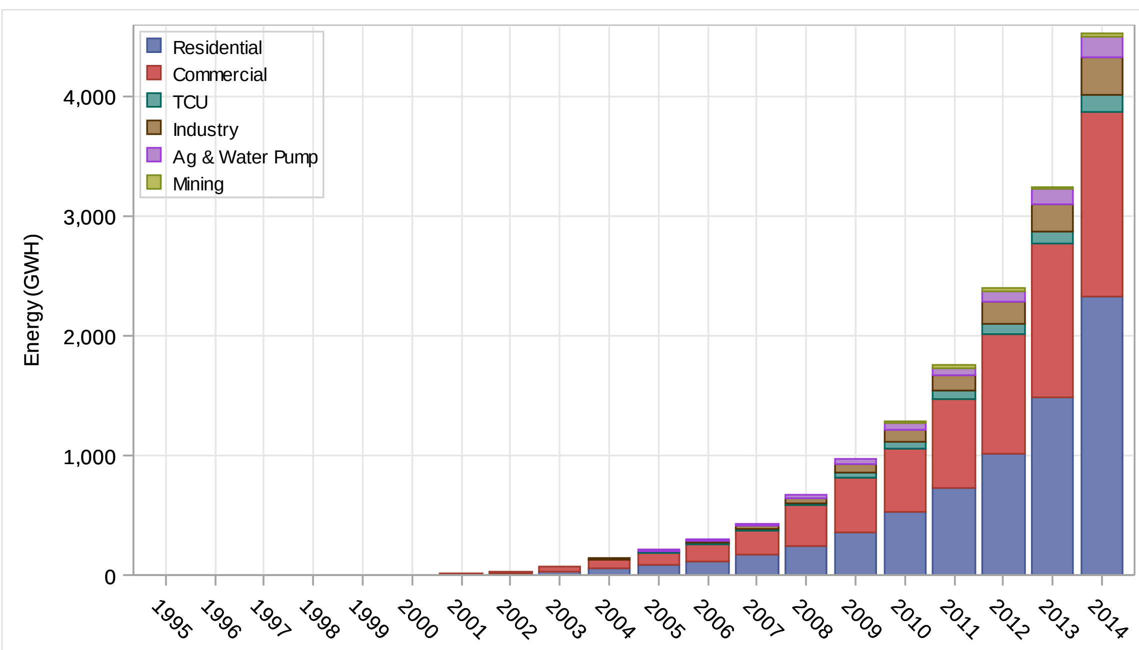
Figure B-5 gives a breakout of self-generation by technology and shows the rapid increase from PV generation.

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



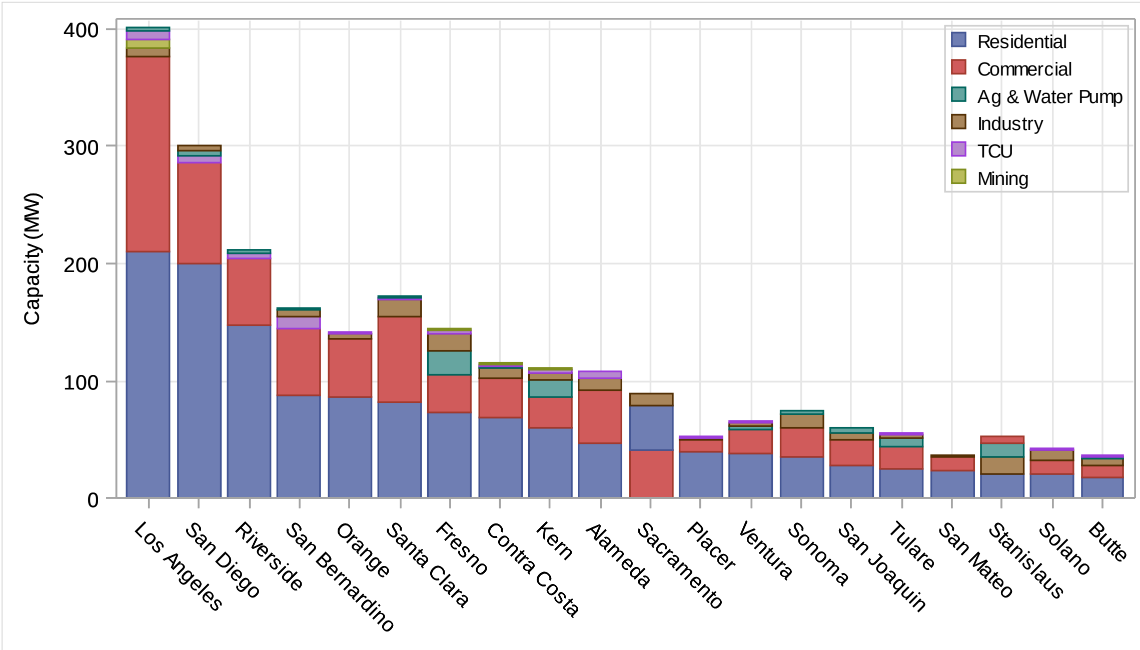
Source: California Energy Commission, Demand Analysis Office, 2015

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



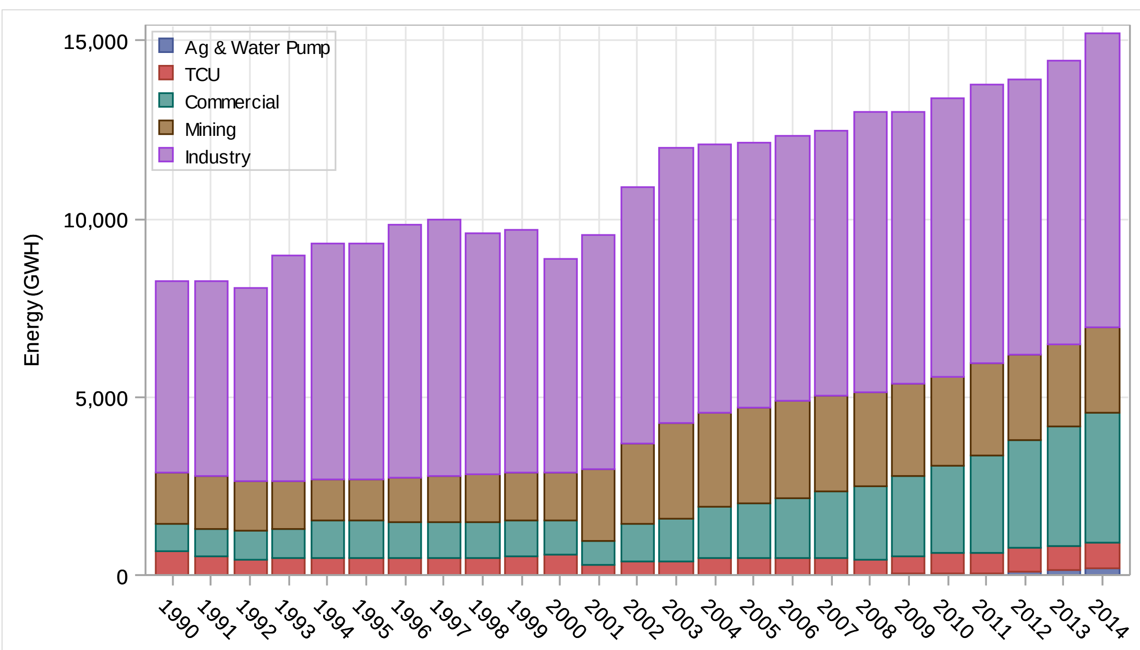
Source: California Energy Commission, Demand Analysis Office, 2015

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



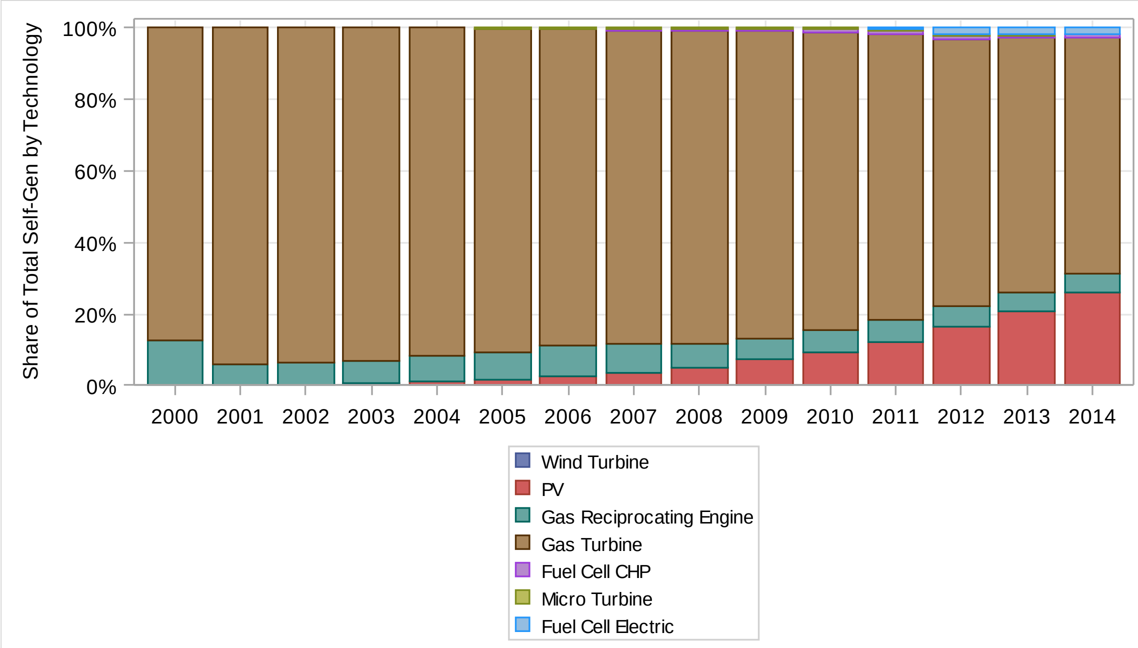
Source: California Energy Commission, Demand Analysis Office, 2015

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



Source: California Energy Commission, Demand Analysis Office, 2015

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



Source: California Energy Commission, Demand Analysis Office, 2015

Residential Sector Predictive Model

The residential sector self-generation model was designed to forecast PV and SHW adoption using estimated times for full payback, which depends on fuel price, system cost, and performance assumptions. The model is similar in structure to the cash flow-based DG model in the National Energy Modeling System as used by the U.S. Energy Information Administration (EIA)[74] and the *SolarDS* model developed by the National Renewable Energy Laboratory (NREL).[75]

Changes to the residential sector model were made based on the need to account for the effect of net metering and the design of residential retail rates. Staff collected data on historical retail rates for the investor-owned utilities. Due to time constraints, staff will continue to use average sector rates as developed for *CED 2015 Revised* forecast for publicly owned utilities.[76] Due to

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

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

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

limited participation from the multifamily segment of the residential sector, staff limited its modeling of PV adoption to single-family homes.[77]

PV cost and performance data were based on analysis performed by Energy and Environmental Economics (E3) for the CPUC.[78] [79] Historical PV price data were compiled from rebate program data and a comprehensive report from Lawrence Berkeley National Laboratory.[80] To forecast the installed cost of PV, staff adjusted the base year mean PV installed cost to be consistent with the PV price forecast developed by E3 for the mid demand case with about a 2 percent variation relative to the mid demand case for the high and low demand cases.

SHW cost and performance data were based on analysis conducted by ITRON in support of a CPUC proceeding examining the costs and benefits of SHW systems.[81] Adjustments were made for incentives offered by the appropriate utility to obtain the net cost.

Residential electricity and gas rates consistent with those used in *CED 2015 Revised* were used to calculate the value of bill savings. Historical and current retail rates were used for IOUs up until 2015. After 2015, staff used the rate structure proposed in a CPUC decision on residential rate redesign.[82] This decision brings substantial changes to the existing design of residential rates. It will collapse the current four tiers into two tiers, with a special tier for high energy users. It will also impose a minimum monthly bill. One goal of this decision is to eventually move to a time-of-use (TOU) rate structure and where the decision calls for TOU pilot programs to begin in 2020. Further, the passage of Assembly Bill 327 (Perea, Chapter 611, Statutes of 2013) may bring about significant changes to net energy metering (NEM), a mechanism designed to compensate customer-generators for excess generation.[83] Currently, excess generation is valued at the full retail rate. The CPUC has not yet issued a final decision regarding details of a successor NEM tariff. Parties to this proceeding have made recommendations on the future design of a successor tariff that varies from no change at all to complex time differentiated compensation for customer export and a fixed customer charge that may depend on the

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

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

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

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

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

82 Decision available at (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF).

83 http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm.

capacity of the NEM eligible technology. Since this proceeding is ongoing, staff assumed that excess generation will continue to be valued at the full retain rate in the low demand case. The high demand case models a hypothetical NEM successor tariff having a $3/kW capacity charge, a fixed $0.10/kWh compensation for any export by a customer-generator, and monthly netting.[84] The low demand case represents continuation of the existing NEM compensation scheme, while the high demand case captures the intent of utilities to reform NEM to address a perceived shift in cost from occurring by customers with PV to customers without PV. The mid demand case is a blend of the two bookend cases. Bill savings, including NEM calculation, also incorporate data on annual electric consumption from the Energy Commission's *2009 Residential Appliance Saturation Survey*[85] (RASS) and residential load shape data submitted by utilities as part of the *2015 IEPR* data request. The useful life for both PV and SHW was assumed to be 30 years, which is longer than the forecast period. PV surplus generation was valued at a uniform rate of $0.04/kWh in the low demand case.[86]

Projected housing counts developed for *CED 2015 Revised* were allocated to two space-heating types – electric and gas. The allocation is based on saturation levels from RASS. PV systems were sized based on RASS floor space data, assumptions regarding roof slope, and factors to account for shading and orientation.[87] PV system size was constrained to be no more than 4 kW CEC AC for single-family homes (retrofit) and 2 kW CEC AC for new construction. For PV systems, hourly generation over the life of the system was estimated based on data provided to staff by CPUC. For SHW systems, energy saved on an annual basis was used directly to estimate bill savings. PV and SHW energy output were degraded at the same rate based on the PV degradation factor estimated by ICF International for the EIA.[88]

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

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

85 For more information, see: http://www.energy.ca.gov/appliances/rass/ .

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

87 Navigant Consulting Inc. September 2007. *California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential By County*. Report available at (http://www.energy.ca.gov/2007publications/CEC-500-2007-048/CEC-500-2007-048.PDF).

88 ICF International. June 2010. *Photovoltaic (PV) Cost and Performance Characteristics for Residential and Commercial Applications*. Report prepared for the U.S. Energy Information Administrator and available as Appendix A at (http://www.eia.gov/analysis/studies/distribgen/system/pdf/full.pdf).

The payback calculation was based on the IRR method used in the *SolarDS* model. The IRR approach takes an investment perspective and takes into account the full cash flow resulting from investing in the project. The cash flow is first converted to an annuity stream before the IRR is calculated. This is necessary since outlays to handle inverter replacement may cause issues in solving for the IRR.[89] In general, the higher the IRR of an investment, the more desirable it is to undertake. Staff compared the IRR to a required hurdle rate (5 percent) to determine if the technology should be adopted. If the calculated IRR was greater than the hurdle rate, then payback was calculated; otherwise, the payback was set to 25 years. The formula for converting the calculated IRR (if above 5 percent) to payback is:

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

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

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

Payback sensitivity was set to 0.3.[90] To estimate actual penetration, maximum market share was multiplied by an estimated adoption rate, calculated using a Bass Diffusion curve, to estimate annual PV and SHW adoption. The Bass Diffusion curve is often used to model adoption of new technologies and is part of a family of technology diffusion functions characterized as having an "S" shaped curve to reflect the different stages of the adoption process.

The adoption rate is given by the following equation:

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

The terms *p* and *q* represent the effect of early and late adopters of the technology, respectively. Staff used mean values for *p* (0.03) and *q* (0.38), derived from a survey of empirical studies.[91]

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

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

91 Meade, Nigel and Towidul Islam. 2006. "Modeling and Forecasting the Diffusion of Innovation – A 25-Year Review," *International Journal of Forecasting*, Vol. 22, Issue 3.

Self-Generation Forecast, Nonresidential Sectors

Commercial Combined Heat and Power and Photovoltaic Forecast

CED 2015 Revised continues to use the predictive model developed for the *2013 IEPR* demand forecast to model adoption of CHP and PV in the commercial sector. This model uses the same basic payback framework as in the residential predictive model. Staff began by allocating energy use to different building types using the *2006 Commercial End-Use Survey* (CEUS).[92] The survey contains information on each site that participated in the survey, including:

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

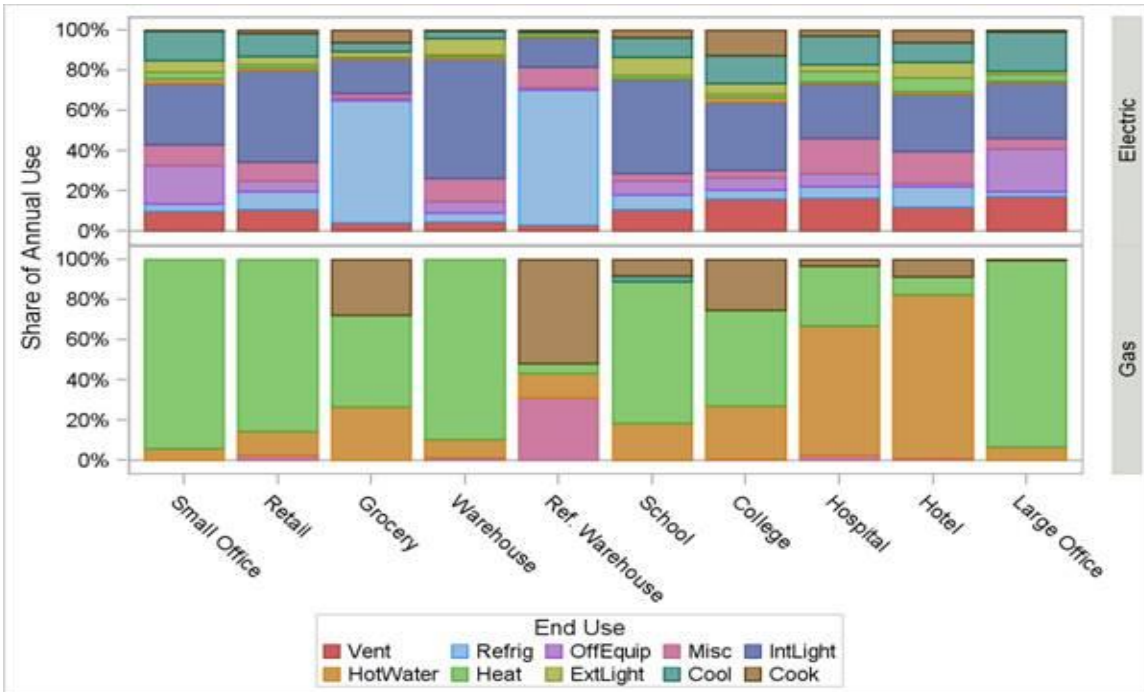
Building sizes were grouped into four size categories based on annual electricity use. Fuel intensities (use per square foot) were then calculated for each building type and size for electricity and natural gas.

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

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

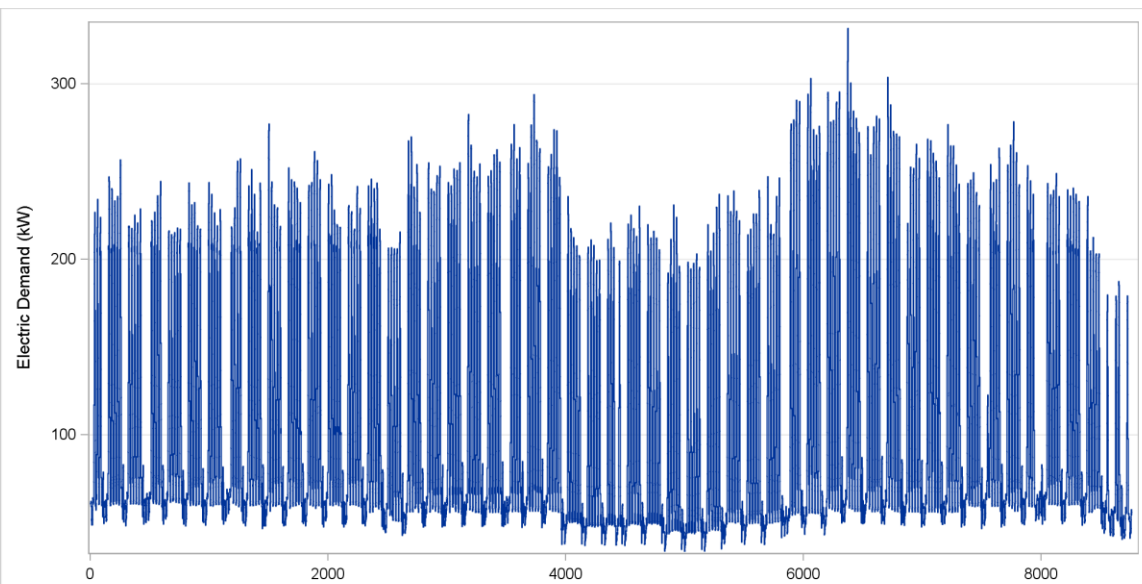
92 Itron. March 2006. Report available at http://www.energy.ca.gov/2006publications/CEC-400-2006-005/CEC-400-2006-005.PDF.

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



Source: California Energy Commission, Demand Analysis Office, 2015

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



*In chronological order (8,760 annual hours).

Source: California Energy Commission, Demand Analysis Office, 2015

Next, the commercial sector model output was benchmarked to the 2014 QFER electricity and gas sales data. The distribution of energy use by fuel type and end use was then applied to the CEUS site-level data and expanded by the share of floor space stock represented by the site. This essentially "grows" the site level profile from the CEUS survey to match the QFER calibrated commercial model output by end use, fuel type, forecast zone, demand case, and year.

For CHP, staff assumed that waste heat will be recovered to meet the site demand for hot water and space heating and that this will displace gas used for these two purposes.[93] Based on this assumption, the power-to-heat ratio was then calculated for each building type and size category by forecast climate zone and demand case.

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

Finally, cost and benefits were developed to derive payback. Staff applied the same set of assumptions used in a prior Energy Commission-sponsored report to characterize CHP technology operating characteristics such as heat rate, useful heat recovery, installed capital cost, and operating costs.[94] PV technology details such as installed cost and operating cost were based from the same E3 dataset used for the residential sector predictive model. Avoided retail electric and gas rates were derived from utility tariff sheets and based on estimated premise-level maximum demand. Current retail electric and gas rates were escalated based on the rates of growth for fuel prices developed for the *CED 2015 Revised*. In addition, CHP technologies may face additional costs such as standby and departing load charges. Details for these charges were also collected and used in the economic assessment. Staff examined details surrounding the applicability of these charges and applied them as appropriate. The fuel cost for using gas by the different CHP technologies also had to be estimated. Staff began with border prices and then added a transportation charge. Staff from the Energy Commission's Supply Analysis Office (SAO) supplied the historical border prices. The Malin border price was used for PG&E, and the Topock-Needles border price was used for both SoCal Gas and SDG&E. For the forecast period, staff escalated average 2014 border prices at a rate consistent with SAO's gas rate scenarios. Staff also identified federal tax credits for installing CHP and PV and assessed the eligibility for utility rebate programs such as the SGIP and CSI.

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

94 Ibid.

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

Other Sector Self-Generation

Staff used a trend analysis for forecasting adoption of PV in the noncommercial/nonresidential sectors. For SHW, staff assumed that nonresidential sector adoption would follow a ratio similar to residential versus nonresidential PV adoption. New for *CED 2015 Revised* is an initial focus on energy storage systems. Data on energy storage projects from the SGIP rebate program were used to forecast future adoption of energy storage. A majority of energy storage projects are pending through the SGIP application queue and are expected to be operational by 2016 subject to funding availability. While it is envisioned that storage projects would be paired with other technologies, namely PV, the existing fleet of storage projects from SGIP are stand-alone projects. Data from SGIP show that about 84 percent of nonresidential and 93 percent of residential projects are stand-alone projects. The typical case for a nonresidential customer installing energy storage is demand charge reduction, while the case is more nuanced for residential customers.[95]

Photovoltaic Peak Impact

For *CED 2015 Revised*, staff spent some time refining the peak factors used to translate PV installed capacity to impact during utility annual peak hour. Table B-2 shows factors used in prior *IEPR* demand forecast and those proposed for *CED 2015 Revised*.

Table B-2: PV Peak Factors

Utility	CED 2011	CED 2013	CED 2015
PG&E	55%	50%	37%
SCE	62%	50%	40%
SDG&E	68%	50%	40%

Source: California Energy Commission Staff

Factors used in support of *CED 2011* came from a CPUC-sponsored study of impacts of its CSI program.[96] Utility staff commented that the factors were too high, especially in the case of SDG&E. To address these concerns, staff used a uniform factor of 50 percent for *CED 2013*. To refine PV peak factors further in support of *CED 2015,* staff examined simulated PV production profiles provided by CPUC relative to utility annual peak day between 2011 through 2014.

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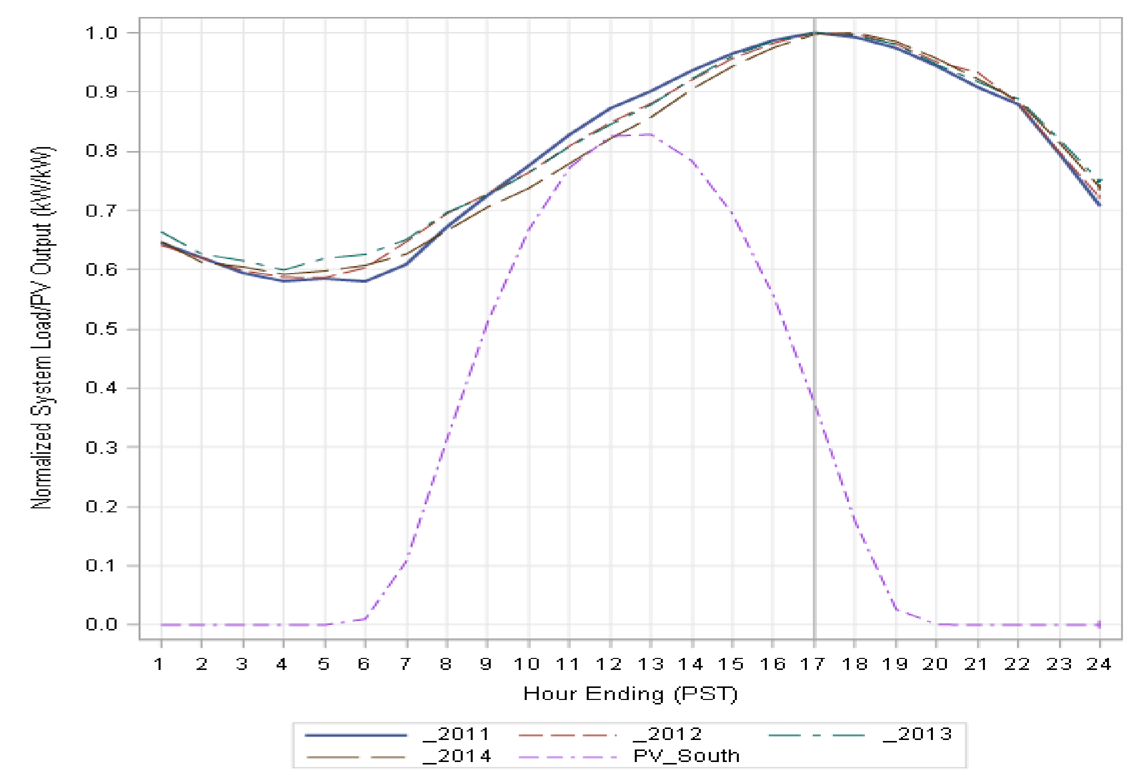
95 Energy Commission staff requested tariff data for customers installing energy storage systems to the IOUs in February 2015. Only SDG&E responded, and SDG&E data showed that none of the residential customers installing energy storage were on a tariff with time-differentiated energy charges.

96 Itron. June 2011. *CPUC California Solar Initiative 2010 Impact Evaluation.* Report available at http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf.

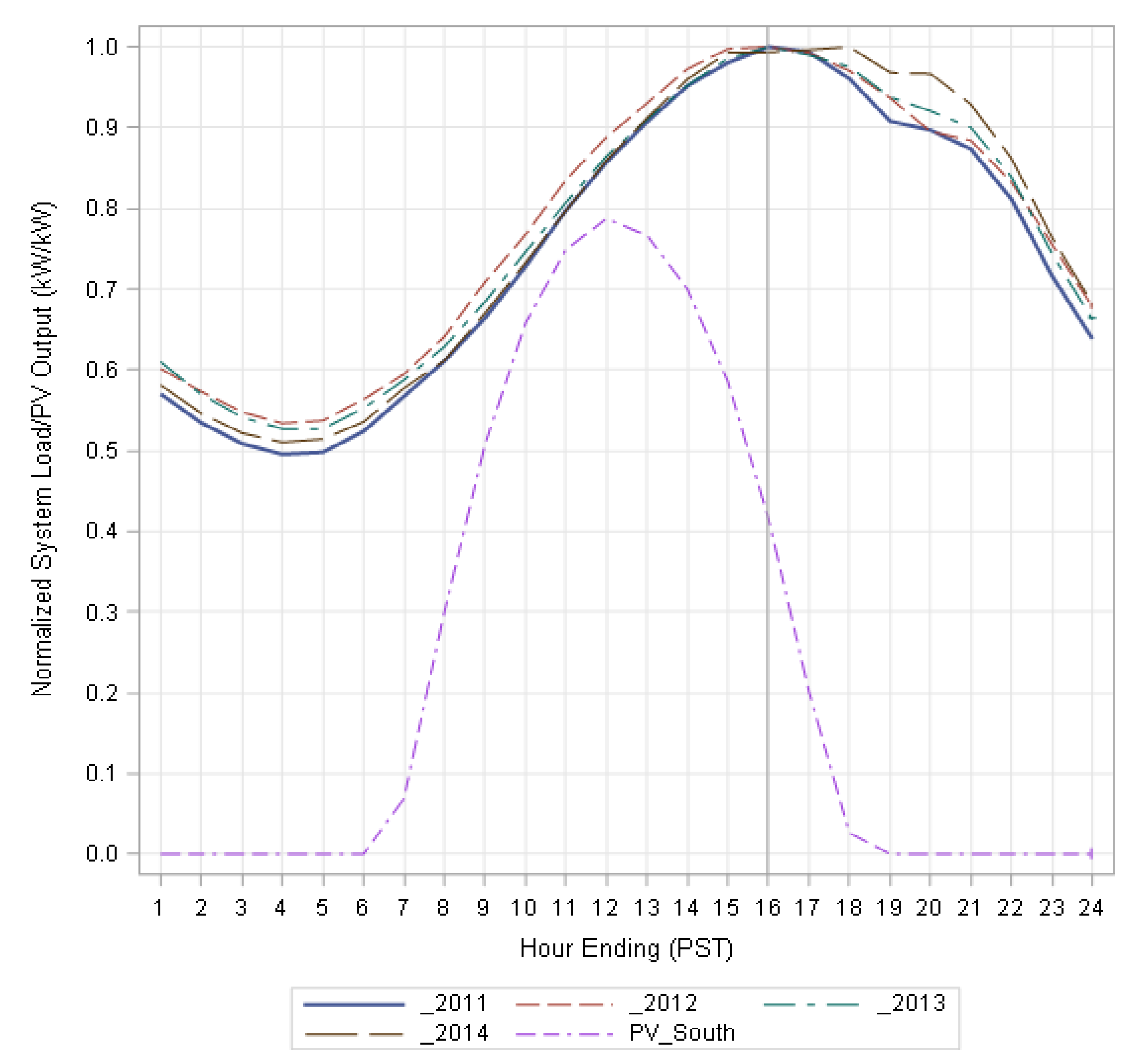
Figure B-8: PG&E System Load vs PV Production



Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-8 shows the hourly load for PG&E annual peak day for 2011 through 2014. The load for each hour was normalized by the annual peak so that the hour corresponding to a value of 1 shows the time of system peak for the given year. The peak occurred on June 21 for 2011, August 13 for 2012, and July 3 and 25 for 2013 and 2014, respectively. The peak hour was 5:00 p.m. for all years, except for 2014 where the peak occurred on 6:00 p.m. Based on additional historical data, staff characterized PG&E as typically having an annual peak in July at 5:00 p.m. The curve labeled "PV_South" shows the normalized PV output in July (averaged over all days) for a representative south-facing PV system in PG&E Forecasting Zone 2 (Sacramento). A vertical reference line corresponding to 5:00 p.m. is drawn to show the coincidence of PV output relative to the expected time of the system peak for PG&E. A similar analysis was done for the other four zones that make up the PG&E planning area, and based on the result, staff lowered the PG&E PV peak factor from 50 percent to 37 percent. Staff performed similar analyses for SCE and SDG&E, which are shown in **Figures B-9 and B-10**.

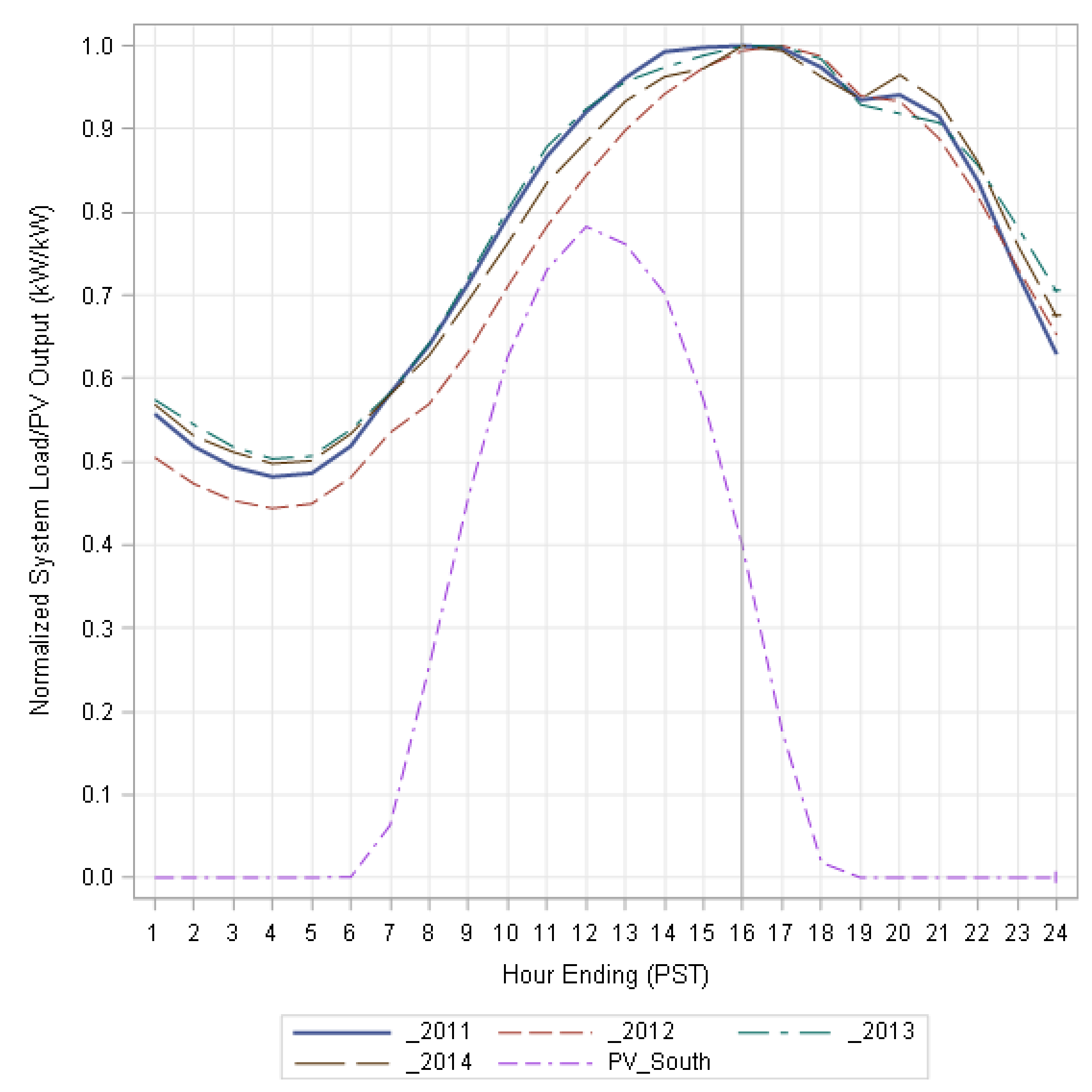
Figure B-9: SCE System Load vs PV Production



Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-9 shows the hourly load for SCE annual peak day for 2011 through 2014. SCE's annual peak occurred on September 7 for 2011, August 13 for 2012, and September 5 and 15 for 2013 and 2014, respectively. Based on additional historical data, staff characterized SCE as typically having an annual peak in September at 4:00 p.m. The curve labeled "PV_South" shows the normalized PV output in September (averaged over all days) for a representative south-facing PV system in SCE Forecasting Zone 7 (Fresno). A vertical reference line corresponding to 4:00 p.m. is drawn to show the coincidence of PV output relative to the expected time of the system peak for SCE. Similar analyses were done for the other three zones that make up the SCE planning area, and based on the result, staff lowered the SCE PV peak factor from 50 percent to 40 percent.

Figure B-10: SDG&E System Load vs PV Production



Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-10 shows the hourly load for SDG&E annual peak day for 2011 through 2014. SDG&E's peak occurred on September 7 for 2011, September 14 for 2012, August 30 for 2013, and September 16 for 2014. Based on additional historical data, staff characterized SDG&E as typically having an annual peak in September at 4:00 p.m. The curve labeled "PV_South" shows the normalized PV output in September (averaged over all days) for a representative south-facing PV system in SDG&E Forecasting Zone 13 (San Diego). A vertical reference line corresponding to 4:00 p.m. is drawn to show the coincidence of PV output relative to the expected time of the system peak for SDG&E. Based on this result, staff lowered the SDG&E PV peak factor from 50 percent to 40 percent.

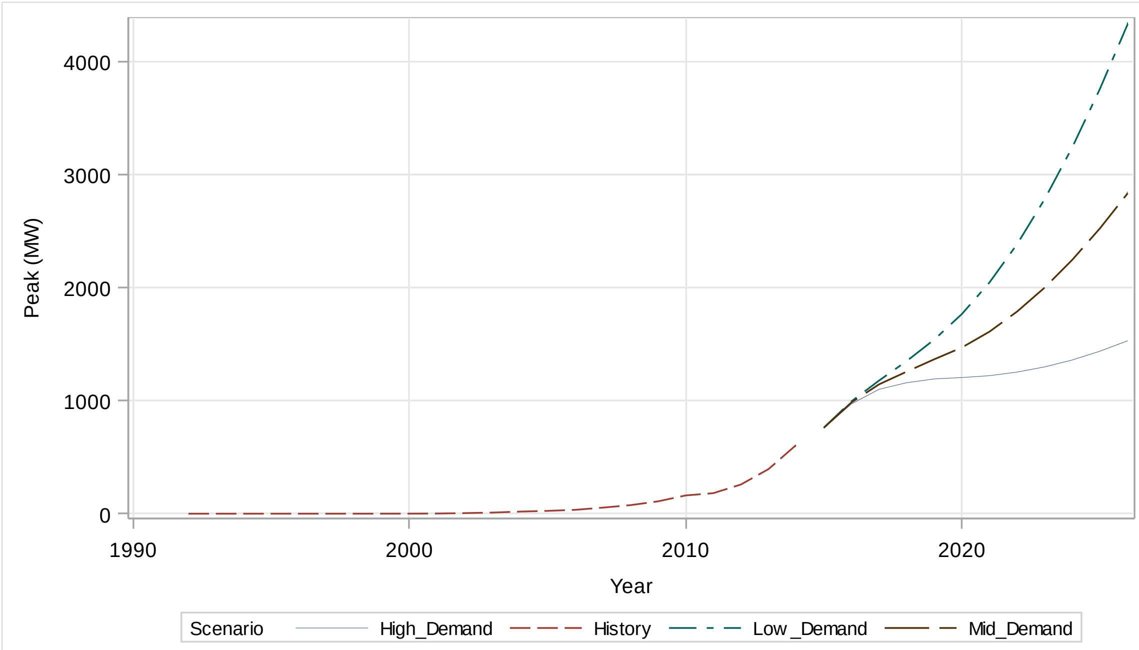
The adjustment to the PV peak factor is based on a retrospective assessment and does not account for potential shifts in the timing of the utility peak as additional behind-the-meter PV is added to the utility distribution system. Staff is making changes to the peak load model used to forecast long-term peak demand to account for these effects. An important step is to update the end-use load shapes used by the peak load model. It is anticipated that these changes will be ready for the *2017 IEPR* demand forecast. These updates are necessary to enable staff to conduct the "net load" analysis required as increasing amounts of behind-the-meter PV come on-line. Furthermore, staff is now required to quantify the effects of energy efficiency on an hourly basis; thus, updating the existing load shape database has become a high-priority task for staff.[97] Another change to the PV peak forecast for *CED 2015 Revised* was for each forecast year to consider the capacity added up to the month designated typical of when the utility system would peak rather than counting the annual capacity added as being available at the time of the system peak. For simplicity, staff applied a uniform monthly completion rate to implement this change in PV peak calculation.

Statewide Modeling Results

The following figures show results from the predictive models at the statewide level by demand case. **Figure B-11** shows the PV peak demand impact in the residential sector, which reaches more than 2,800 MW in the mid demand case and more than 4,300 MW in the low demand case by 2026. Additions decrease substantially with the expiration of the federal tax credit, which occurs in the middle of the forecast period, but then begin to increase as rates increase and PV installed costs decrease.

97 SB 350 Section 6 part E, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

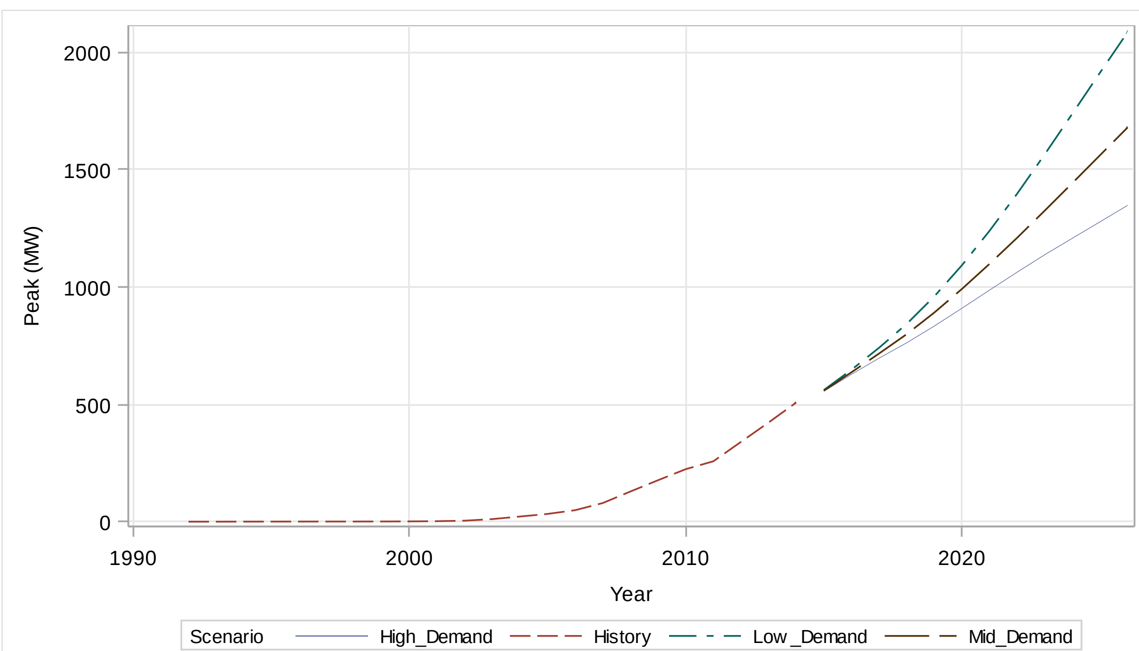
Figure B-11: Residential Sector PV Peak Impact, Statewide



Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-12 shows the PV peak demand impact for the nonresidential sector, which reaches just under 1,700 MW in the mid demand case and nearly 2,100 MW in the low demand case by 2026.

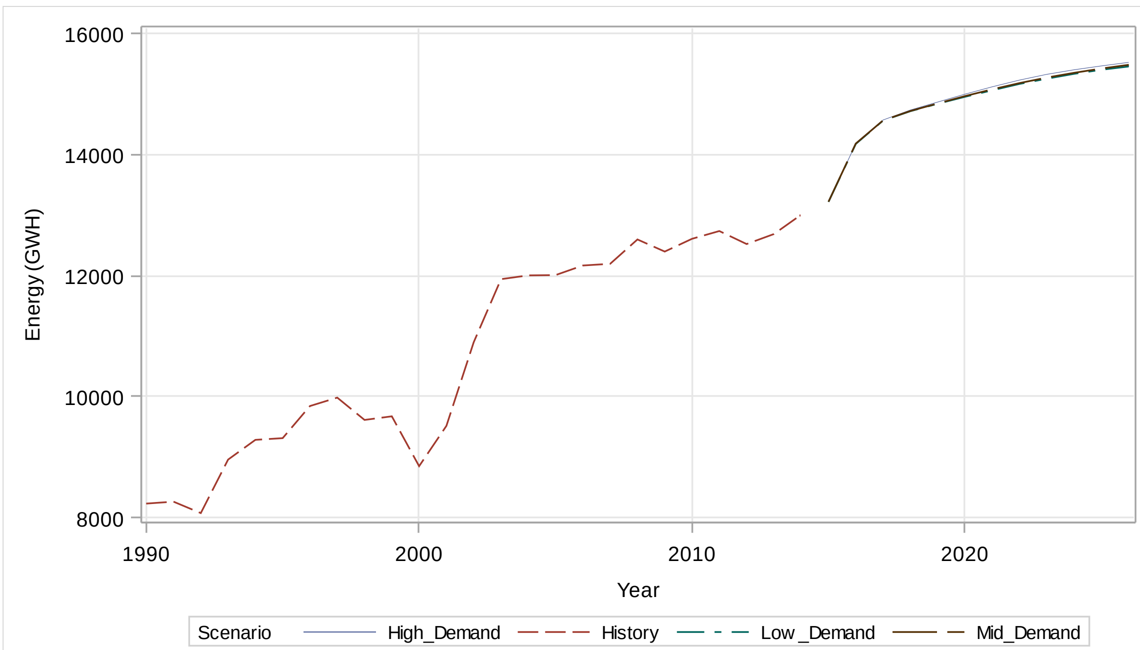
Figure B-12: Nonresidential Sector PV Peak Impact, Statewide



Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-13 shows the CHP energy impact for the nonresidential sector, which reaches more than 15,400 GWh by 2026 in all three cases. The rapid jump between 2012 and 2016 occurs because of the need to account for pending projects moving through the SGIP program. CHP additions in the SGIP slowed because of changes in program design, which limited participation mainly in fuel cells; SGIP now provides incentives for conventional CHP technologies, and this has led to many pending projects moving through the various application stages. However, pending modifications to SGIP could significantly limit participation for fossil-fueled CHP technologies.[98] Higher commercial floor space projections in the high demand case increase adoption relative to the other cases, while higher rates in the low case have the same effect. The net result is that all three cases are very similar throughout the forecast period, with the high demand case yielding slightly more impact than the mid and low cases.

Figure B-13: Nonresidential Sector CHP Energy Impact, Statewide



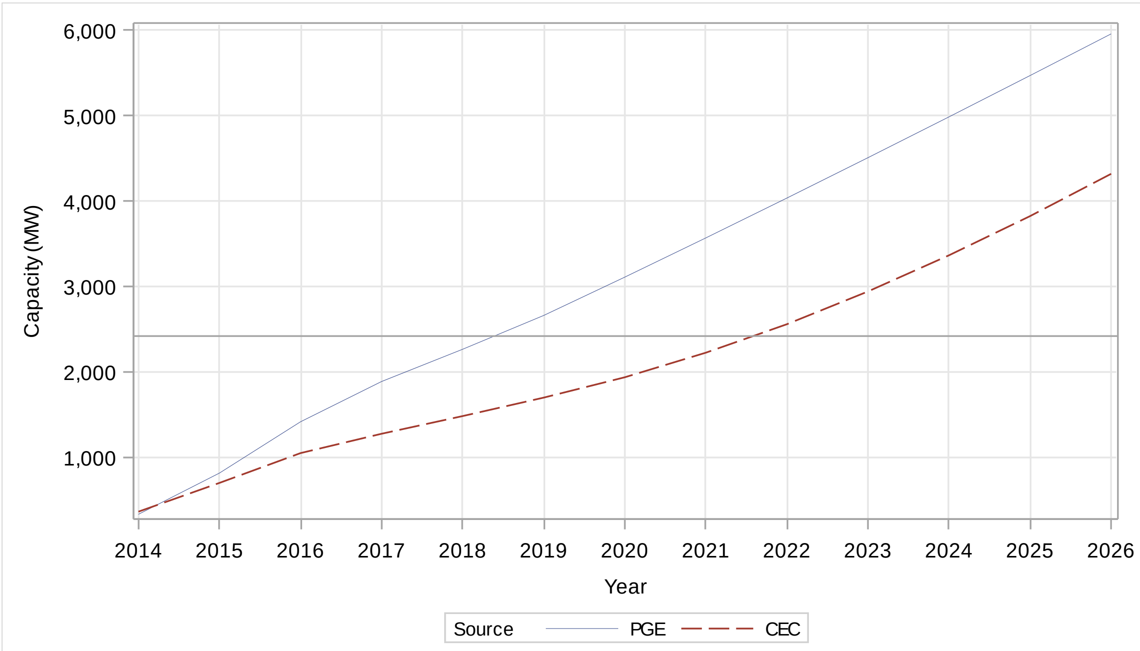
Source: California Energy Commission, Demand Analysis Office, 2015

As part of the regular IEPR data collection, each utility submits a long-term demand forecast that includes impacts of distributed generation, energy efficiency, and demand response programs.[99] **Figures B-14** through **B-16** compares the *CED 2015 Revised* mid demand case PV forecast to the PV forecast submitted by the investor-owned utilities (cumulative incremental to 2014). A horizontal reference line is drawn to represent the current NEM limit for each utility (5 percent of noncoincident peak demand).

98 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M153/K157/153157353.PDF.

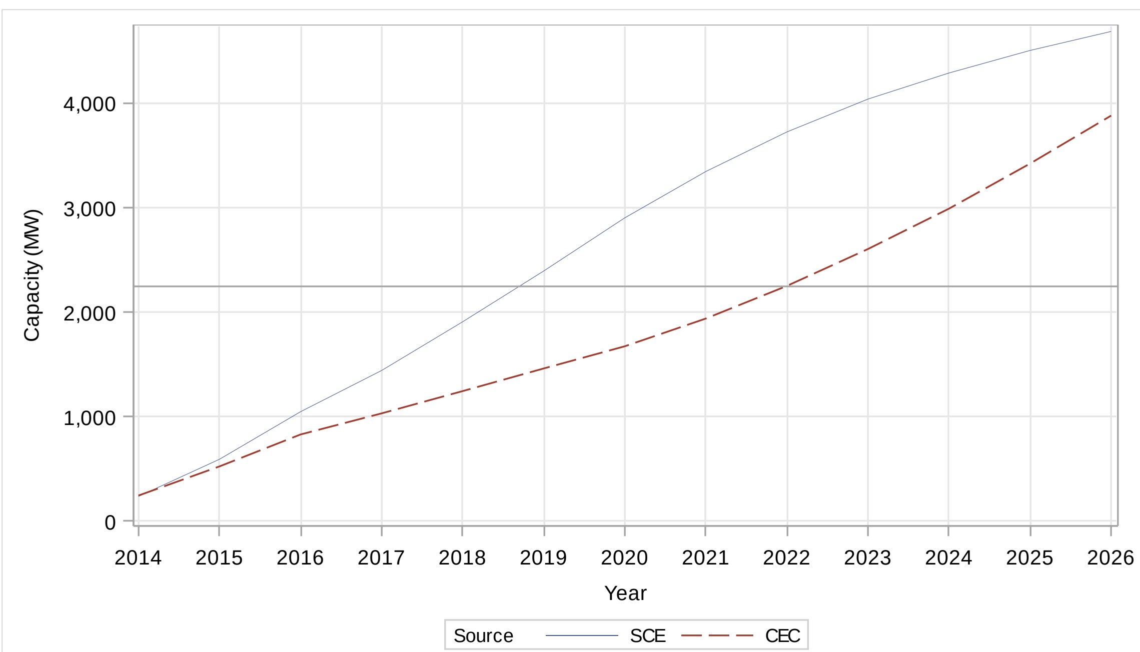
99 Staff obtained an updated PV forecast from Southern California Edison on 6/4/2015 with a much higher DG forecast than the one submitted as part of its IEPR filings.

Figure B-14: Comparison of PV Forecast, PG&E



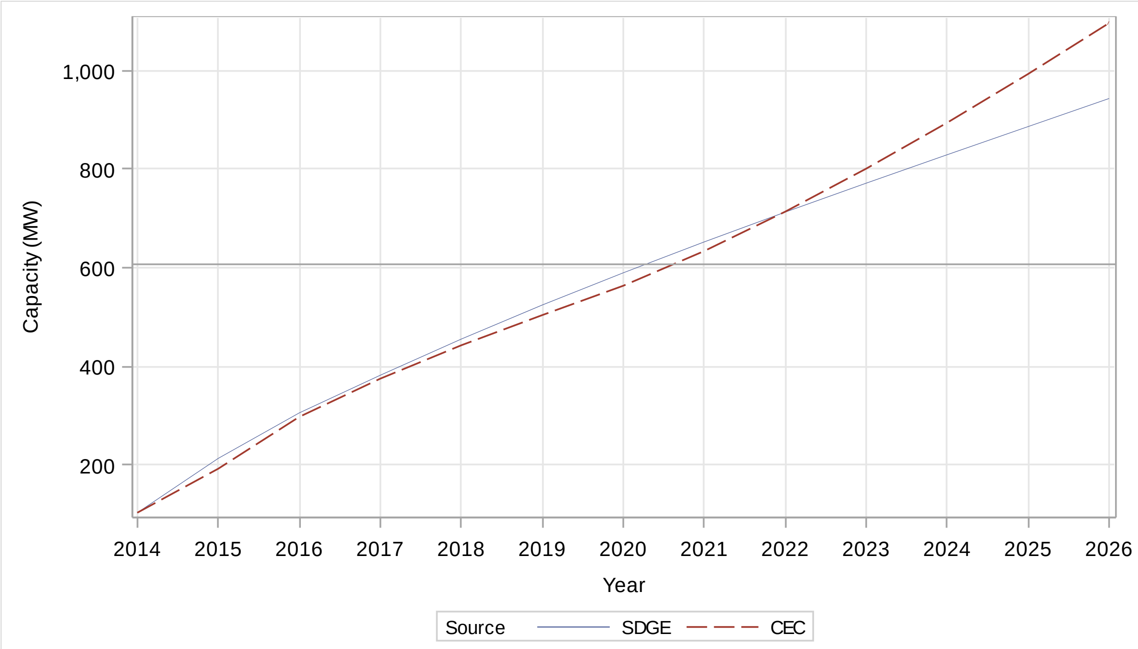
Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-15: Comparison of PV Forecast, SCE



Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-16: Comparison of PV Forecast, SDG&E



Source: California Energy Commission, Demand Analysis Office, 2015

Staff's forecast of PV adoption in the mid demand case is lower than PG&E's forecast over the forecast period and is nearly 1,600 MW lower by 2026. Staff's forecast of PV adoption is also lower for SCE by nearly 800 MW by 2026. Staff's forecast of PV adoption for SDG&E tends to be similar for SDG&E's forecast until 2020 and is higher than SDG&E's forecast by 150 MW by 2026. In general, both the utility and staff's forecasts expect future PV adoption to exceed the existing NEM limit.

Optional Scenario

At the request of the CPUC, staff also examined the relative difference in PV adoption from the mid demand case to a scenario requiring PV in new home construction. This option models the zero-net-energy home (ZNEH) work underway at the Energy Commission and the CPUC.[100] [101] For this scenario, staff limited its focus to single-family homes and assumed a nominal PV capacity of 2 kW per home. **Figure B-17** shows PV adoption relative to the mid demand case for various levels of PV penetration in new single-family construction (cumulative incremental to 2020).

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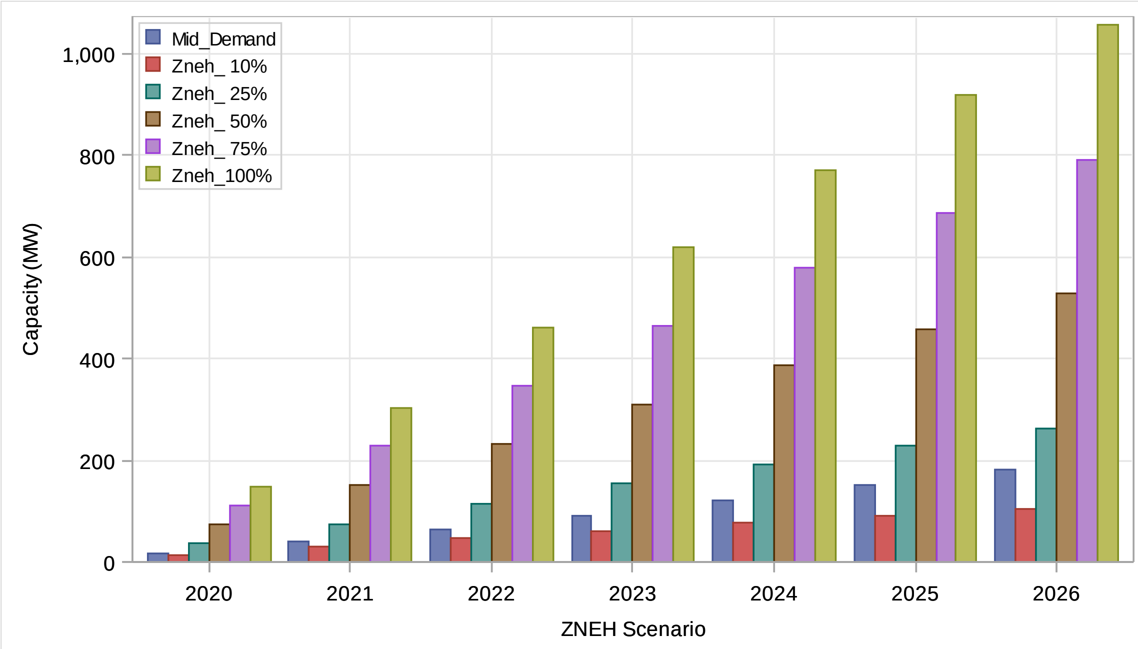
100 http://www.energy.ca.gov/2015_energypolicy/documents/2015-05-18_presentations.html.

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

Figure B-17: PV Adoption From Zero-Net-Energy Home Penetration



Source: California Energy Commission, Demand Analysis Office, 2015

Depending on the realized compliance with any regulation requiring PV in new single-family home construction, estimates of PV adoption can vary significantly. Housing starts in this period ranged from 70,000 to 80,000 units a year. Further, the ratcheting of energy efficiency standards toward preparation of a ZNEH standard will also affect PV system sizing, which will affect the cumulative market potential.

APPENDIX C: REGRESSION RESULTS

This appendix provides estimation results for the econometric models used in the analysis for *CED 2015 Revised*.

Table C-1: Residential Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Persons per Household	0.2345	0.1851	1.27
Per capita income (2014$)	0.1484	0.0549	2.70
Unemployment Rate	-0.0038	0.0011	-3.61
Residential Electricity Rate (2014¢/kWh)	-0.0828	0.0132	-6.29
Number of Cooling Degree Days (65^o)	0.0729	0.0066	11.08
Number of Heating Degree Days (65^o)	0.0502	0.0092	5.46
Dummy: 2001	-0.0548	0.0080	-6.85
Dummy: 2002	-0.0387	0.0080	-4.84
Constant: Burbank/Glendale	-0.5528	0.0161	-34.23
Constant: IID	0.1655	0.0265	6.24
Constant: LADWP	-0.5784	0.0154	-37.45
Constant: Pasadena	-0.6617	0.0276	-24.00
Constant: PG&E	-0.3491	0.0136	-25.75
Constant: SCE	-0.4736	0.0180	-26.32
Constant: SDG&E	-0.4528	0.0196	-23.13
Overall Constant	7.1881	0.4645	15.48
Trend Variables			
Time: Burbank/Glendale	0.0090	0.0019	4.70
Time Squared: Burbank/Glendale	-0.0001	0.0000	-2.03
Time: IID	0.0110	0.0039	2.84
Time Squared: IID	-0.0001	0.0001	-1.25
Time: LADWP	0.0068	0.0020	3.48
Time: Pasadena	0.0206	0.0031	6.57
Time Squared: Pasadena	-0.0003	0.0001	-3.34
Time: PG&E	0.0034	0.0018	1.90
Time Squared: PG&E	-0.0001	0.0000	-1.66
Time: SCE	0.0078	0.0020	3.87
Time Squared: SCE	-0.0001	0.0000	-1.60
Time: SDG&E	0.0032	0.0012	2.81
Time: SMUD	-0.0014	0.0010	-1.43
Adjusted for autocorrelation and cross-sectional correlation. Wald chi squared = 15,511 Dependent variable = natural log of electricity consumption per household by planning area, 1980-2014 All variables in logged form except time and unemployment rate.			

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

Table C-2: Commercial Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Commercial Employment	0.8248	0.0119	69.59
Commercial Electricity Rate (2013¢/kWh)	-0.0161	0.0132	-1.23
Number of Cooling Degree Days (65^{o})	0.0464	0.0082	5.69
Dummy: 2001 (LADWP)	-0.0485	0.0222	-2.18
Dummy: 2001 (PG&E)	-0.0391	0.0152	-2.56
Dummy: 2001 (SDG&E)	-0.0682	0.0167	-4.09
Constant: Burbank	-0.2164	0.0303	-7.15
Constant: LADWP	0.1795	0.0230	7.80
Constant: PG&E	0.2388	0.0316	7.55
Constant: SCE	0.2737	0.0278	9.84
Overall Constant	2.6479	0.1052	25.17
Trend Variables			
Time: Burbank	0.0460	0.0037	12.51
Time Squared: Burbank	-0.0009	0.0001	-8.98
Time: IID	0.0321	0.0033	9.62
Time Squared: IID	-0.0006	0.0001	-6.31
Time: LADWP	0.0192	0.0028	6.94
Time Squared: LADWP	-0.0004	0.0001	-5.39
Time: PASD	0.0311	0.0089	3.49
Time Squared: PASD	-0.0004	0.0003	-1.49
Time: PG&E	0.0235	0.0015	15.22
Time Squared: PG&E	-0.0003	0.0000	-8.09
Time: SCE	0.0188	0.0012	15.75
Time Squared: SCE	-0.0002	0.0000	-7.73
Time: SDG&E	0.0211	0.0021	10.01
Time Squared: SDG&E	-0.0003	0.0001	-6.35
Time: SMUD	0.0068	0.0009	7.54
Adjusted for autocorrelation and cross-sectional correlation. Wald chi squared = 278,879 Dependent variable = natural log of commercial consumption by planning area, 1980-2013. All variables in logged form except time.			

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

Table C-3: Manufacturing Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Manufacturing Output (million 2013$)	0.4958	0.0548	9.04
Manufacturing Output/Manufacturing Employment	-0.3474	0.0433	-8.02
Output Textiles, Fiber, Printing/Manufacturing Output	0.6708	0.3113	2.16
Output Chemicals, Energy, Plastic/Manufacturing Output	-0.3426	0.1173	-2.92
Industrial Electricity Rate (2013¢/kWh)	-0.1092	0.0227	-4.82
Constant: Burbank/Glendale	0.5295	0.1589	3.33
Constant: IID	-0.2932	0.2225	-1.32
Constant: LADWP	1.2849	0.2059	6.24
Constant: PASD	-0.4812	0.1595	-3.02
Constant: PG&E	2.5460	0.2429	10.48
Constant: SCE	2.3752	0.2544	9.34
Constant: SDG&E	0.4814	0.1660	2.90
Overall Constant	3.8803	0.2654	14.62
Trend Variables			
Time: Burbank/Glendale	-0.0430	0.0060	-7.16
Time: IID	-0.0584	0.0172	-3.41
Time Squared: IID	0.0022	0.0005	4.72
Time: Pasadena	-0.0713	0.0153	-4.66
Time Squared: Pasadena	0.0008	0.0004	2.00
Time: PG&E	-0.0044	0.0021	-2.04
Time: SDG&E	0.0376	0.0042	9.01
Time Squared: SDG&E	-0.0010	0.0001	-10.29
Time: SMUD	0.0795	0.0144	5.52
Time Squared: SMUD	-0.0017	0.0004	-4.50
Adjusted for autocorrelation and cross-sectional correlation. Wald chi squared = 36,517 Dependent variable = natural log of industrial consumption by planning area, 1980-2013. All variables in logged form except time, output textiles, fiber, printing/manufacturing output and output chemicals, energy, plastic/manufacturing output.			

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

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

Variable	Estimated Coefficient	Standard Error	t-statistic
Output, Resource Extraction (million 2009$)	0.1299	0.0402	3.23
Employment in Construction (thousands)	0.2293	0.0821	2.79
Percent Employment Resource Extraction	2.3129	0.9555	2.42
Industrial Electricity Rate (2013 cents/kWh)	-0.1250	0.0614	-2.04
Dummy: 2002	-0.0661	0.0320	-2.06
Dummy: 1997 SDG&E	-1.0680	0.0881	-12.12
Dummy: 1980 and 1981 PG&E	-1.0468	0.0722	-14.50
Constant: BUGL	-1.2298	0.1564	-7.86
Constant: IID	-1.4130	0.2970	-4.76
Constant: LADWP	1.0914	0.2571	4.25
Constant: PASD	-3.5856	0.3143	-11.41
Constant: PG&E	2.9873	0.3913	7.63
Constant: SCE	2.9109	0.3675	7.92
Overall Constant	2.8931	0.3097	9.34
Trend Variables			
Time: BUGL	0.1148	0.0110	10.40
Time squared: BUGL	-0.0025	0.0003	-9.12
Time: IID	0.1105	0.0307	3.60
Time squared: IID	-0.0015	0.0008	-1.81
Time: PASD	0.3237	0.0351	9.22
Time squared: PASD	-0.0083	0.0010	-8.64
Time: PG&E	-0.0234	0.0148	-1.58
Time squared: PG&E	0.0008	0.0004	1.96
Time: SDG&E	0.1115	0.0282	3.96
Time Squared: SDG&E	-0.0027	0.0008	-3.58
Time: SMUD	0.0698	0.0166	4.22
Time Squared: SMUD	-0.0013	0.0004	-2.92
Adjusted for autocorrelation and cross-sectional correlation. Wald chi squared = 33,042 Dependent variable = natural log of construction & resource extraction consumption by planning area 1980-2013. All variables in logged form except time and percentage employment resource extraction.			

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

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

Variable	Estimated Coefficient	Standard Error	t-statistic
Agricultural Electricity Rate (2013 cents/kWh)	-0.1146	0.0704	-1.63
Agricultural Output per Capita	0.0718	0.0601	1.19
Precipitation (inches)	-0.0519	0.0140	-3.71
Constant: Burbank/Glendale	-1.2549	0.1753	-7.16
Constant: IID	1.6332	0.1520	10.74
Constant: LADWP	-1.0859	0.1594	-6.81
Constant: PG&E	1.6636	0.1068	15.58
Constant: SCE	1.0948	0.1165	9.40
Overall Constant	5.1464	0.4169	12.34
Trend Variables			
Time: IID	0.0179	0.0047	3.79
Time Squared: IID	-0.0006	0.0001	-4.75
Time: LADWP	0.0304	0.0122	2.49
Time Squared: LADWP	-0.0010	0.0003	-3.09
Time: PG&E	-0.0324	0.0069	-4.71
Time Squared: PG&E	0.0007	0.0002	3.74
Time: SDG&E	-0.0660	0.0112	-5.88
Time Squared: SDG&E	0.0018	0.0003	5.34
Adjusted for autocorrelation and cross-sectional correlation. Wald chi squared = 20,066 Dependent variable = natural log of agriculture and water pumping electricity consumption per capita by planning area 1980-2013. All variables in logged form except time.			

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

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

Variable	Estimated Coefficient	Standard Error	t-statistic
Commercial Electricity Rate (2013 cents/kWh)	-0.2165	0.0472	-4.58
Per capita income (2013$)	0.0760	0.0483	1.57
Constant: Burbank/Glendale	-1.6606	0.1152	-14.42
Constant: IID	0.9813	0.1584	6.20
Constant: LADWP	-0.3759	0.0536	-7.01
Constant: Pasadena	-1.2221	0.0633	-19.31
Constant: PG&E	-0.1377	0.0442	-3.12
Constant: SCE	-0.4904	0.0397	-12.35
Constant: SDG&E	-0.0801	0.0428	-1.87
Overall Constant	6.1373	0.5083	12.07
Trend Variables			
Time Squared: BUGL	0.0032	0.0004	8.27
Time: IID	-0.0559	0.0102	-5.50
Time: Pasadena	0.0480	0.0135	3.56
Time Squared: PASD	-0.0013	0.0005	-2.42
Time: PG&E	-0.0362	0.0041	-8.84
Time Squared: PG&E	0.0014	0.0001	9.23
Time: SMUD	-0.0438	0.0073	-5.99
Time Squared: SMUD	0.0009	0.0003	2.99
Adjusted for autocorrelation and cross-sectional correlation. Wald chi squared = 2,693 Dependent variable = natural log of TCU electricity consumption per capita by planning area 1990-2013. All variables in logged form except time.			

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

Table C-7: Street Lighting Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Per Capita Income (2013$)	0.2408	0.0892	2.70
Constant: Burbank/Glendale	-1.0794	0.0723	-14.93
Constant: IID	-2.6927	0.1659	-16.23
Constant: LADWP	1.2344	0.1054	11.72
Constant: Pasadena	-1.2730	0.0501	-25.41
Constant: PG&E	1.7199	0.0453	37.97
Constant: SCE	1.9387	0.0773	25.07
Overall Constant	6.6419	0.9264	7.17
Trend Variables			
Time Squared: BUGL	-0.0003	0.0002	-1.17
Time: IID	0.1080	0.0295	3.66
Time Squared: IID	-0.0028	0.0011	-2.47
Time: LADWP	0.0639	0.0177	3.60
Time Squared: LADWP	-0.0038	0.0007	-5.71
Time: Pasadena	0.0091	0.0030	3.00
Time: PG&E	0.0065	0.0064	1.01
Time Squared: PG&E	-0.0005	0.0002	-2.54
Time: SCE	0.0189	0.0101	1.87
Time Squared: SCE	-0.0011	0.0004	-2.92
Time: SDG&E	0.0233	0.0049	4.78
Time: SMUD	0.0211	0.0056	3.76
Time Squared: SMUD	-0.0007	0.0002	-3.53
Adjusted for autocorrelation and cross-sectional correlation. Wald chi squared = 48,785 Dependent variable = natural log of street lighting electricity consumption by planning area 1990-2013 All variables in logged form except time.			

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

Table C-8: Peak Demand Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Per Capita Income (2013$)	0.1579	0.0340	4.65
Unemployment Rate	-0.0027	0.0011	-2.58
Persons per Household	-0.6911	0.1787	-3.87
Residential Electricity Rate	-0.0252	0.0239	-1.05
Commercial Electricity Rate	-0.0279	0.0169	-1.66
Annual Max *Average631* Temperature	1.0633	0.0557	19.11
Residential Consumption per Capita	0.2083	0.0344	6.05
Commercial Consumption per Capita	0.1095	0.0261	4.20
Dummy: 2001	-0.0616	0.0111	-5.57
Constant: IID	0.1902	0.0410	4.64
Constant: LADWP	-0.1696	0.0150	-11.28
Constant: Pasadena	-0.0996	0.0154	-6.48
Constant: PG&E	-0.1671	0.0135	-12.39
Constant: SCE	-0.1246	0.0187	-6.66
Constant: SDG&E	-0.4339	0.0197	-22.03
Overall Constant	-7.4037	0.4035	-18.35
Trend Variables			
Time: Burbank/Glendale	0.0035	0.0007	5.07
Time: Imperial Irrigation District	0.0020	0.0008	2.57
Time: LADWP	0.0048	0.0016	2.95
Time Squared: LADWP	-0.0001	0.0000	-2.85
Time: Pasadena	0.0216	0.0018	11.80
Time Squared: Pasadena	-0.0005	0.0000	-11.09
Time: SCE	0.0038	0.0019	2.00
Time Squared: SCE	-0.0001	0.0000	-1.85
Time: SDG&E	0.0058	0.0007	8.51

Adjusted for autocorrelation and cross-sectional correlation.

Wald chi squared = 25,433

Dependent variable = natural log of annual peak per capita by planning area, 1980-2013.

All variables in logged form except time and unemployment rate.

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

APPENDIX D: CALIFORNIA INDUSTRIAL SECTOR ELECTRICITY TRENDS

Introduction

This appendix is the first attempt by Energy Commission staff to analyze trends in California's industrial sector and contains two key analyses. The first is an analysis based on electricity consumption (**Table D-2**) that categorizes the industrial sector into six categories. This is necessary to identify which industries have the greatest and the least energy consumption in the industrial sector as a whole.

The second analysis (**Table D-3**) categorizes each industry into one of three growth categories based on annual growth rates for the forecast years of 2013 through 2024. The industry growth rates in conjunction with the Pareto Analysis indicate the effects of how various-sized industries compare with various growth rates (for example, how a small industry with a large growth rate compares to a large industry with a small growth rate). The results of the combined analyses show that the sector as a whole is generally stable due to the stable growth rates of the largest industries.

The historical data in this study was obtained through 2012, which is not as recent as the historical data used in the most recent California Energy Demand 2016-2026 forecast. Energy Commission staff will consider revising this section in the future with more current data.

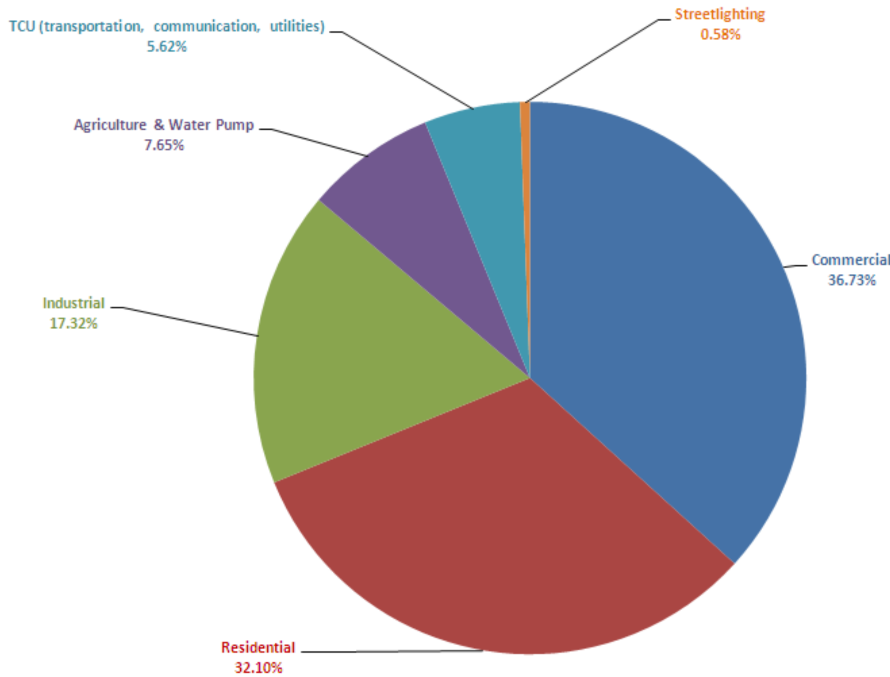
Electricity Consumption in California

The Energy Commission requires 56 load-serving entities (LSE)[102] in the state to file QFER[103] documenting retail energy sales by specific industries. Industrial electricity consumption is the combination of onsite electricity cogeneration and QFER electricity sales. Based on 2012 electricity consumption, the industrial sector is the third largest user of electricity in California among the six major economic sectors, accounting for 17 percent of total electricity use, such as in **Figure D-1**.

102 *Load-serving entity* is any company that sells or provides electricity to end users located in California. Included are investor owned and publicly owned companies, energy service providers, community choice aggregators, and water agencies.

103 Under the Energy Commission's Quarterly Fuel and Energy Report (QFER) regulations, each load-serving entity (LSE) is required to file quarterly reports documenting energy consumption by activity group.

Figure D-1: Sector Shares of Total Electricity Consumption (2012)



Source: California Energy Commission staff

Industrial Sector North American Industry Classification Categories

The California industrial sector consists of 28 industry NAICS groups. In a few cases, industries that use similar processes are combined. For example, food and beverage (NAICS 3113 and 3114) are combined into a single NAICS group due to similar processes. For this report, the 28 industry groups are categorized as either "manufacturing" or "mining and construction," as shown in **Table D-1**.

Differences in economic drivers create the need to separate the two categories. Projections of industrial electricity use for the "manufacturing" category are driven by gross state product (GSP), while the "mining and construction" category are driven by employment. Price volatility of commodities such as oil, natural gas, and precious metals leads to instability in shipment values or gross domestic product (GDP). This volatility distorts the empirical relationship between the value of production and the energy required in extraction.

Table D-1: Industry NAICS Groups

Sub-Groups	#	NAICS	Industries
Mining	*1*	211, 213	Oil and Gas Extraction & Support Activities
Mining	*2*	212	Other Mining
Construction	*3*	230	Construction
Manufacturing	*4*	311x, 312	Food Processing
Manufacturing	*5*	3113, 3114	Food & Beverage
Manufacturing	*6*	313	Textile Mills
Manufacturing	*7*	314	Textile Product Mills
Manufacturing	*8*	315, 316	Apparel & Leather Product Manufacturing
Manufacturing	*9*	1133, 321	Logging & Wood Product Manufacturing
Manufacturing	*10*	322x	Pulp, Paper, and Paperboard Mills
Manufacturing	*11*	3221	Paper Manufacturing (excl. Mills)
Manufacturing	*12*	323	Printing and Related Support Activities
Manufacturing	*13*	324	Petroleum and Coal Products Manufacturing
Manufacturing	*14*	325	Chemical Manufacturing
Manufacturing	*15*	326	Plastics and Rubber Products Manufacturing
Manufacturing	*16*	327x	Nonmetallic Mineral Product Manufacturing (excl. glass and cement)
Manufacturing	*17*	3272	Glass Manufacturing
Manufacturing	*18*	3273	Cement
Manufacturing	*19*	331	Primary Metal Manufacturing
Manufacturing	*20*	332	Fabricated Metal Product Manufacturing
Manufacturing	*21*	333	Machinery Manufacturing
Manufacturing	*22*	334x	Semiconductor and Other Electronic Component Manufacturing
Manufacturing	*23*	3344	Computer and Electronic Product Manufacturing
Manufacturing	*24*	335	Electrical Equipment, Appliance, and Component Manufacturing
Manufacturing	*25*	336	Transportation Equipment Manufacturing
Manufacturing	*26*	337	Furniture and Related Product Manufacturing
Manufacturing	*27*	339	Miscellaneous Manufacturing
Manufacturing	*28*	511, 516	Publishing Industries (except Internet)

Source: California Energy Commission staff

Industrial Electricity Consumption Trends

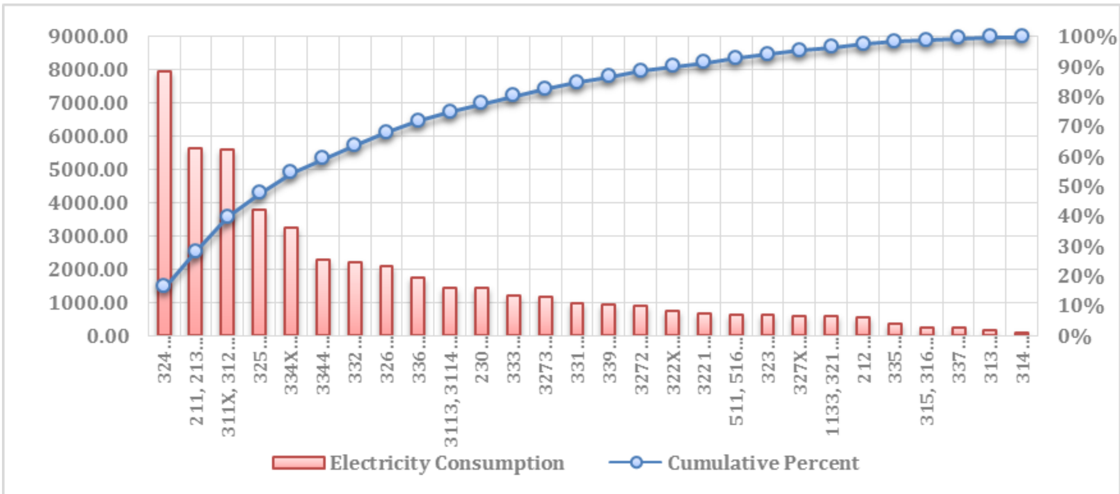
Table D-2 illustrates that the largest five industry groups consume nearly 55 percent of total industrial electricity, and that the 10 largest industry groups consume nearly 75 percent of total industrial electricity. **Table D-2** also separates the 28 industry groups into six categories to reduce scaling error in the upcoming series of electricity consumption graphs (**Figures D-2** through **D-8**). Each of the six categories and the related electricity consumption graphs will be discussed later in the report.

Table D-2: Industrial Electricity Use – Largest to Smallest (2012)

NAICS	Industry	GWh/Yr	Percentage	Cumulative Percentage	Consumption Categories
324	Petroleum and Coal Products Manufacturing	7959.39	16.54%	16.54%	Category 1 (between 3000 and 8000 GWh)
211, 213	Oil and Gas Extraction & Support Activities	5625.65	11.69%	28.24%	
311x, 312	Food Processing	5590.79	11.62%	39.86%	
325	Chemical Manufacturing	3782.79	7.86%	47.72%	
334x	Semiconductor and Other Electronic Component	3257.82	6.77%	54.49%	
3344	Computer and Electronic Product Manufacturing	2291.43	4.76%	59.25%	Category 2 (between 1700 and 3000 GWh)
332	Fabricated Metal Product Manufacturing	2196.67	4.57%	63.82%	
326	Plastics and Rubber Products Manufacturing	2072.13	4.31%	68.12%	
336	Transportation Equipment Manufacturing	1746.87	3.63%	71.75%	
3113, 3114	Food & Beverage	1441.55	3.00%	74.75%	Category 3 (between 1200 and 1700 GWh)
230	Construction	1437.47	2.99%	77.74%	
333	Machinery Manufacturing	1197.62	2.49%	80.23%	
3273	Cement	1182.72	2.46%	82.69%	
331	Primary Metal Manufacturing	957.83	1.99%	84.68%	Category 4 (between 700 and 1200 GWh)
339	Miscellaneous Manufacturing	950.54	1.98%	86.65%	
3272	Glass Manufacturing	905.39	1.88%	88.53%	
322x	Pulp, Paper, and Paperboard Mills	734.08	1.53%	90.06%	
3221	Paper Manufacturing (excl. Mills)	648.41	1.35%	91.41%	Category 5 (between 500 and 700 GWh)
511, 516	Publishing Industries (except Internet)	641.39	1.33%	92.74%	
323	Printing and Related Support Activities	633.72	1.32%	94.06%	
327x	Nonmetallic Mineral Product Manufacturing	601.95	1.25%	95.31%	
1133, 321	Logging & Wood Product Manufacturing	574.56	1.19%	96.50%	
212	Other Mining	564.31	1.17%	97.68%	
335	Electrical Equipment, Appliance, and Component	375.25	0.78%	98.46%	Category 6 (between 0 and 500 GWh)
315, 316	Apparel & Leather Product Manufacturing	253.97	0.53%	98.98%	
337	Furniture and Related Product Manufacturing	253.04	0.53%	99.51%	
313	Textile Mills	166.25	0.35%	99.86%	
314	Textile Product Mills	69.58	0.14%	100.00%	

Source: California Energy Commission staff

Figure D-2: Industrial Electricity Use (2012 GWh)



Source: California Energy Commission Staff

The following graphs (**Figures D-2** through **D-8**) show industrial electricity consumption trends for the six consumption categories shown in **Table D-2**. Electricity consumption trends use QFER data and the *2013 Integrated Energy Policy Report* (*2013 IEPR*)[104] mid case (baseline) industrial sector forecast.[105]

Figure D-3 shows electricity consumption trends for the five industries listed in Consumption Category 1 (between 3,000 and 8,000 GWh). Modest growth is expected to continue in the chemical manufacturing sector, while petroleum and coal products manufacturing, oil and gas extraction, food manufacturing, and semiconductor and electronic component manufacturing industries are expected to experience decreased consumption over the forecast horizon.

Increased fuel prices and end-use efficiency gains drive the declining electricity consumption forecast for petroleum and coal products manufacturing, oil and gas extraction, food processing, and semiconductor and other electronic component manufacturing. For chemical manufacturing, increasing fuel prices and end-use efficiency gains reduce electricity consumption; however, the overall trend reflects a slight growth because the economic output for chemical manufacturing is expected to increase significantly during the forecast period.

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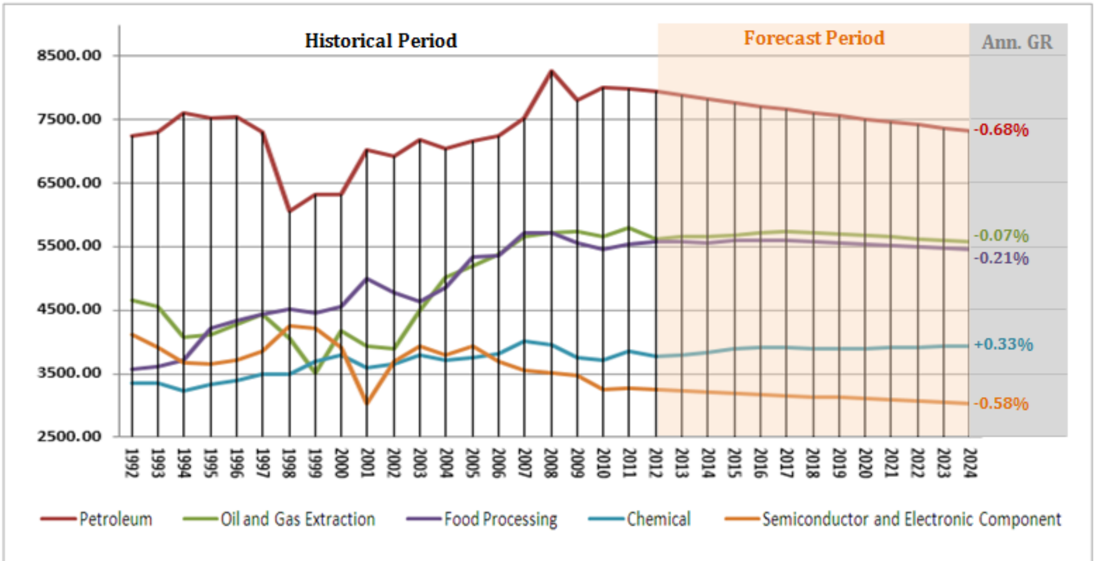
104 www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/LSE_and_Balancing_Authority_Forecasts/.

105 The forecast trends do not include the additional achievable energy efficiency estimates developed by the three major investor owned utilities (PG&E, SCE and SDG&E). These savings are not considered committed but are reasonably likely to occur and include impacts from future updates of building codes and appliance standards, as well as utility efficiency programs expected to continue beyond the current planning cycle.

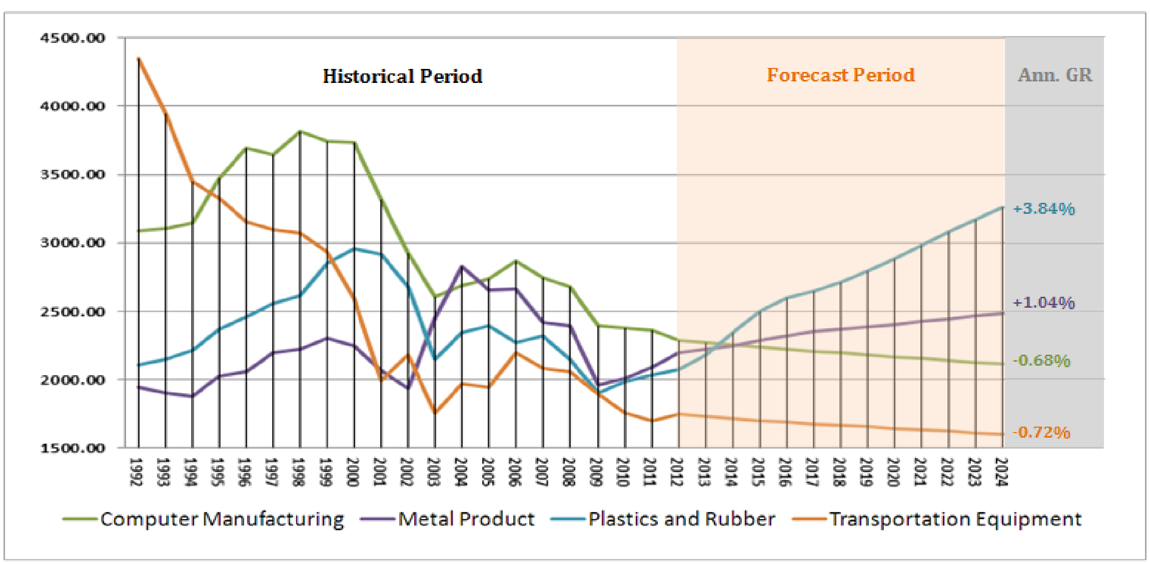
Figure D-3: Consumption Category 1
Industrial Electricity Consumption Trends (Between 3,000 and 8,000 GWh)



Source: California Energy Commission staff

Figure D-4 illustrates electricity consumption trends for the four industries in Consumption Category 2 (between 1,700 and 3,000 GWh). Of these industrial sectors, plastic and rubber manufacturing is expected to experience the most growth, metal product manufacturing is also expected to be a growth industry, while computer manufacturing and transportation equipment manufacturing are expected to continue a slow decline.

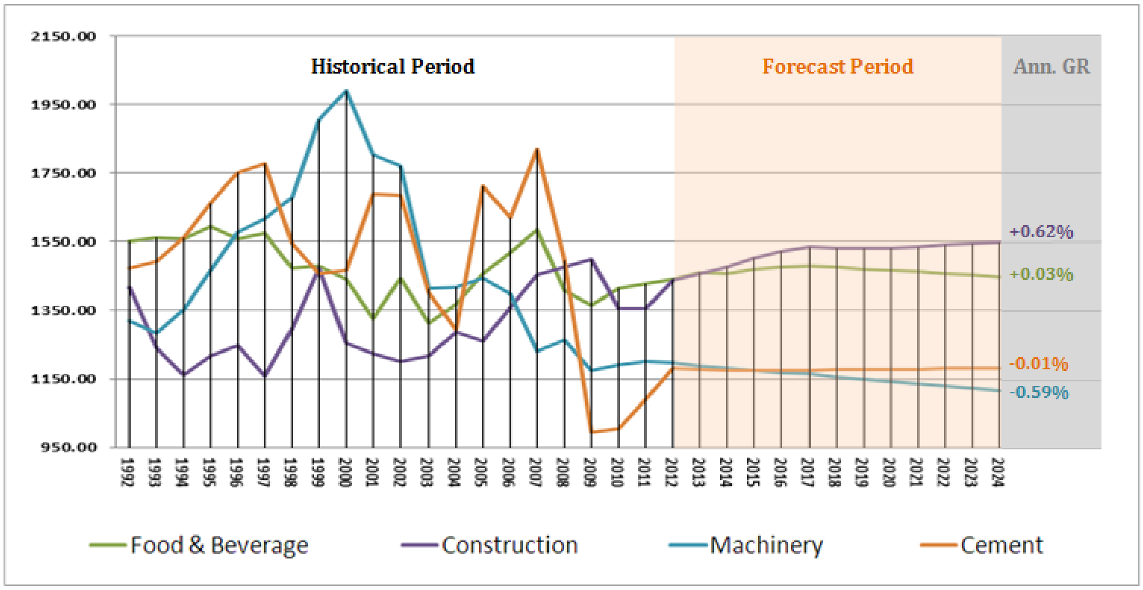
Figure D-4: Consumption Category 2
Industrial Electricity Consumption Trends (Between 1,700 and 3,000 GWh)



Source: California Energy Commission staff

Figure D-5 illustrates electricity consumption trends for the four industries in the consumption category 3 (between 1,200 and 1,700 GWh). The construction industry is expected to experience moderate growth, while the machinery industry is expected to continue a slow decline. Change in consumption in the food and beverage and cement manufacturing sectors are expected to be insignificant.

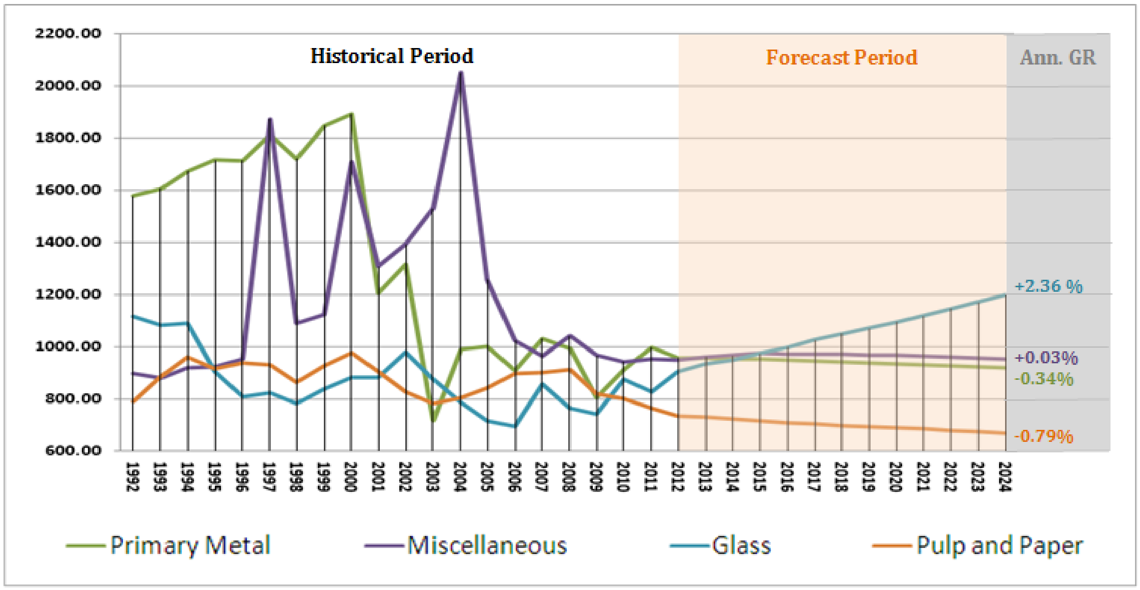
Figure D-5: Consumption Category 3
Industrial Electricity Consumption Trends (Between 1,200 and 1,700 GWh)



Source: California Energy Commission staff

Figure D-6 depicts electricity consumption trends for the four industries in Consumption Category 4 (between 700 and 1,200 GWh). Glass manufacturing is one of the industries expected to experience increased electricity consumption in the coming years. The remaining three industries in this category are expected to increase slightly or continue a slow decline.

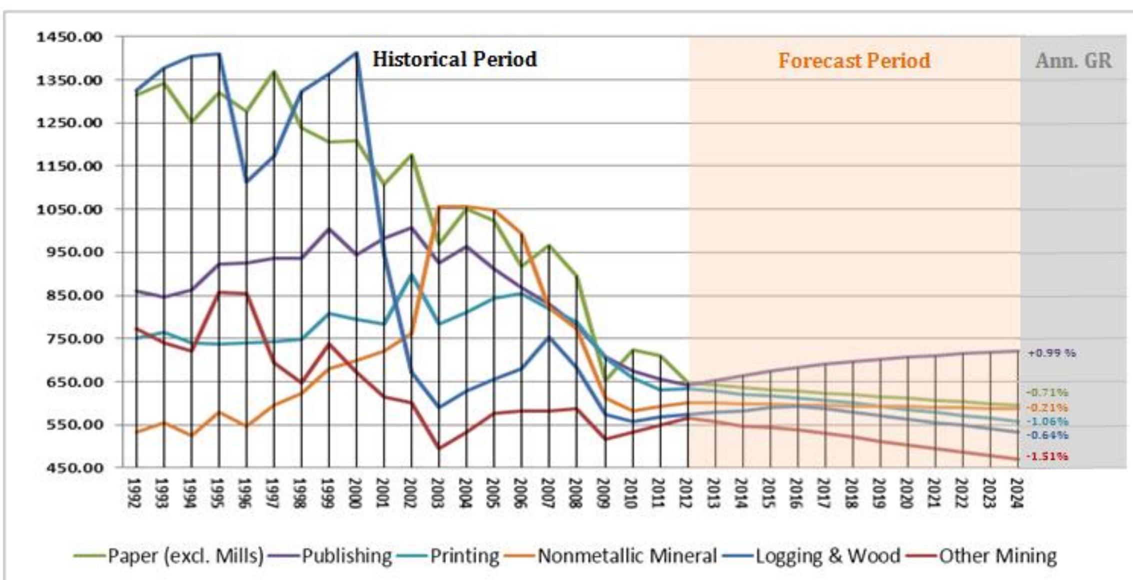
Figure D-6: Consumption Category 4
Industrial Electricity Consumption Trends (Between 700 and 1,200 GWh)



Source: California Energy Commission staff

Figure D-7 shows electricity consumption trends for the six industries in Consumption Category 5 (between 500 and 700 GWh/yr). The publishing industry projects an increasing annual growth rate in comparison to the decreasing growth rates of the remaining industries in this category.

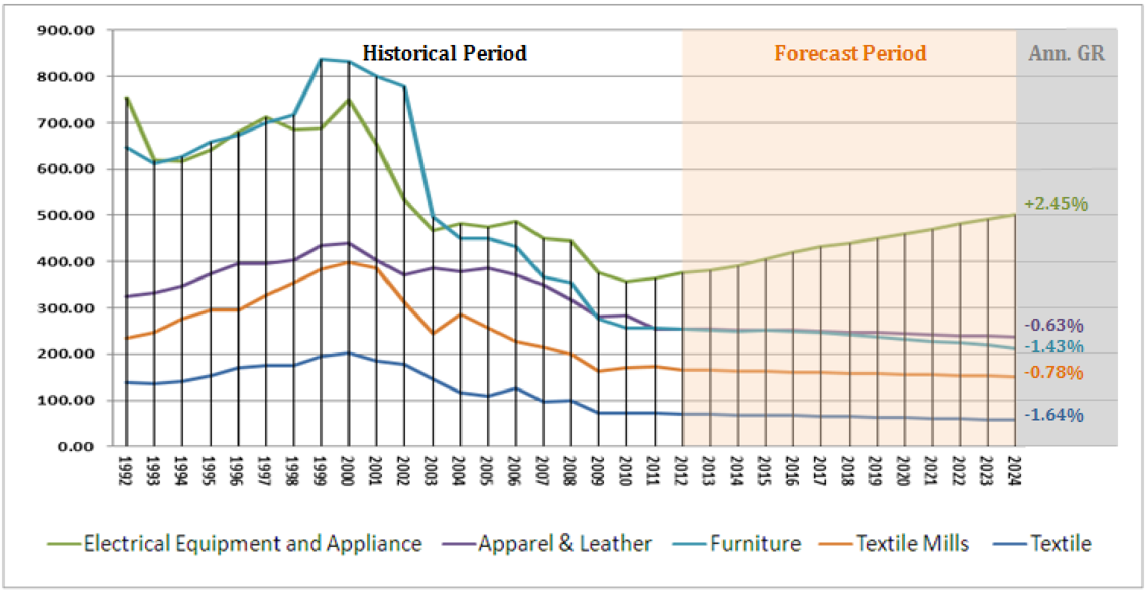
Figure D-7: Consumption Category 5
Industrial Electricity Consumption Trends (Between 500 and 700 GWh)



Source: California Energy Commission staff

Figure D-8 shows electricity consumption trends for the five industries in Consumption Category 6 (between 0 and 500 GWh). Electrical equipment and appliance manufacturing is the only industry with an increasing annual growth rate in comparison with the remaining industry groups with decreasing electricity consumption in this category.

Figure D-8: Consumption Category 6
Industrial Electricity Consumption Trends (Between 0 and 500 GWh)



Source: California Energy Commission staff

Statewide Industrial Electricity Growth

Table D-3 categorizes each of the 28 industry groups into three categories: increasing, stable, and decreasing annual growth rates for the forecast years of 2013 through 2024.

Interestingly, three of the five largest industries in California, chemical manufacturing, oil and gas extraction, and food processing, fall into the "stable" category. The remaining two large industries fall into the "decreasing" growth category.

The forecast predicts that of the 28 industry groups, six industries (representing about 16 percent of 2012 industrial sector electricity consumption) will experience increasing annual growth rates, while 14 industries (representing approximately 42 percent of 2012 electricity consumption) will see decreasing annual growth rates. The remaining eight industries (about 42 percent of 2012 electricity consumption) are predicted to experience stable annual growth.

The industries with the largest expected growth between 2013 and 2024 are plastic and rubber manufacturing (3.84 percent), electrical equipment and appliance manufacturing (2.45 percent), and glass manufacturing (2.36 percent). Of these industries, plastics and rubber manufacturing comprises the eighth largest share of total industrial sector electricity consumption. Glass manufacturing has the sixteenth largest share of total electricity consumption, and electrical equipment and appliance manufacturing holds the twenty-fourth largest share.

The industries with the largest expected decline between 2013 and 2024 are textile product mills (1.64 percent), other mining (1.51 percent), and furniture manufacturing (1.43 percent). These three industries consume small shares of total electricity consumption in the industrial sector.

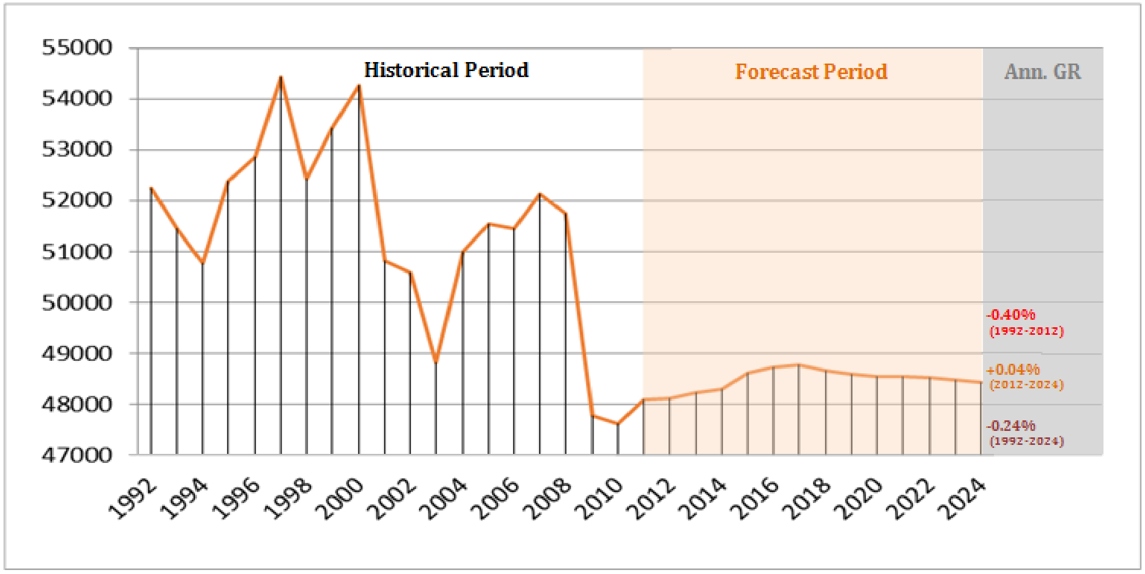
Table D-3: Industrial Electricity Annual Growth Rate – Largest to Smallest (2012 to 2024)

NAICS	Industries	Consumption % Share (2012)	Consumption % Range (2012)	Annual Growth Rate %	Growth Categories
326	Plastics and Rubber	4.31%	15.85% (7628.31 GWh)	3.84%	Increasing (between +0.05% and +4.00%)
335	Electrical Equipment and Appliance	0.78%		2.45%	
3272	Glass	1.88%		2.36%	
332	Metal Product	4.57%		1.04%	
511, 516	Publishing	1.33%		0.99%	
230	Construction	2.99%		0.62%	
325	Chemical	7.86%	41.85% (20133.82 GWh)	0.33%	Stable (between -0.50% and +0.50%)
339	Miscellaneous	1.98%		0.03%	
3113, 3114	Food & Beverage	3.00%		0.03%	
3273	Cement	2.46%		-0.01%	
211, 213	Oil and Gas Extraction	11.69%		-0.07%	
311x, 312	Food Processing	11.62%		-0.21%	
327x	Nonmetallic Mineral	1.25%		-0.21%	
331	Primary Metal	1.99%		-0.34%	
334x	Semiconductor and Electronic ...	6.77%	42.30% (20351.06 GWh)	-0.58%	Decreasing (between -2.00% and -0.50%)
333	Machinery	2.49%		-0.59%	
315, 316	Apparel & Leather	0.53%		-0.63%	
1133, 321	Logging & Wood	1.19%		-0.64%	
3344	Computer Manufacturing	4.76%		-0.68%	
324	Petroleum	16.54%		-0.68%	
3221	Paper (excl. Mills)	1.35%		-0.71%	
336	Transportation Equipment	3.63%		-0.72%	
313	Textile Mills	0.35%		-0.78%	
322x	Pulp and Paper	1.53%		-0.79%	
323	Printing	1.32%		-1.06%	
337	Furniture	0.53%		-1.43%	
212	Other Mining	1.17%		-1.51%	
314	Textile	0.14%		-1.64%	

Source: California Energy Commission staff

Figure D-9 reflects statewide industrial electricity consumption trends over three discrete periods, and their related annual growth rates. The first period is the historical period from 1992 through 2012. During this period, the average statewide annual growth rate decreased by 0.41 percent, which was driven by energy efficiency gains, increasing energy prices, and economic conditions. The second period is the 2012 to 2024 forecast where the average statewide annual growth rate is expected to increase by about 0.04 percent due to more optimistic economic projections. The third period is the combined historical and forecast period of 1992 through 2024. During this period, the average statewide annual growth rate decreases by 0.24 percent per year.

Figure D-9: Statewide Industrial Electricity Consumption Trend (2012 Base Year)



Source: California Energy Commission staff

Conclusion

Although industries vary in electricity consumption behavior, the industrial sector as a whole is generally stable. This is largely driven by the stability of the few large industries that dominate the sector. In fact, the largest 4 industries consume nearly as much electricity as the remaining 24 industries combined.

Of the four largest industries, three are expected to experience a slight decrease in electricity consumption in the coming years, while one industry, chemical manufacturing, is expected to experience modest growth. Most of the remaining industries are not expected to experience excessive (greater than plus or minus 0.5 percent) annual growth or decline, and the few that are expected to experience greater change are a very small percentage of industrial sector electricity consumption overall.

Future work should consider an in-depth study of the largest four or five industries as they have the largest effect on California's industrial sector overall.