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California Energy Commission

COMMISSION FINAL REPORT

California Energy Demand 2018-2030 Revised Forecast

California Energy Commission

Edmund G. Brown Jr., Governor

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California Energy Commission

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ABSTRACT

The *California Energy Demand 2018 — 2030 Revised Forecast* describes the California Energy Commission's revised 12-year forecasts for electricity consumption, retail sales, and peak demand for each of five major electricity planning areas and for the state as a whole. This forecast supports the analysis and recommendations set forth in the *2017 Integrated Energy Policy Report.* The forecast includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid-energy demand* case. The *high energy demand* case incorporates relatively high economic/demographic growth and climate change impacts, and relatively low electricity rates and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases. This report also describes hourly load forecasts, which incorporate residential time-of-use pricing, electric vehicle charging profiles, and photovoltaic system generation profiles. Finally, this report describes the process for development, and presents estimates, of savings through additional achievable energy efficiency and photovoltaic adoptions.

Keywords: Electricity, demand, consumption, forecast, peak, self-generation, conservation, energy efficiency, climate zone, electrification, light-duty electric vehicles, distributed generation, natural gas, time-of-use pricing, hourly load forecasts.

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EXECUTIVE SUMMARY

Introduction

This California Energy Commission report presents forecasts of electricity and natural gas consumption and peak electricity demand for California and for each major utility planning area within the state for 2018 — 2030. The *California Energy Demand 2018 — 2030 Revised Forecast* (*CED 2017 Revised*) supports the analysis and recommendations of the *2017 Integrated Energy Policy Report*, including electricity system assessments and analysis of progress toward increased energy efficiency, with goals recently codified in Senate Bill 350 (SB 350, De León, Chapter 547, Statutes of 2015), and distributed generation.

The *Integrated Energy Policy Report (IEPR)* Lead Commissioner conducted a public workshop on December 15, 2017, to receive public comments on this forecast. However, a couple of elements to the forecast were still incomplete by the time of this workshop. This report incorporates these missing elements. Following comments on this draft report, staff will prepare a final report and forecast for possible adoption by the Energy Commission in February.

CED 2017 Revised includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid-energy demand* case. The *high energy demand* case is characterized by relatively high economic/demographic growth and climate change impacts, and relatively low electricity rates and self-generation impacts. Lower economic/demographic growth, higher assumed rates, and higher self-generation impacts are included in the *low energy demand* case. The *mid* case input assumptions are between the *high* and *low* cases. These forecasts are presented first as *baseline* cases, meaning they do not include additional achievable energy efficiency savings nor additional achievable photovoltaic (PV) adoptions. The baseline forecasts are then adjusted by these additional elements to provide managed forecasts for resource planning.

Results

The *CED 2017 Revised* baseline electricity forecast for selected years is compared with the California Energy Demand Updated Forecast 2017 — 2017 (*CEDU 2016*) mid demand case in **Table ES-1**. *CED 2017 Revised* adds a historical year for consumption (2016) and for peak demand (2017). Forecast consumption in the *CED 2017 Revised* mid demand case starts below the *CEDU 2016* mid case as additional utility efficiency program impacts are included for the 2016 and 2017 program years. Consumption in the new mid case rises above *CEDU 2016* by 2020 and remains higher thereafter. Faster growth in *CED 2017 Revised* mid baseline consumption relative to *CEDU 2016* is the result of four factors:

- Significantly higher projections for the number of light-duty electric vehicles (EVs)
- A higher forecast for manufacturing electricity consumption
- The decay in savings from the 2016 — 2017 efficiency programs
- A change in the manner in which residential lighting savings are accounted for in the forecast

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

Consumption (Gigawatt-hours (GWh))				
	CEDU 2016 Mid Energy Demand	*CED 2017 Revised* High Energy Demand	*CED 2017 Revised* Mid Energy Demand	*CED 2017 Revised* Low Energy Demand
1990	227,606	227,593	227,593	227,593
2000	261,036	260,941	260,941	260,941
2016	285,434	284,060	284,060	284,060
2020	294,474	299,836	295,773	292,519
2025	312,223	329,724	320,375	311,266
2027	319,256	339,863	328,215	317,491
2030	--	354,209	339,160	326,026
	Average Annual Growth Rates			
1990-2000	1.38%	1.38%	1.38%	1.38%
2000-2016	0.56%	0.53%	0.53%	0.53%
2016-2020	0.78%	1.36%	1.02%	0.74%
2016-2027	1.02%	1.64%	1.32%	1.02%
2016-2030	--	1.59%	1.27%	0.99%
Noncoincident Net Peak (Megawatts (MW))				
	CEDU 2016 Mid Energy Demand	*CED 2017 Revised* High Energy Demand	*CED 2017 Revised* Mid Energy Demand	*CED 2017 Revised* Low Energy Demand
1990	47,123	47,123	47,123	47,123
2000	53,529	53,530	53,530	53,530
2016	60,543	62,117	62,117	62,117
2017*	60,739	60,713	60,713	60,713
2020	61,444	62,970	61,295	59,730
2027	63,501	71,142	66,037	61,890
2030	--	73,844	67,704	63,118
	Average Annual Growth Rates			
1990-2000	1.28%	1.28%	1.28%	1.28%
2000-2016	0.77%	0.93%	0.93%	0.93%
2017-2020	0.39%	1.22%	0.32%	-0.54%

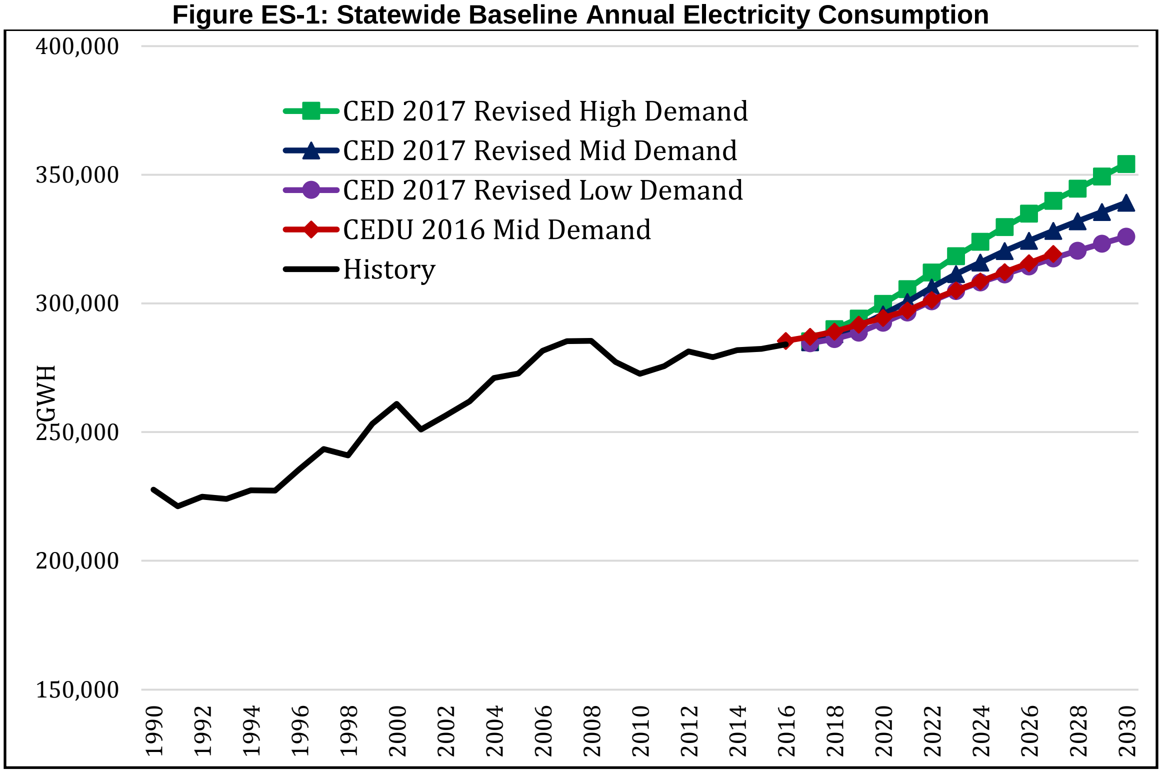
Consumption (Gigawatt-hours (GWh))				
2017-2027	0.45%	1.60%	0.84%	0.19%
2017-2030	--	1.52%	0.84%	0.30%
Actual historical values are shaded.				
*Weather normalized: the forecasts use a weather-normalized peak value derived from the actual 2017 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Energy Assessments Division, 2017.

CED 2017 Revised statewide noncoincident weather-normalized peak demand also grows at a faster rate in the mid case compared to *CEDU 2016*, a result of higher projected consumption and the impacts of incorporating the peak shift, which overcome the effect of a higher PV forecast. PV impacts in the low demand case are enough to drive average annual growth in peak demand negative from 2017 — 2020.

Projected electricity consumption for the three *CED 2017 Revised* baseline cases and the *CEDU 2016* mid demand forecast is shown in **Figure ES-1**. In 2027, consumption in the new mid case is projected to be almost 3 percent higher than the *CEDU 2016* mid case, which roughly matches the new low case. Annual growth from 2016 — 2027 for the *CED 2017 Revised* forecast averages 1.64 percent, 1.32 percent, and 1.02 percent in the high, mid, and low cases, respectively, compared to 1.02 percent in the *CEDU 2016* mid case.

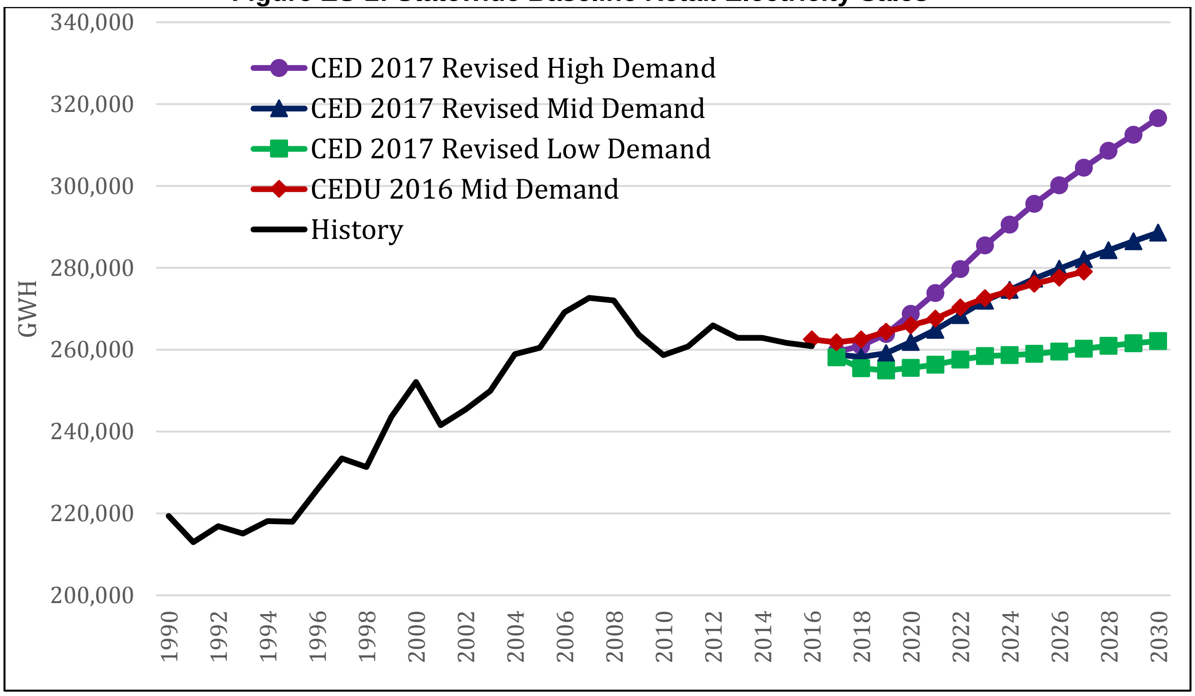
Figure ES-1: Statewide Baseline Annual Electricity Consumption



Source: California Energy Commission, Energy Assessments Division, 2017.

Projected statewide baseline electricity sales for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case are shown in **Figure ES-2.** The increase in projected consumption met with self-generation in *CED 2017 Revised* because more photovoltaic adoption, along with the 2016 — 2017 efficiency programs, reduces all three new forecast cases below the *CEDU 2016* mid case at the beginning of the forecast period. Growing light-duty EV consumption pushes the new high and mid cases above *CEDU 2016* by 2020 and 2024, respectively. By 2027, sales in the *CED 2017 Revised* mid case are projected to be around 1 percent higher than in the *CEDU 2016* mid case. Annual growth from 2016 — 2027 for *CED 2017 Revised* averages 1.41 percent, 0.71 percent, and -0.02 percent in the high, mid, and low cases, respectively, compared to 0.56 percent in the *CEDU 2016* mid case.

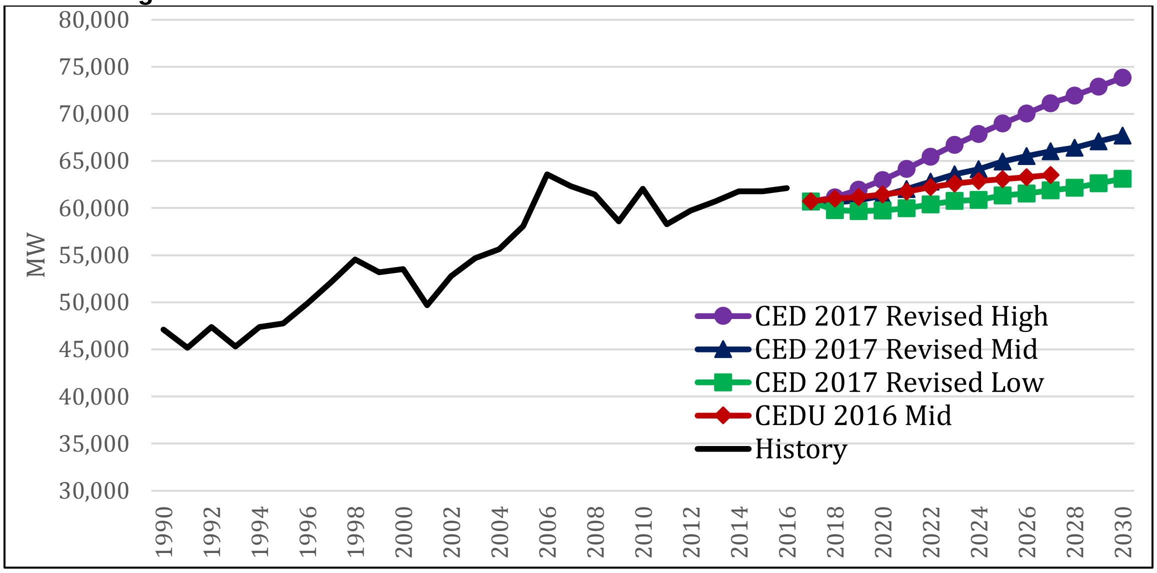
Figure ES-2: Statewide Baseline Retail Electricity Sales



Source: California Energy Commission, Energy Assessments Division, 2017.

Projected *CED 2017 Revised* noncoincident net peak demand for the three baseline cases, adjusted by the peak shift impact for the investor-owned utilities (IOUs), and the *CEDU 2016* mid demand peak forecast are shown in **Figure ES-3**. Because of the peak shift, net peak demand grows at a faster rate than sales in all three demand cases in the new forecast, and in the mid case pushes above *CEDU 2016* by an earlier year. By 2027, statewide peak demand in the *CED 2017 Revised* mid case is projected to be around 4 percent higher than the *CEDU 2016* mid case. Annual growth rates from 2017-2027 for *CED 2017 Revised* average 1.60 percent, 0.84 percent, and 0.19 percent in the high, mid, and low cases, respectively, compared to 0.45 percent in the *CEDU 2016* mid case. The higher projections for EVs have relatively less impact on peak demand than on consumption and sales, as most recharging occurs during off-peak hours.

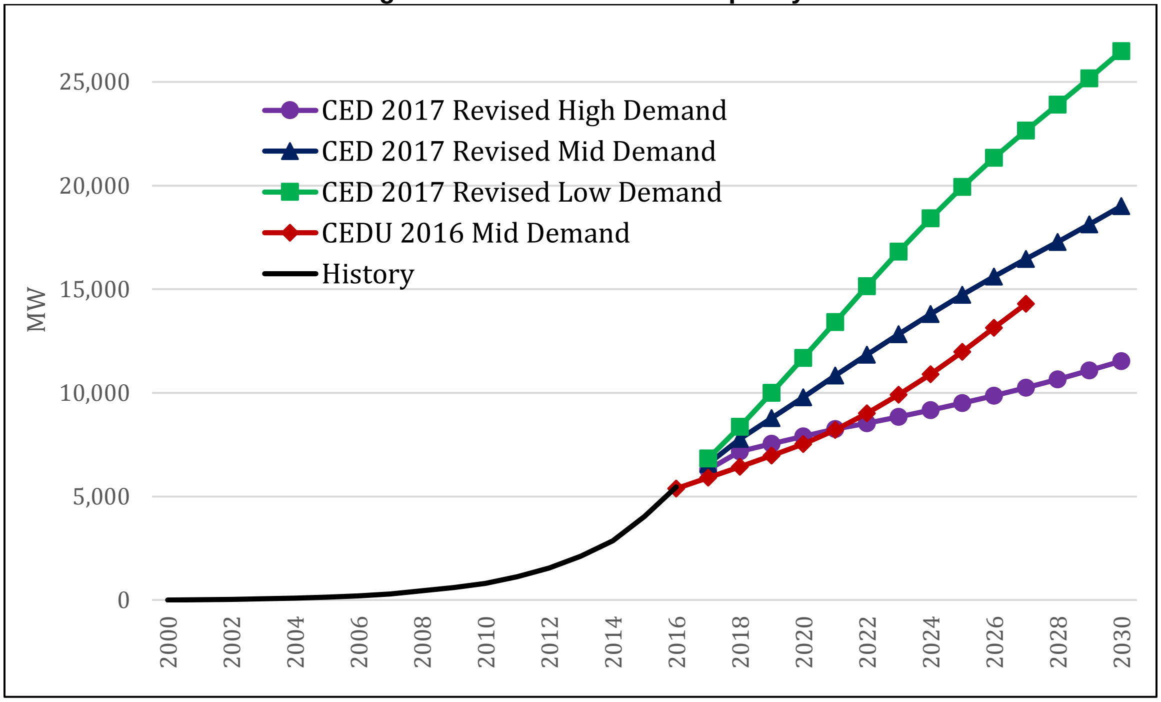
Figure ES-3: Statewide Baseline Annual Noncoincident Net Peak Demand



Source: California Energy Commission, Energy Assessments Division, 2017.

The key driver behind the peak shift phenomenon is increasing expected adoptions of PV systems. Historical and projected PV capacities for the three *CED 2017 Revised* demand cases and the *CEDU 2016* mid case are shown in **Figure ES-4**. Projected capacity reaches about 26,500 MW, 19,000 MW, and 11,500 MW in the low, mid, and high demand baseline cases, respectively, by 2030.

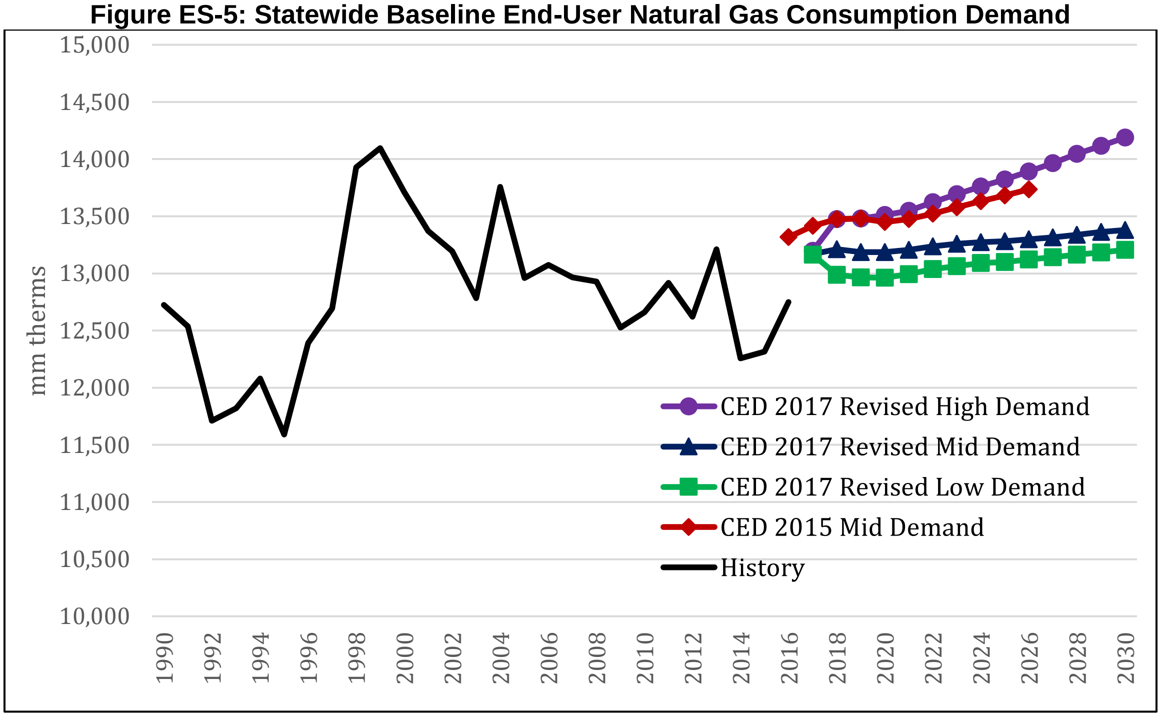
Figure ES-4: Statewide PV Capacity



Source: California Energy Commission, Energy Assessments Division, 2017.

Statewide natural gas consumption demand for the three *CED 2017 Revised* cases and the *CED 2015* mid case is also shown in **Figure ES-5**. The historical series clearly shows the variability in consumption from year to year, with changes in weather a key contributor to this variability. The figure shows a rather large jump from 2016 to 2017 in the new forecast, a result of the weather adjustment process in the residential and commercial models. The year 2016 was very warm in general, with a relatively small number of heating degree days over the year (reflects demand for energy to heat building). With heating accounting for almost 50 percent of natural gas demand in the residential and commercial sectors, consumption in 2016 was reduced significantly. From 2017 onward, weather is assumed historically "average" (aside from incremental climate change impacts) so that the number of heating degree days increases relative to 2016, accounting for this jump. **Figure ES-5** also shows a bump upward in the new high case and downward in the low case from 2017-2018, owing to significant projected industrial sector output growth/decline in this year in these two cases. In 2018 and beyond, growth in the *CED 2017 Revised* mid case is lower than in *CED 2015*, a result of implementation of the 2016 Title 24 building standards updates and a lower forecast for natural gas vehicles. Consumption in the low demand case increases relative to the new mid case over the forecast period as climate change impacts, which reduce consumption, do not affect the former.

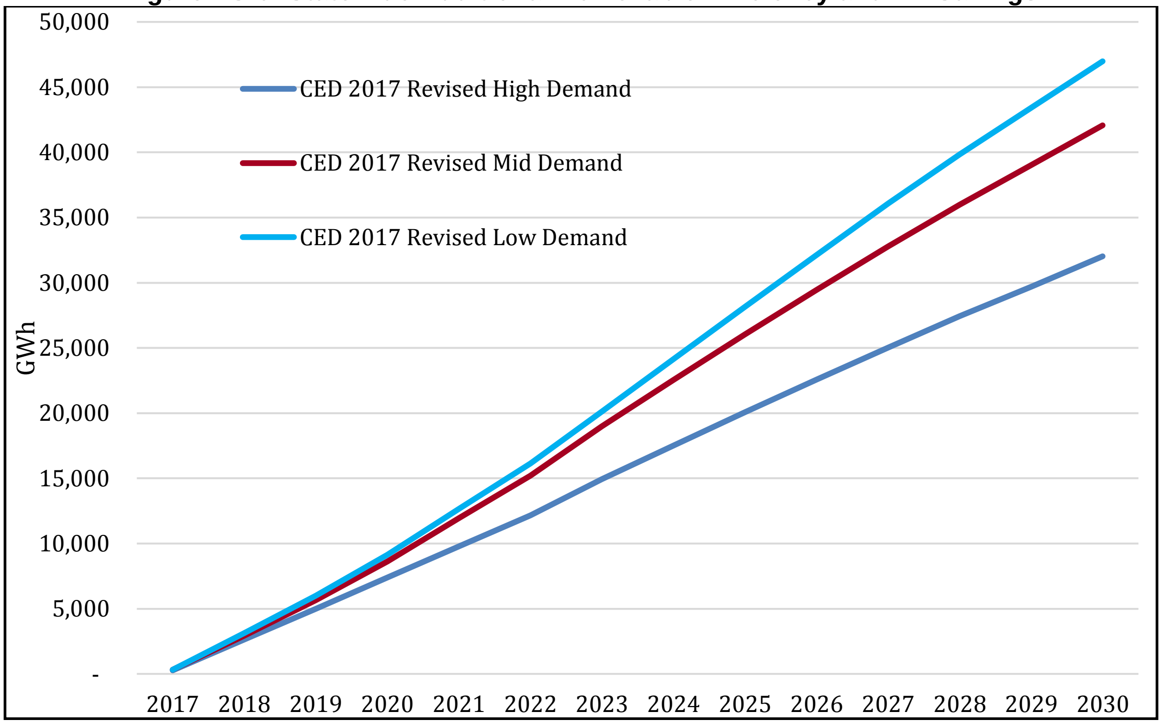
Figure ES-5: Statewide Baseline End-User Natural Gas Consumption Demand



Source: California Energy Commission, Energy Assessments Division, 2017.

Managed forecasts, which adjust for "traditional" additional achievable energy efficiency savings, additional efficiency savings estimated in support of SB 350, and additional achievable PV under various scenarios, are provided for all the planning areas for electricity and natural gas. **Figure ES-6** shows the total statewide adjustment from baseline to managed forecast for electricity sales for the three demand cases.

Figure ES-6: Statewide Additional Achievable Efficiency and PV Savings



Source: California Energy Commission, Energy Assessments Division, 2017.

Summary of Changes to Forecast

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

Utility efficiency program impacts in the baseline forecast, or "committed" savings, have been updated to reflect activity in 2016 and 2017. Expected program impacts beyond 2017 are incorporated in the managed forecasts through additional achievable (future, undefined) energy efficiency (AAEE) savings. The 2016 updates to Title 24 building standards are included in the *CED 2017 Revised* baseline, with future likely standards updates also handled through AAEE estimates. For the IOUs, most of estimated AAEE savings are derived from the CPUC's *2018 Potential and Goals Study*, while estimates for publicly owned utilities rely on individual utility adopted goals. Both IOU and publicly owned utility future savings are augmented by staff analysis for SB 350.

The Title 24 building standards updates expected in 2019 will include requirements for PV installations for new homes as a contributor toward the state's zero-net-energy goals. Since mandated efficiency improvements from the 2019 Title 24 are part of AAEE and not in the baseline forecast, consistent treatment of PV installations requires that the estimated additional installations from these 2019 updates be treated separately from PV adoptions in the baseline forecast, thus additional achievable photovoltaic (AAPV) adoption. In addition, the predictive model for PV adoptions now incorporates the impact of residential time-of-use (TOU) rates on PV system adoption.

CED 2017 Revised incorporates a new transportation electricity forecast, which includes light-duty vehicles, medium- and heavy-duty vehicles, public transit, and high-speed rail. Predicted light-duty EV purchases, which include battery electric and plug-in hybrid, were discussed and vetted through the Demand Analysis Working Group (DAWG), a technical stakeholder group, and the Joint Agency Steering Committee (JASC), comprised of energy agency management, and are significantly higher than in previous forecasts, reflecting current trends and more optimistic projections for these vehicles.

Energy Commission staff has developed an hourly load forecasting model for the IOU planning areas. This model incorporates hourly PV generation (including AAPV) and hourly load impacts of EVs, residential TOU pricing, and AAEE. The TOU component constitutes an additional new modeling effort for the Energy Commission. The hourly load model was used to develop estimated impacts from potential "peak shift" for each IOU, reflecting changes in utility peak hours and load brought on by demand modifier impacts.

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CHAPTER 1: Statewide Baseline Forecast Results and Forecast Method

Introduction

This California Energy Commission report presents forecasts of electricity and natural gas consumption and peak electricity demand for California and for each major utility planning area within the state for 2018 — 2030. The *California Energy Demand 2018 — 2030 Revised Forecast* (*CED 2017 Revised*) supports the analysis and recommendations of the *2017 Integrated Energy Policy Report*, including electricity system assessments and analysis of progress toward increased energy efficiency, with goals recently codified in Senate Bill 350 (SB 350, De León, Chapter 547, Statutes of 2015), and distributed generation.

The *Integrated Energy Policy Report (IEPR)* Lead Commissioner conducted a public workshop on December 15, 2017, to receive public comments on this forecast. However, a couple of elements to the forecast were still incomplete by the time of this workshop. This report incorporates these missing elements. Following comments on this draft report, staff will prepare a final report and forecast for possible adoption by the Energy Commission in February.

The revised/final forecasts will be used in several applications, including the California Public Utilities Commission (CPUC) resource planning.[1] 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."[2] The final forecasts will also be an input to the California Independent System Operator (California ISO) Transmission Planning Process as well as controlled grid studies and in electricity supply-demand (resource adequacy) assessments.

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

1 Energy Commission and CPUC staffs are working together to properly align the IEPR process with both the Integrated Resource (demand and supply planning to meet emissions targets) and Distributed Resource Planning (optimal locations for renewable distributed generation, energy efficiency, storage, electric vehicles, and storage on distribution system) proceedings.

2 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.

self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases. These forecasts as presented in this chapter are *baseline* cases meaning they do not include additional achievable energy efficiency (AAEE) savings or additional achievable photovoltaic (AAPV) adoptions. The baseline forecasts adjusted by these additional elements are provided in **Chapters 2** and **4**.

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

Summary of Changes to Forecast

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

CED 2017 Revised uses the modified geographic scheme for planning areas and climate zones introduced for *CED 2015*,[3] which is more closely based on California's balancing authority areas.[4] The modified scheme has been more fully integrated into the sector models for this forecast through the inputs, rather than relying on mapping of outputs as in previous forecasts. The results of the Energy Commission's ongoing Title 20 data regulations rulemaking will determine the additional consumption and metered data available from the utilities to support further geographic disaggregation of future forecasts. Once the data availability becomes clear, Energy Commission staff will work with the utilities to determine an optimal level of disaggregation to better serve transmission and distribution level analyses.

Utility efficiency program impacts in the baseline forecast, or "committed" savings, have been updated to reflect activity in 2016 and 2017. Expected program impacts beyond 2017 are incorporated in AAEE savings. The 2016 updates to Title 24 building standards are included in the *CED 2017 Revised* baseline, with future likely standards updates also handled through AAEE estimates. For the investor-owned utilities (IOUs), most of

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

4 *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.

estimated AAEE savings are derived from the CPUC's *2018 Potential and Goals Study*,[5] while estimates for publicly owned utilities rely on individual utility adopted goals. Both IOU and publicly owned utility future savings are augmented by staff analysis for SB 350. At the statewide level, estimated committed efficiency savings implemented in 2015 — 2017 plus estimated AAEE savings out to 2030 constitute the Energy Commission's initial estimates of progress toward meeting the SB 350 goals.[6]

The Title 24 building standards updates expected in 2019 will include requirements for PV installations for new residential homes as a contributor toward the state's zero net energy (ZNE) goals. Since mandated efficiency improvements from the 2019 Title 24 are part of AAEE and not in the baseline forecast, consistent treatment of PV installations requires that the estimated additional installations from these 2019 updates be treated separately from PV adoptions in the baseline forecast, thus AAPV. In addition, the predictive model for PV adoptions now incorporates the impact of residential time-of-use (TOU) rates on PV system adoption. **Appendix A** provides full details on the PV (and other self-generation) predictive model.

CED 2017 Revised incorporates a new transportation electricity forecast, which includes light-duty vehicles, medium- and heavy-duty vehicles, public transit, and high-speed rail. Predicted light-duty electric vehicle (EV) purchases, which include battery electric and plug-in hybrid, were vetted through the Demand Analysis Working Group (DAWG) and the Joint Agency Steering Committee (JASC) and are significantly higher than in previous forecasts, reflecting current trends and more optimistic projections for these vehicles.

Energy Commission staff has developed an hourly load forecasting model for the IOU planning areas. This model incorporates hourly PV generation (including AAPV) and hourly load impacts of electric vehicles, residential TOU pricing, and AAEE. The TOU component constitutes an additional new modeling effort for the Energy Commission. The hourly load model was used to develop estimated impacts from potential "peak shift" for each IOU, reflecting changes in utility peak hours and load brought on by demand modifier impacts. The hourly load model and peak shift are discussed in **Chapter 3**. As in the annual forecast, progress to develop this model for additional utilities and load pockets will depend on the outcome of the current Title 20 rulemaking.

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

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

Statewide Results

The *CED 2017 Revised* baseline electricity forecast for selected years is compared with the *CEDU 2016* mid demand case[7] in **Table 1**. *CED 2017 Revised* adds an historical year for consumption (2016) and for peak demand (2017). Forecast consumption in the *CED 2017 Revised* mid demand case starts below the *CEDU 2016* mid case as additional utility efficiency program impacts are included for the 2016 and 2017 program years. Consumption in the new mid case rises above *CEDU 2016* by 2020 and remains higher thereafter. Faster growth in *CED 2017 Revised* mid consumption relative to *CEDU 2016* is the result of four factors:

- Significantly higher projections for the number of light-duty EVs
- A higher forecast for manufacturing electricity consumption
- The decay in savings from the 2016 — 2017 efficiency programs
- A change in the manner in which residential lighting savings are accounted for in the forecast

Regarding the third factor, the baseline forecast does not assume measure replacement for committed programs (this is left for the AAEE portion), so there is a significant drop-off in savings from the
2016 — 2017 programs over the forecast period as measures (particularly lighting) reach the expected useful life. Regarding the fourth factor, past forecasts have assumed reductions in home lighting use consistent with Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007), which calls for 50 percent reductions in residential lighting by 2018 compared to 2007. By assuming that the AB 1109 requirements were met by 2018 and beyond, past baseline forecasts did not measure lighting savings from programs and standards directly.[8] However, given improvements in evaluation, measurement, and verification (EM&V) studies in recent years, staff decided that incorporating future programs and standards targeting lighting would provide a more accurate approach than simply assuming the requirements are met. Because the baseline forecast includes only committed efficiency, lighting savings from programs beyond 2017 that contribute to the AB 1109 goals are not included (are transferred to the AAEE portion), so average lighting use begins to increase in 2018 and later years, driving up growth in residential consumption.

7 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.

8 In previous forecasts, staff would “net out” the future lighting savings attributable to AB 1109 from estimated AAEE.

CED 2017 Revised statewide noncoincident[9] weather-normalized[10] peak demand also grows at a faster rate in the mid case compared to *CEDU 2016*, a result of higher projected consumption and the impacts of the IOU peak shift, which overcome the effect of a higher PV forecast. PV impacts in the low demand case are enough to drive average annual growth in peak demand negative from 2017 — 2020.

Projected electricity consumption for the three *CED 2017 Revised* baseline cases and the *CEDU 2016* mid demand forecast is shown in **Figure 1**. In 2027, consumption in the new mid case is projected to be almost 3 percent higher than the *CEDU 2016* mid case, which roughly matches the new low case. Annual growth from 2016 — 2027 for the *CED 2017 Revised* forecast averages 1.64 percent, 1.32 percent, and 1.02 percent in the high, mid, and low cases, respectively, compared to 1.02 percent in the *CEDU 2016* mid case.

9 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.

10 Peak demand is weather-normalized in 2017 to provide the proper benchmark for comparison to future peak demand, which assumes either average (normalized) weather or hotter conditions measured relative to 2017 due to climate change.

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	CEDU 2016 Mid Energy Demand	*CED 2017 Revised* High Energy Demand	*CED 2017 Revised* Mid Energy Demand	*CED 2017 Revised* Low Energy Demand
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2000-2016	0.56%	0.53%	0.53%	0.53%
2016-2020	0.78%	1.36%	1.02%	0.74%
2016-2027	1.02%	1.64%	1.32%	1.02%
2016-2030	--	1.59%	1.27%	0.99%
Noncoincident Net Peak (MW)				
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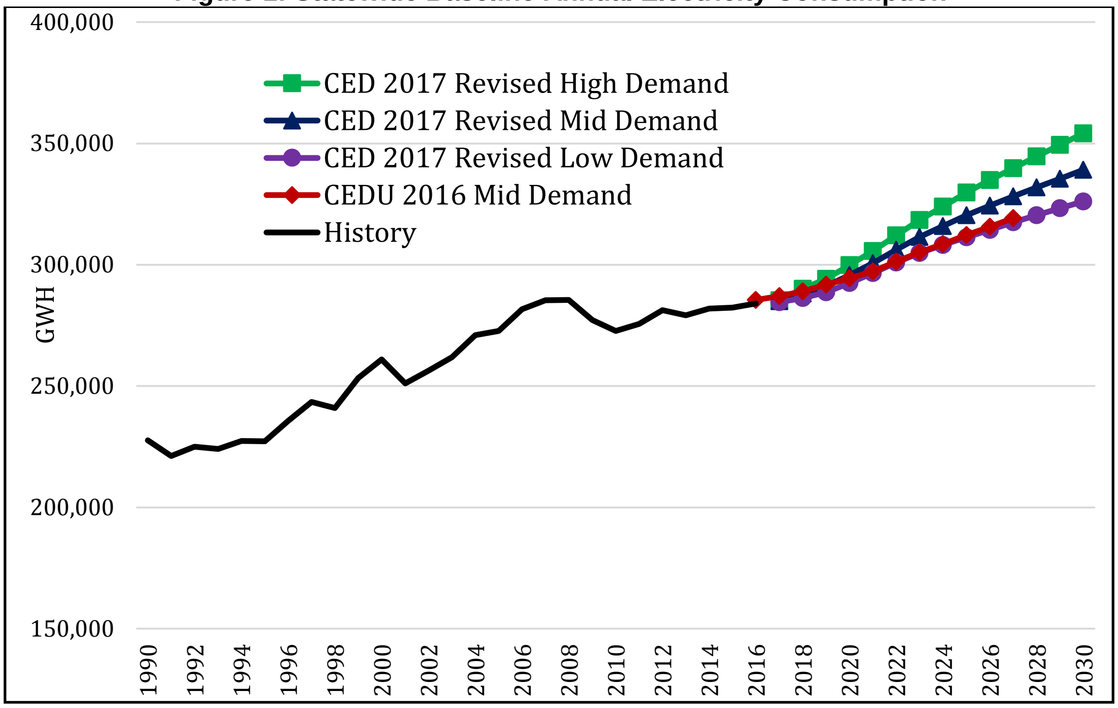
2030	--	73,844	67,704	63,118
	Average Annual Growth Rates			
1990-2000	1.28%	1.28%	1.28%	1.28%
2000-2016	0.77%	0.93%	0.93%	0.93%
2017-2020	0.39%	1.22%	0.32%	-0.54%
2017-2027	0.45%	1.60%	0.84%	0.19%
2017-2030	--	1.52%	0.84%	0.30%
Actual historical values are shaded.				
*Weather normalized: the forecasts use a weather-normalized peak value derived from the actual 2017 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 1: Statewide Baseline Annual Electricity Consumption

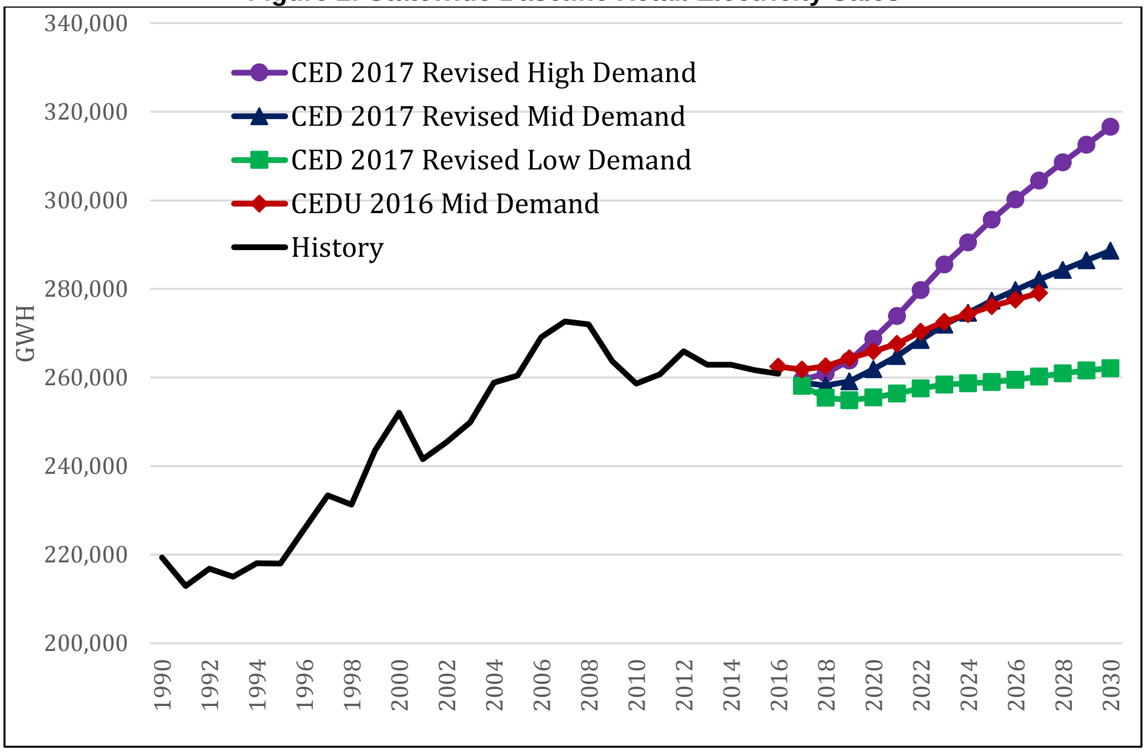


Source: California Energy Commission, Energy Assessments Division, 2017.

Projected statewide baseline sales for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case are shown in **Figure 2**. The increase in projected consumption met with self-generation in *CED 2017 Revised* because more PV adoption, along with the 2016-2017 efficiency programs, reduces all three new forecast cases below the *CEDU 2016* mid case at the beginning of the forecast period. Growing light-duty EV consumption pushes the new high and mid cases above *CEDU 2016* by 2020 and 2024, respectively. By 2027, sales in the *CED 2017 Revised* mid case are projected to be around 1 percent higher than in the *CEDU 2016* mid case. Annual growth from 2016–2027 for *CED 2017 Revised* averages 1.41 percent, 0.71 percent, and -0.02 percent in the high, mid, and low cases, respectively, compared to 0.56 percent in the *CEDU 2016* mid case.

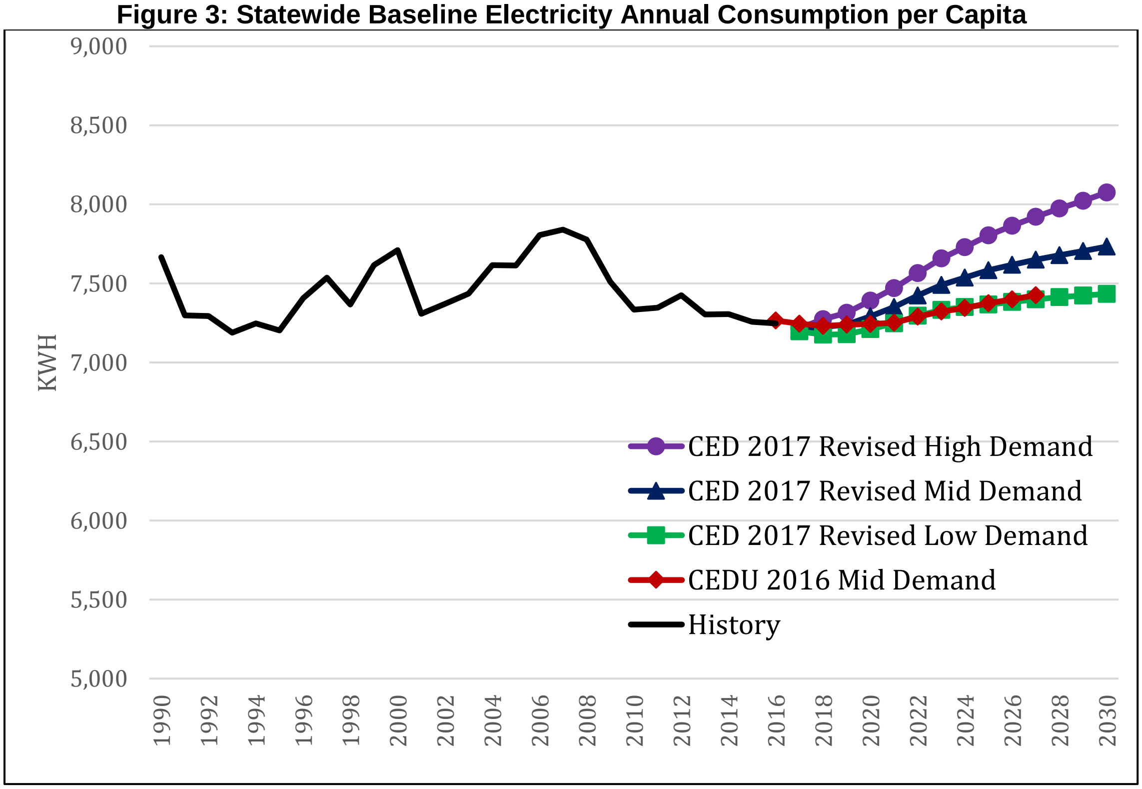
As shown in **Figure 3**, *CED 2017 Revised* baseline per-capita electricity consumption is projected to be relatively flat through 2019 in the low and mid cases (as in *CEDU 2016* mid) because consumption is projected to grow at about the same rate as population. Thereafter, per-capita consumption rises due to increasing EV use. Higher economic/demographic growth in the high demand case combined with EVs increases per-capita consumption from 2017 on. More total electricity consumption in the new mid case pushes per-capita consumption above the *CEDU 2016* mid case by 2020.

Figure 2: Statewide Baseline Retail Electricity Sales



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 3: Statewide Baseline Electricity Annual Consumption per Capita



Source: California Energy Commission, Energy Assessments Division, 2017.

Projected baseline annual electricity consumption in each *CED 2017 Revised* case for the three major economic sectors—residential, commercial, and industrial (manufacturing, construction, and resource extraction)—is compared with the *CEDU 2016* mid demand case in **Table 2**. As in past recent forecasts, residential consumption is projected to grow fastest among the sectors, a result of steady growth in the miscellaneous sector, which includes "plug-in" appliances such as cell phones and other electronics, and bolstered by EVs. Commercial consumption growth is also boosted by the higher EV forecast, but to a lesser degree than in the residential sector, so the difference in percentage annual growth between the residential and commercial sectors in *CED 2017 Revised* increases over the forecast period. Forecast industrial consumption growth is flatter than in the other two sectors, a product of recent historical trends in consumption combined with industrial output projections.

Residential consumption in the new mid case grows at a faster rate from 2016 — 2027 compared to *CEDU 2016* because of a higher EV forecast and the change in the way that lighting savings are handled in the new forecast. Projected commercial consumption also grows at a faster rate in *CED 2017 Revised* mid compared to *CEDU 2016* primarily because of the increase in projected EV consumption. Despite additional efficiency programs targeting the industrial sector, industrial consumption grows at a faster pace in the new mid case compared to *CEDU 2016* due to higher projected growth in manufacturing output.

Projected *CED 2017 Revised* noncoincident net peak demand for the three baseline cases, adjusted by the peak shift impact for IOUs, and the *CEDU 2016* mid demand peak forecast are shown in **Figure 4**. Because of the peak shift, net peak demand grows at a faster rate than sales in all three demand cases in the new forecast, and in the mid case pushes above *CEDU 2016* by an earlier year. By 2027, statewide peak demand in the *CED 2017 Revised* mid case is projected to be around 4 percent higher than the *CEDU 2016* mid case. Annual growth rates from 2017 — 2027 for *CED 2017 Revised* average 1.60 percent, 0.84 percent, and 0.19 percent in the high, mid, and low cases, respectively, compared to 0.45 percent in the *CEDU 2016* mid case. The higher projections for EVs have relatively less impact on peak demand than on consumption and sales, as most recharging occurs in off-peak hours.[11]

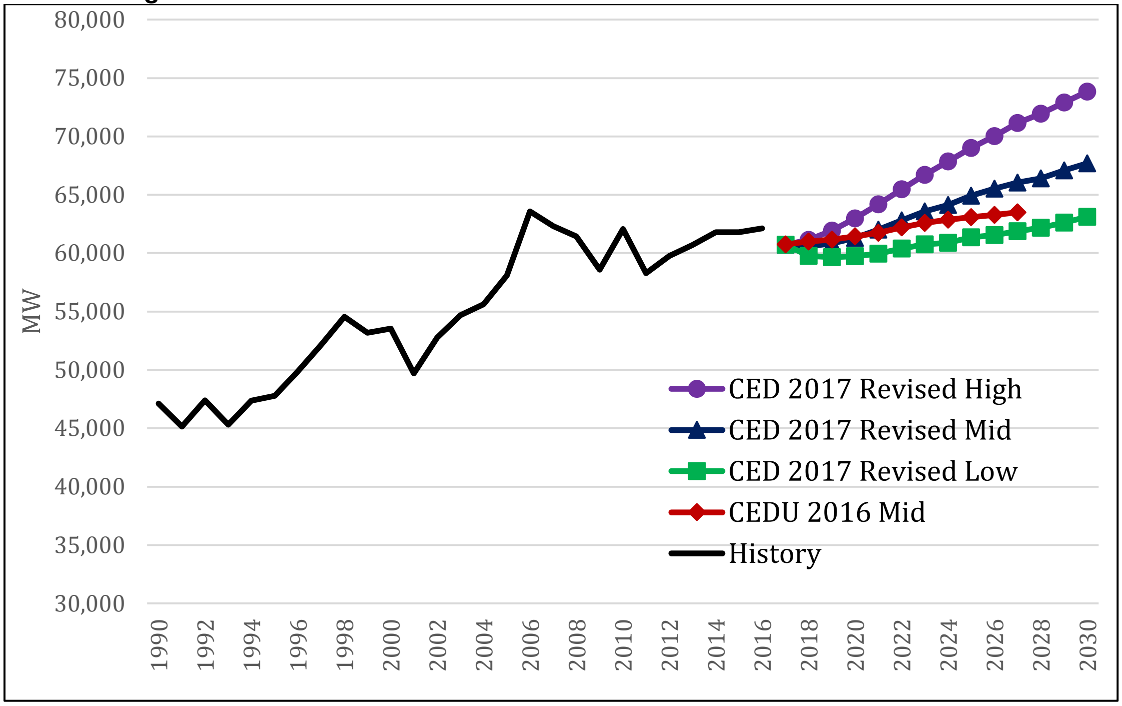
11 See **Chapter 3** for discussion of EV hourly charging impacts.

Table 2: Baseline Electricity Consumption by Sector

Residential Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Revised* High Energy Demand	*CED 2017 Revised* Mid Energy Demand	*CED 2017 Revised* Low Energy Demand
2016	89,394	90,886	90,886	90,886
2020	92,985	98,343	96,998	96,517
2025	103,383	113,237	109,333	107,143
2027	107,993	118,754	113,640	111,236
2030	--	127,461	120,409	117,647
Average Annual Growth, Residential Sector				
2016-2020	0.99%	1.99%	1.64%	1.51%
2016-2027	1.73%	2.46%	2.05%	1.85%
2016-2030	--	2.45%	2.03%	1.86%
Commercial Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Revised* High Energy Demand	*CED 2017 Revised* Mid Energy Demand	*CED 2017 Revised* Low Energy Demand
2016	108,531	104,986	104,986	104,986
2020	112,718	111,261	110,286	109,252
2025	118,473	122,439	120,167	116,775
2027	120,272	125,739	122,904	118,714
2030	--	129,665	126,077	120,661
Average Annual Growth, Commercial Sector				
2016-2020	0.95%	1.46%	1.24%	1.00%
2016-2027	0.94%	1.65%	1.44%	1.12%
2016-2030	--	1.52%	1.32%	1.00%
Industrial Consumption (GWh)				
	CEDU 2016 Mid Energy Demand	*CED 2017 Revised* High Energy Demand	*CED 2017 Revised* Mid Energy Demand	*CED 2017 Revised* Low Energy Demand
2016	49,612	50,308	50,308	50,308
2020	49,725	51,474	50,143	48,647
2025	49,902	53,763	51,444	48,432
2027	50,009	54,434	51,760	48,249
2030	--	55,233	52,050	47,798
Average Annual Growth, Industrial Sector				
2016-2020	0.06%	0.57%	-0.08%	-0.84%
2016-2027	0.07%	0.72%	0.26%	-0.38%
2016-2030	--	0.67%	0.24%	-0.36%
Actual historical values are shaded.				

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 4: Statewide Baseline Annual Noncoincident Net Peak Demand



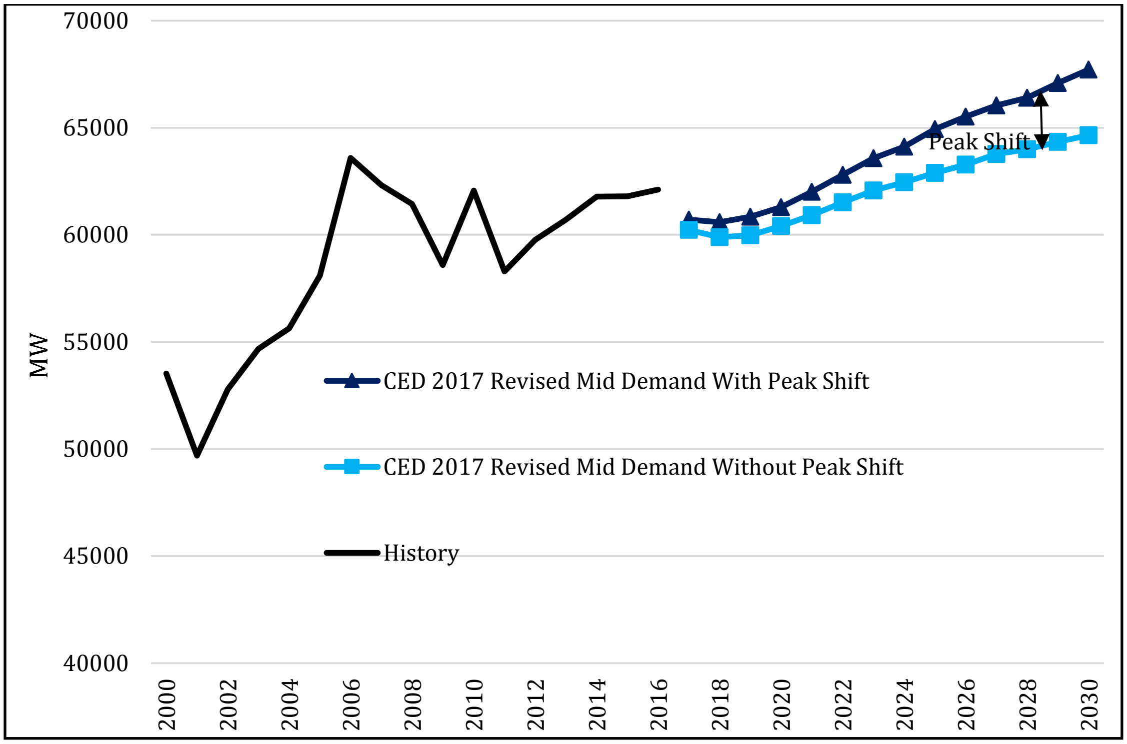
Source: California Energy Commission, Energy Assessments Division, 2017.

The impact of the peak shift for the IOU planning areas on statewide noncoincident net peak demand for the *CED 2017 Revised* mid case is shown in **Figure 5.** By 2030, the peak shift impact reaches more than 3,000 MW and increases the average annual growth rate for net peak from 0.65 percent to 1.00 percent over 2017 — 2030. Peak shift impacts in the high and low demand cases reach 1,000 MW and 6,100 MW, respectively, by 2030.[12] **Chapter 4** provides details on the peak shift for the IOU planning areas.

Statewide baseline noncoincident net peak demand per capita for the three *CED 2017 Revised* cases and the *CEDU 2016* mid case is shown in **Figure 6.** Increasing peak demand met by self-generation leads to declining demand per capita in the new mid and low cases (as well as *CEDU 2016* mid) at the beginning of the forecast period. While *CEDU 2016* continues to decline through 2027, the IOU peak shifts begin to increase per-capita demand in the new mid case by 2020. For the same reason, *CED 2017 Revised* low net peak demand starts to increase in 2029. By 2027, net peak demand in the new mid case is around 4.4 percent higher than *CEDU 2016*.

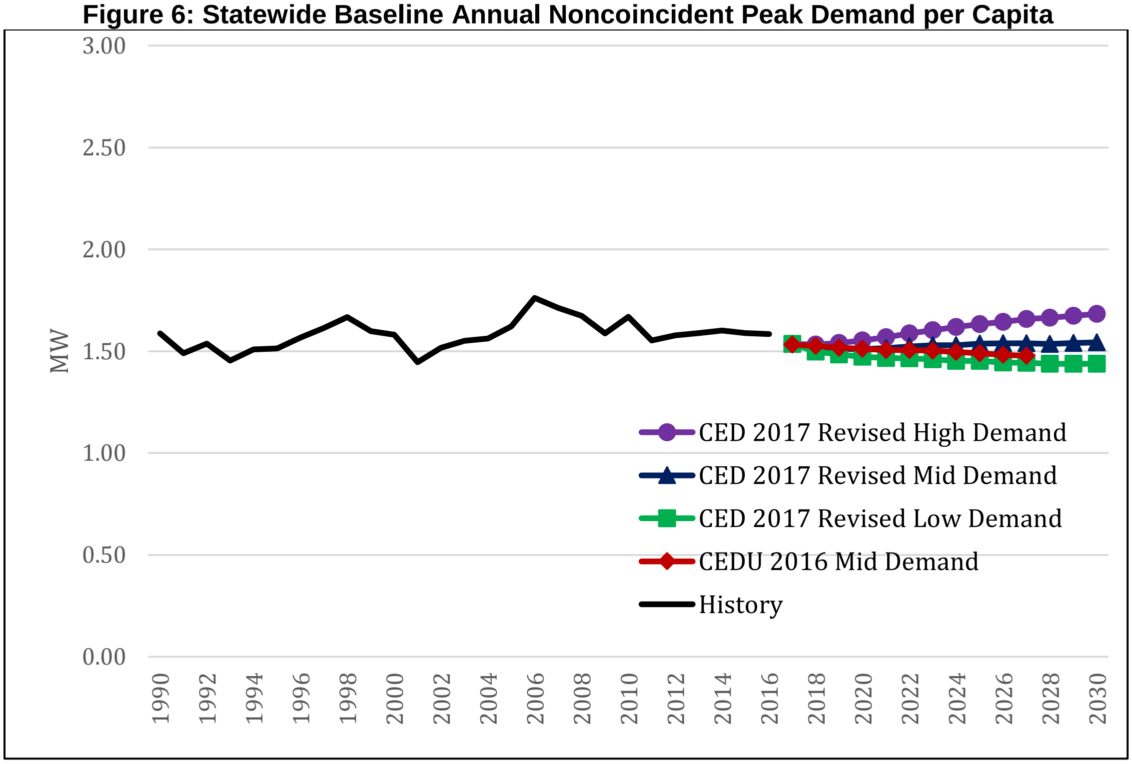
12 The low demand case includes much more PV and, therefore, has a more significant peak shift.

Figure 5: Peak Shift Impact on Statewide Noncoincident Net Peak, *CED 2017 Revised* Mid Case



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 6: Statewide Baseline Annual Noncoincident Peak Demand per Capita



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 3 shows statewide baseline end-user natural gas consumption demand for the three *CED 2017 Revised* cases and the mid case from *CED 2015* (a natural gas end-use forecast was not done for *CEDU 2016*). The natural gas forecast was developed using the same models as the electricity forecast, with similar adjustments for utility efficiency programs and building and appliance standards.

As 2016 was a very warm year in California, the *CED 2015* mid case forecast for 2016 (which assumes average weather) significantly overshoots actual consumption as demand for heating declined. Overall, growth in end-user natural gas consumption is flatter than for electricity consumption since the natural gas miscellaneous end use is not a significant growth factor, unlike electricity. By the end of the forecast period, low case consumption almost reaches the new mid case, a result of climate change impacts that affect (reduce) the mid case totals but not the low.

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

Natural Gas Consumption (mm therms)				
	CED 2015 Mid Energy Demand	*CED 2017 Revised* High Energy Demand	*CED 2017 Revised* Mid Energy Demand	*CED 2017 Revised* Low Energy Demand
1990	12,892	12,724	12,724	12,724
2000	13,913	13,713	13,713	13,713
2016	13,318	12,751	12,751	12,751
2020	13,450	13,512	13,186	12,964
2026	13,736	13,891	13,299	13,122
2030	--	14,190	13,378	13,207
	Average Annual Growth Rates			
1990-2000	0.77%	0.75%	0.75%	0.75%
2000-2016	-0.27%	-0.45%	-0.45%	-0.45%
2016-2020	0.25%	1.46%	0.84%	0.41%
2016-2026	0.31%	0.86%	0.42%	0.29%
2016-2030	--	0.77%	0.34%	0.25%
Actual historical values are shaded.				

Source: California Energy Commission, Energy Assessments Division, 2017.

The natural gas consumption forecast includes projected consumption by natural gas vehicles, provided by the Transportation Energy Forecast Unit (TEFU) of the Demand

Analysis Office.[13] Natural gas vehicles are estimated to have consumed around 255 (million) mm therms in 2015, rising to 630 mm therms, 330 mm therms, and 275 mm therms by 2030 in the high, mid, and low demand cases, respectively. TEFU did not provide a breakout by planning area; consumption was distributed to the planning areas based on total natural gas consumption (minus natural gas vehicles).

Statewide natural gas consumption demand for the three *CED 2017 Revised* cases and the *CED 2015* mid case is also shown in **Figure 7**. The historical series clearly shows the variability in consumption from year to year, with changes in weather a key contributor to this variability. The **figure 7** shows a rather large jump from 2016 to 2017 in the new forecast, a result of the weather adjustment in the residential and commercial models. The year 2016 was very warm in general, with a relatively small number of heating degree days[14] over the year. With heating accounting for almost 50 percent of natural gas demand in the residential and commercial sectors, consumption in 2016 was reduced significantly. From 2017 onward, weather is assumed historically "average" (aside from incremental climate change impacts) so that the number of heating degree days increases relative to 2016, accounting for this jump.[15] **Figure 7** also shows a bump upward in the new high case and downward in the low case from 2017 — 2018, owing to significant projected industrial sector output growth/decline in this year in these two cases.[16] In 2018 and beyond, growth in the *CED 2017 Revised* mid case is lower than in *CED 2015*, a result of implementation of the 2016 Title 24 building standards updates and a lower forecast for natural gas vehicle. Consumption in the low demand case increases relative to the new mid case over the forecast period as climate change impacts, which reduce consumption, do not affect the former.

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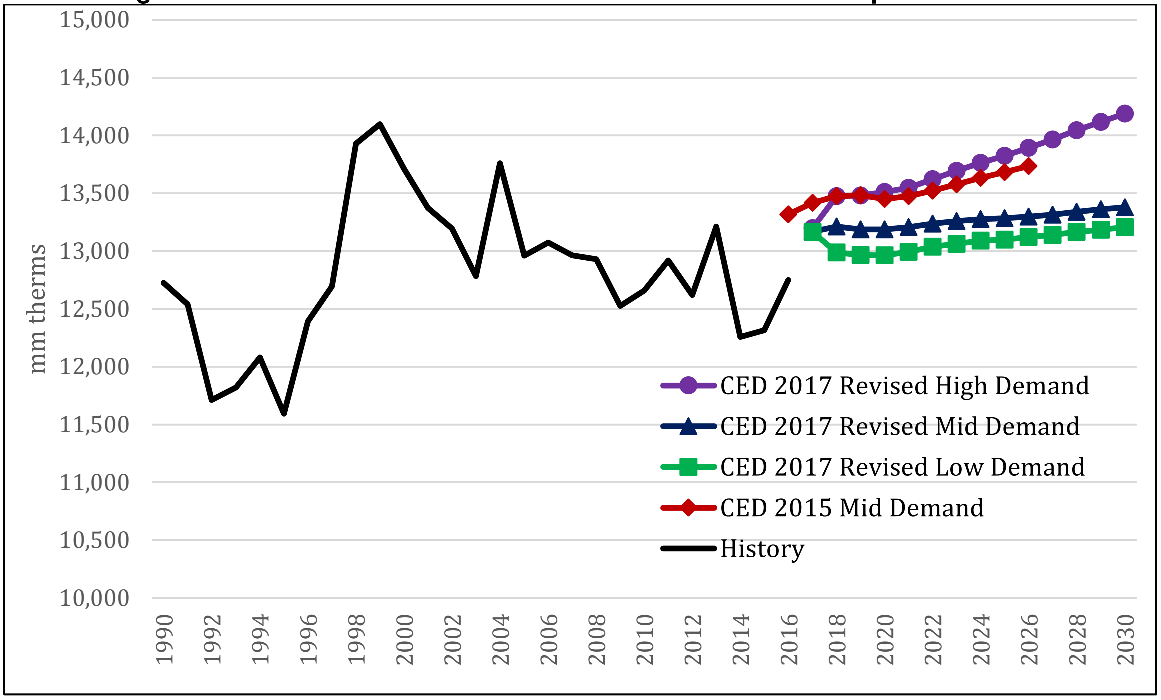
13 Details on the transportation forecasts are available in a transportation report here: http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-05/TN221893_20171204T085928_Transportation_Energy_Demand_Forecast_20182030.pdf.

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

15 The impact of heating degree days is measured through a regression model for residential and commercial consumption. The resulting coefficient for heating degree days is used to adjust consumption.

16 This is particularly the case with the oil and gas extraction sector, a significant user of natural gas.

Figure 7: Statewide Baseline End-User Natural Gas Consumption Demand



Source: California Energy Commission, Energy Assessments Division, 2017.

Method

Although the methods to estimate energy efficiency impacts and self-generation have undergone refinement, the *CED 2017 Revised* baseline forecast uses the same technical methods as previous long-term staff demand forecasts: detailed sector models supplemented with single equation econometric models, now applied to a revised geographic scheme. A full description of the sector models is available in a staff report.[17]

Geography

Staff energy demand forecasts are developed for eight electricity planning areas and four natural gas planning areas, with the electricity planning areas revised as of *CED 2015*. **Table 4** shows the load-serving entities included in each planning area. The Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and Valley Electric Association (VEA) electricity planning areas correspond to the four transmission access charge (TAC) areas[18] within the California ISO balancing authority area. The Northern California-non California ISO (NCNC) planning area is composed of two balancing authority areas: Turlock Irrigation District and the Balancing Authority of Northern California (BANC), which includes the Sacramento Municipal Utility District (SMUD). The Los Angeles Department of Water and Power (LADWP) and

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

18 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.

Burbank-Glendale (BUGL) planning areas together comprise the LADWP balancing authority area, and the Imperial Irrigation District (IID) is both a planning area and a balancing authority area. The smallest planning areas, VEA for electricity and Other for natural gas, are not incorporated within the demand forecast models but are postprocessed, with energy demand growth projected based on an average of the other planning areas. **Figure 8** provides a map of the electricity planning areas.

Some of the electricity planning areas are further divided into forecast zones. PG&E contains six zones, SCE five, NCNC three, and LADWP two, shown in **Figure 9**. **Chapter 4** summarizes forecast zone projections for the planning areas with multiple zones and results are provided with the demand forms accompanying this report. [19]

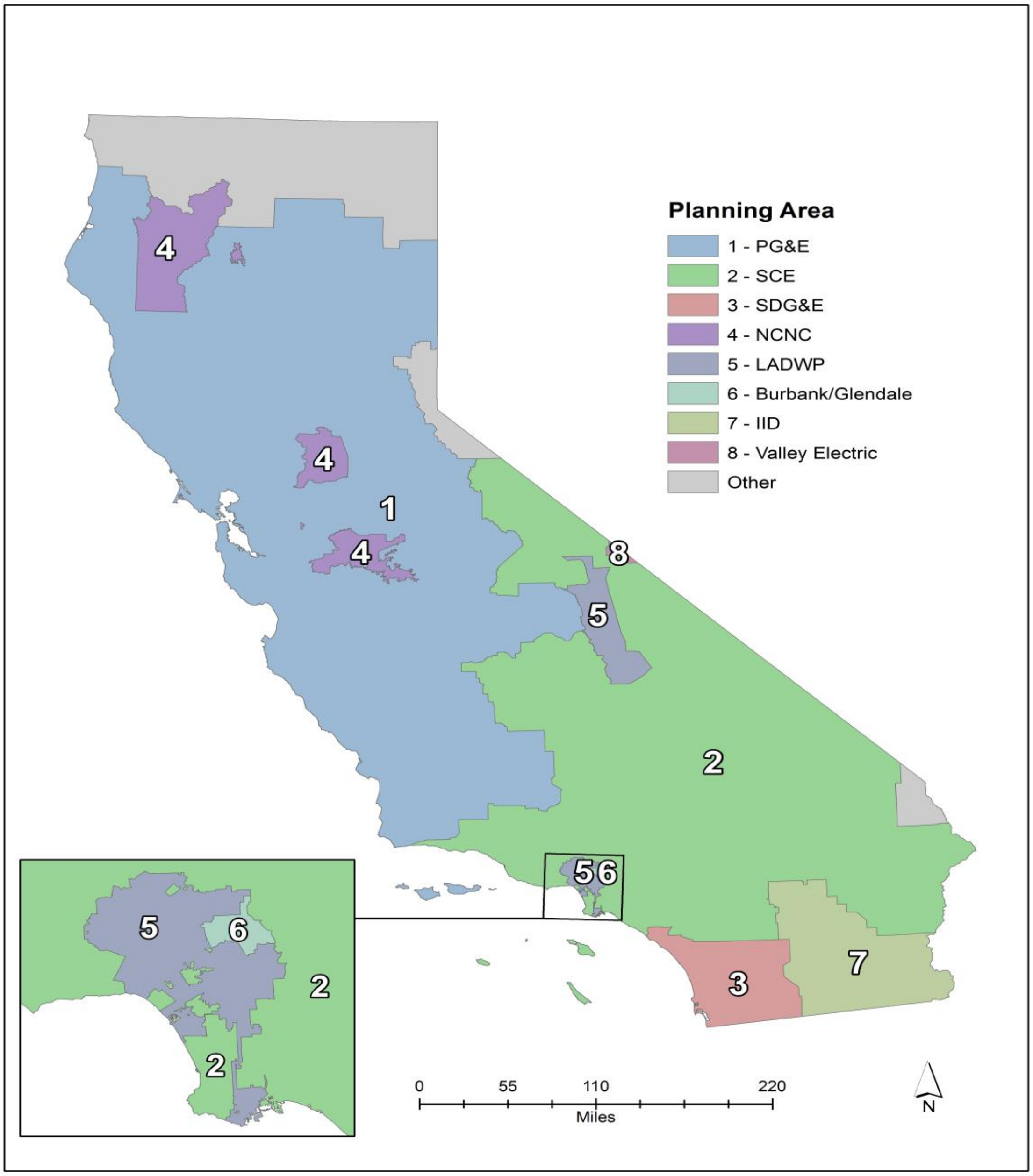
19 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

Table 4: Load-Serving Entities Within Forecasting Planning Areas

Electricity		
Planning Area	Utilities Included	
Pacific Gas and Electric (PG&E)	PG&E Alameda Biggs Calaveras California DWR (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)
Southern California Edison (SCE)	Anaheim Anza Azusa Banning Bear Valley Colton Corona California DWR (South) Metropolitan Water District	Moreno Valley Pasadena Rancho Cucamonga Riverside SCE Parker Davis Vernon Victorville
San Diego Gas & Electric (SDG&E)	SDG&E	
Northern California Non-California ISO (NCNC)	Merced Modesto Redding Roseville SMUD	Shasta Turlock Irrigation District Central Valley Project (BANC Operations)
Los Angeles Department of Water And Power (LADWP)	LADWP	
Burbank and Glendale (BUGL)	Burbank	Glendale
Imperial Irrigation District (IID)	IID	
Valley Electric Association (VEA)	VEA	
Natural Gas		
Planning Area	Utilities Included	
PG&E	PG&E	Palo Alto
Southern California Gas Company (SoCalGas)	SoCalGas Mojave Pipeline	Long Beach Northwest Pipeline
SDG&E	SDG&E	
Other	Southwest Gas Corporation	Avista Energy

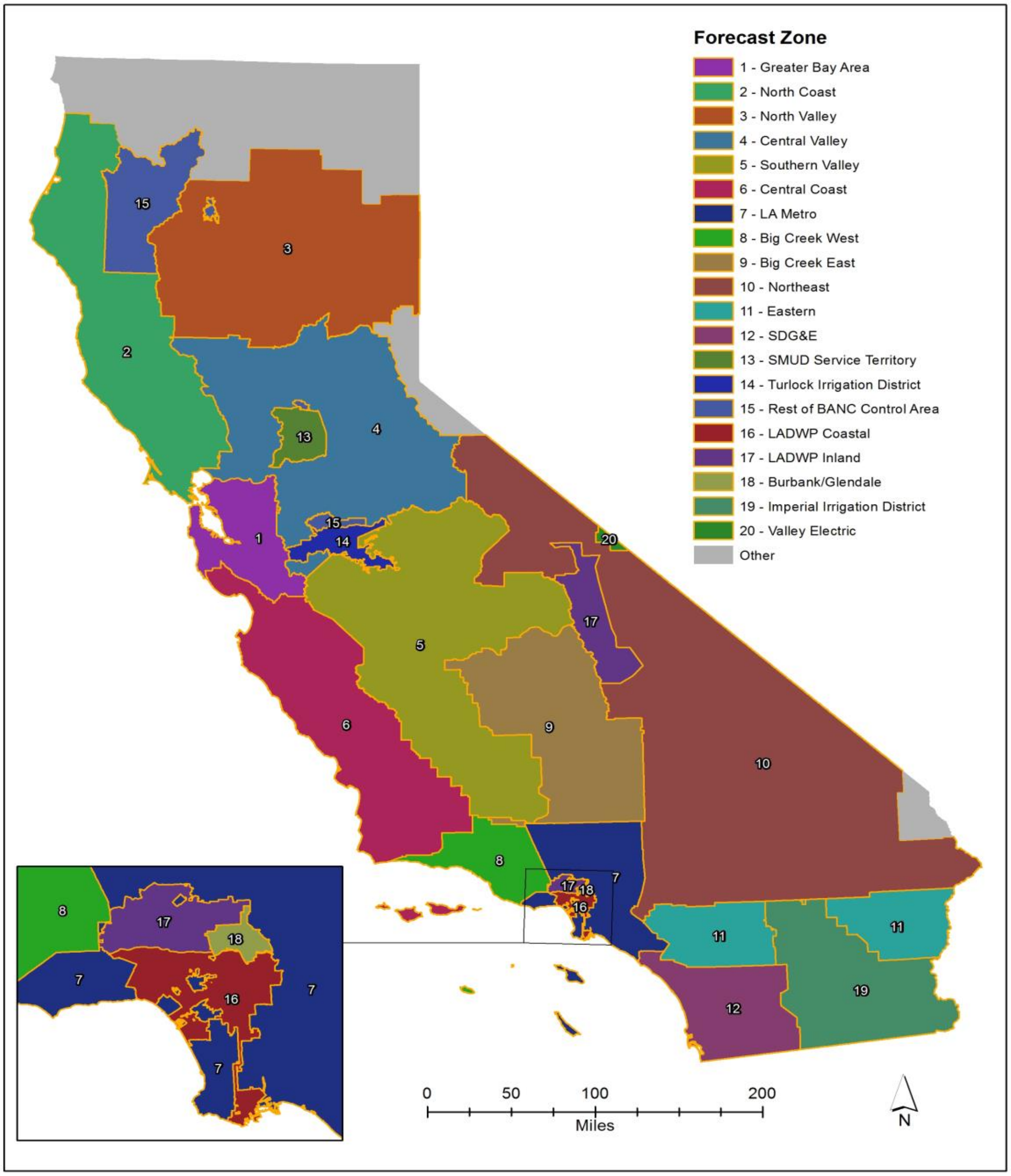
Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 8: Electricity Forecast Planning Areas



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 9: Electricity Forecast Zones



Source: California Energy Commission, Energy Assessments Division, 2017.

Economic and Demographic Inputs

Projections for statewide economic and demographic growth are summarized here. More detail, at the statewide level as well as for each planning area, is provided in the demand forms accompanying this report.[20] As in previous forecasts, staff relied on

20 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

Moody's Analytics (Moody's) and IHS Global Insight (Global Insight) to develop the economic growth scenarios to drive the three *CED 2017 Revised* demand cases. Demographic inputs relied on these two sources, as well as the latest forecasts from the California Department of Finance (DOF).

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

For population, staff used only one scenario, the DOF forecast, since Moody's, Global Insight, and DOF projected very similar growth.[21] The DOF projections for several households were used in the mid and low demand cases, with Moody's used for the high case. The key assumptions used by Moody's to develop the three economic scenarios applied in this forecast are provided in **Table 5.**

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

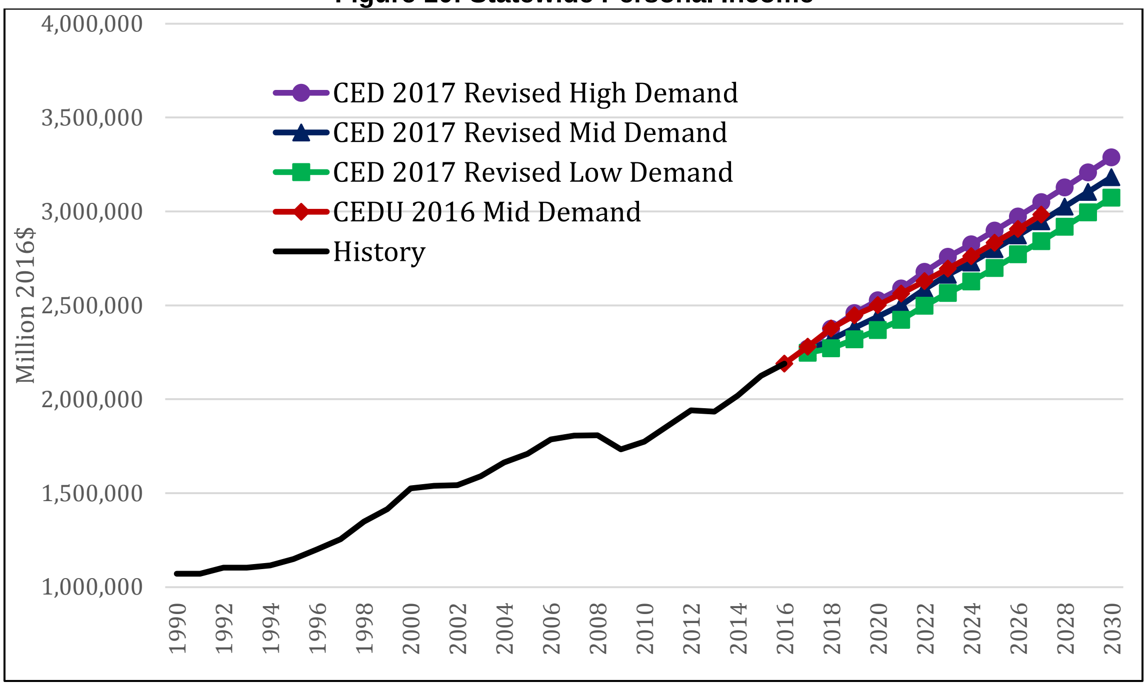
Table 5: Key Assumptions Embodied in *CED 2017 Revised* Economic Scenarios

High Demand Case (Moody's Custom High Growth Scenario), January 2017	***Mid Demand Case (Moody's Baseline Scenario), January 2017***	***Low Demand Case (Moody's Below-Trend Long-Term Growth Scenario), January 2017***
National unemployment rate will be fall to and remain 3.7 percent through 2018.	National unemployment rate stays below 4.5 percent through 2018.	National unemployment rate will be slightly more less than 5 percent through 2018.
The Federal Reserve responds to the hotter labor market, higher wages, and the potential for higher inflation by raising interest rates in the fourth quarter of 2017. Structural reforms and less restrictive fiscal polies support European growth.	The Federal Reserve is expected to steadily normalize interest rates over the next three years. The dollar should continue appreciating.	The high value of the dollar limits exports, as does the slower than expected Eurozone recovery.
National light-duty vehicle sales increase to 17.8 million in 2018	National light-duty vehicle sales hit 16.8 million in 2018.	National light-duty vehicle sales decline to 16.4 million in 2018.
National housing starts reach nearly 1.8 million units by 2018.	National housing starts are expected to be 1.6 million units by 2018.	National housing starts reach 1.4 million units by 2018.
Excess oil supply is reduced, and demand begins to outstrip supply, putting upward pressure on oil prices.	Oil prices will remain volatile but rise slowly.	Structural oversupply conditions in oil markets keep oil prices low—around $50 per barrel in the short term.
Though the economy grows above its potential, the government's fiscal situation continues to weaken but less than under the other two scenarios. Stronger economic growth slows but does not stop the deterioration in the deficit.	The Trump administration pushes forward its fiscal policy agenda. Moody's assumes there will be tax cuts costing around $1 trillion over the next decade.	Economic policies of the new presidential administration increase uncertainty among businesses and households alike, which slows growth and worsens the government's fiscal situation.

Source: Moody's Analytics, 2017.

Historical and projected personal income at the statewide level for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case is shown in **Figure 10**.[22] The new mid case is slightly lower than the *CEDU 2016* mid case at the end of the forecast period (around 1.2 percent in 2027), although the difference is greater from 2018 — 2022. Annual growth rates from 2016 — 2027 average 3.05 percent, 2.73 percent, and 2.40 percent in the *CED 2017 Revised* high, mid, and low cases, respectively, compared to 2.85 percent in the *CEDU 2016* mid case.

Figure 10: Statewide Personal Income

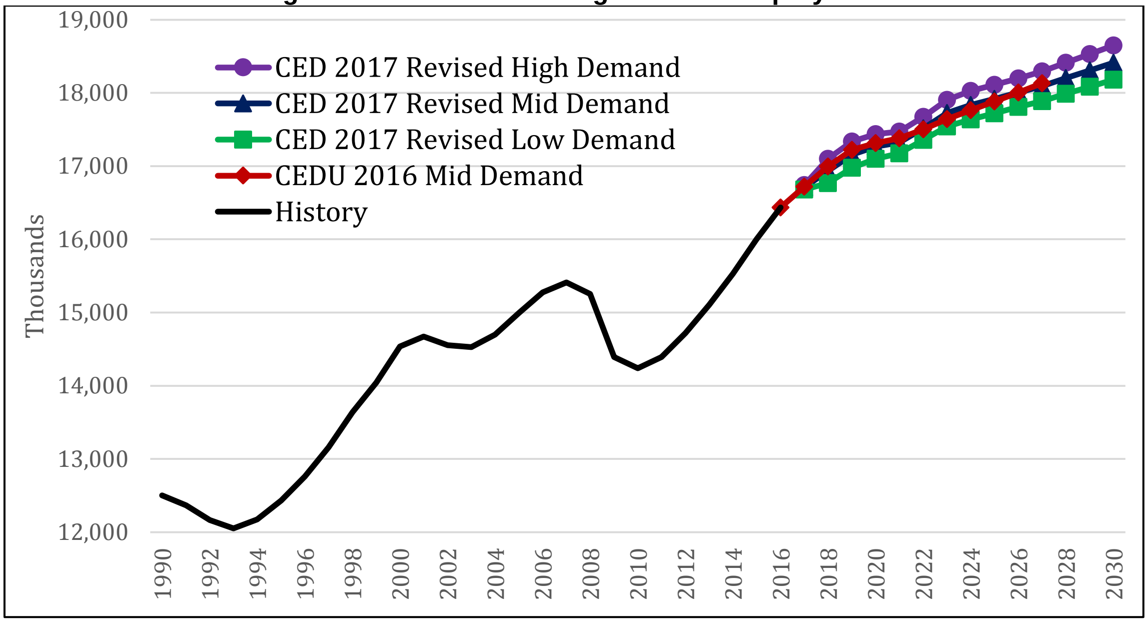


Source: Moody's Analytics, 2016-2017.

Historical and projected statewide nonagricultural employment for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case is shown in **Figure 11**. The *CED 2017 Revised* mid case is almost identical to *CEDU 2016* throughout the forecast period, with the difference between the new and old mid cases around 0.2 percent in 2027. Annual growth rates from 2016 — 2027 average 0.98 percent, 0.88 percent, and 0.70 percent in the *CED 2017 Revised* high, mid, and low cases, respectively, compared to 0.90 percent in the *CEDU 2016* mid case.

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

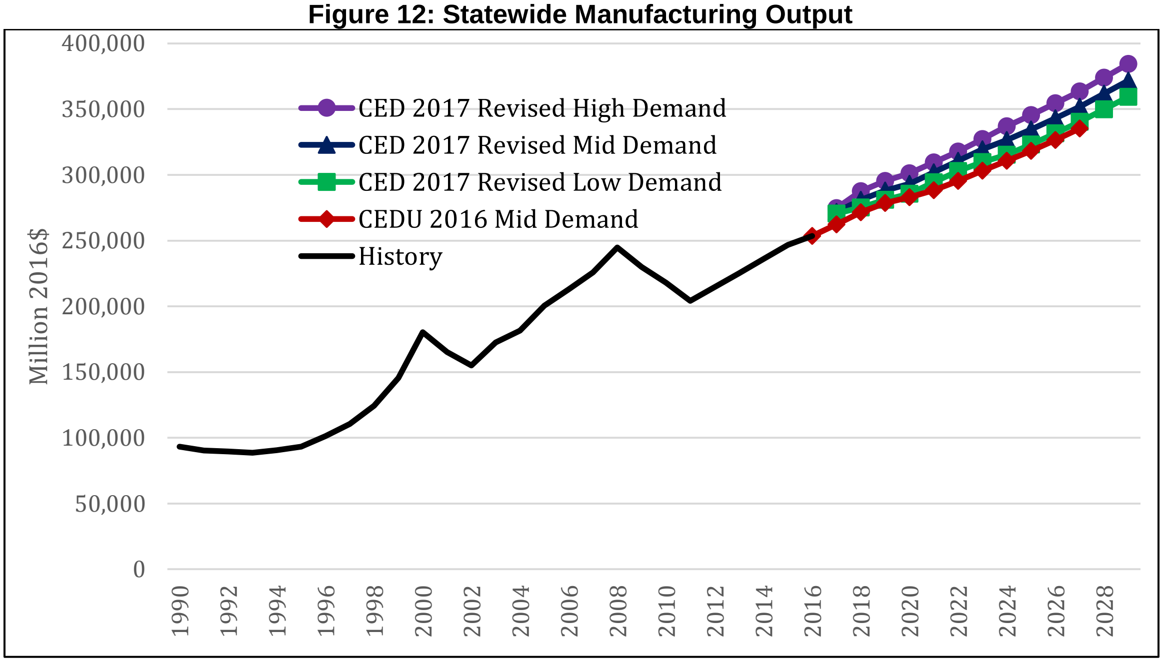
Figure 11: Statewide Nonagricultural Employment



Source: Moody's Analytics, 2016 — 2017.

Statewide manufacturing output for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case is shown in **Figure 12**. The *CED 2017 Revised* mid case is above *CEDU 2016*, which is closer to (and slightly below) the new low case. Annual growth rates from 2016 — 2027 average 3.32 percent, 3.02 percent, and 2.71 percent in the *CED 2017 Revised* high, mid, and low cases, respectively, compared to 2.57 percent in the *CEDU 2016* mid case.

Figure 12: Statewide Manufacturing Output

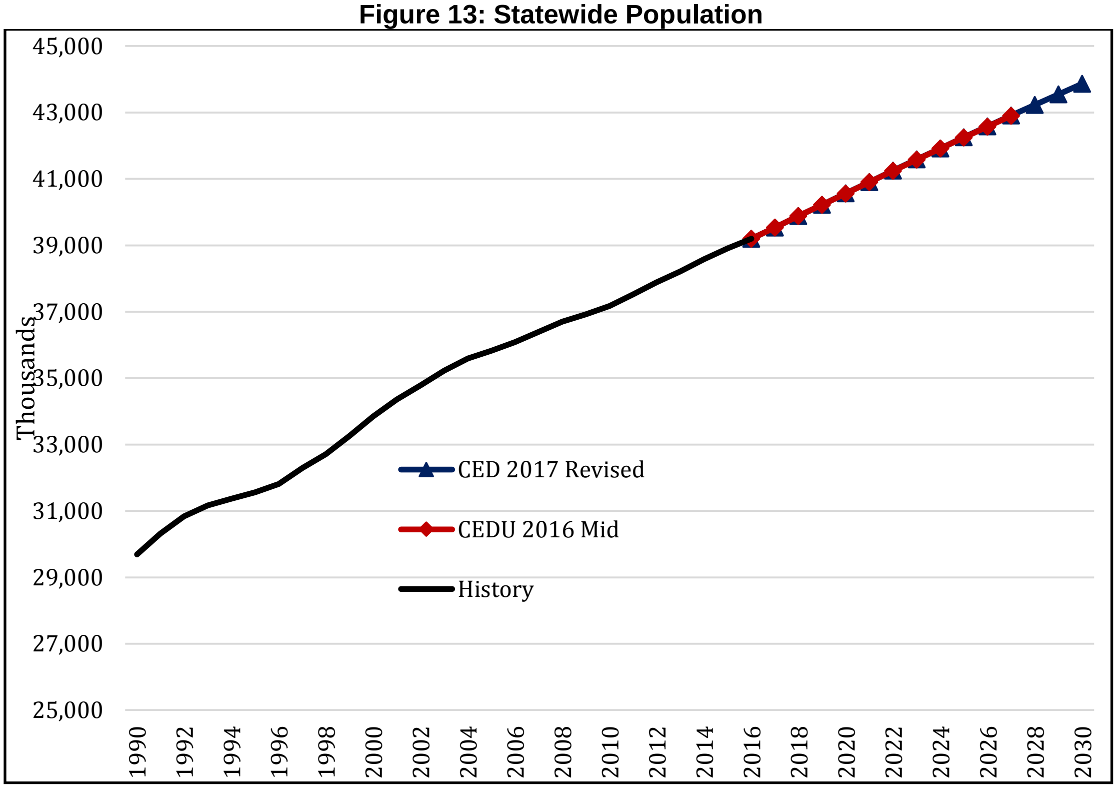


Source: Moody's Analytics, 2016 — 2017.

Projections for population are shown in **Figure 13**. The single *CED 2017 Revised* scenario projects almost identical growth compared to the *CEDU 2016* mid case throughout the forecast period. In 2027, the difference amounts to around 8,000 persons. Over the period 2016 — 2027, population growth averages around 0.82 percent for both *CED 2017 Revised* and the *CEDU 2016* mid case.

With the exception of the industrial sector, where higher manufacturing output pushes the new mid and high forecasts above *CEDU 2016* mid, the economic/demographic drivers overall do not significantly change the *CED 2017 Revised* mid case compared to *CEDU 2016*. Rather, the key demand modifiers, including PV and EVs, as well as the accounting for residential lighting savings, have a more important role in forecast differences.

Figure 13: Statewide Population



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

Electricity and Natural Gas Rates

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

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 costs for hydroelectric, nuclear, coal, other long-term contracts, debt service, customer service costs, transmission 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 *2017 IEPR*. Distribution revenue requirement scenarios were constructed using the utility-submitted data as input. The mid-case is consistent with utility projections, while growth in distribution revenue requirements is about 0.5 percent higher in the low demand case, and 0.5 percent lower in the high demand case.

New procurement needed to meet Renewables Portfolio Standard goals is valued based on the levelized costs of new wind and solar generation from the Supply Analysis Office cost of generation model. To value the additional non-renewable energy needed to serve load, staff developed a wholesale price forecast using projected natural gas hub prices, projected California carbon allowance prices, and staff production cost model results. The production cost analysis assumed 50 percent renewables procurement by California load-serving entities by 2030, which leads to declining implied market heat rates; therefore, wholesale electricity prices are projected to be lower than in previous forecasts.[23]

The method used to develop projected carbon allowance prices is based on the California Air Resources Board (CARB) *Regulations for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms*, approved by the Office of Administrative Law on September 18, 2017.[24] The high demand allowance price is at the floor price set by CARB, the low demand allowance price is at the reserve price, and the mid-case price is halfway in between.

A full listing of historical and projected rates by planning area is available in the demand forms accompanying this report.[25] The effect of increasing rates on the forecast is determined by model price elasticities of demand,[26] which average about 10 percent across the sectors.

Natural gas price scenarios were developed by the Energy Commission's Supply Analysis Office using the North American Gas-Trade Model (NAMGas). This model incorporates supply and demand components to generate equilibrium gas prices for California and subregions. The natural gas price scenarios were designed to be consistent with the

23 The heat rate describes how efficiently a given generation unit can convert fuel to electricity. Lower overall heat rates reduce variable costs of generation and therefore wholesale electricity prices.

24 https://www.arb.ca.gov/cc/capandtrade/capandtrade/unofficial_ct_100217.pdf .

25 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

26 *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.

demand cases as well as the electricity rate scenarios, which use natural gas prices as an input. The assumptions behind the natural gas scenarios were presented at an *IEPR* workshop on April 25, 2017.[27]

Price scenarios for the three major gas planning areas for selected years for the three major sectors by demand case are provided in **Chapter 4**. A full listing of historical and projected rates by planning area is available in the demand forms accompanying this report.[28] Similar to electricity, price elasticities average about 10 percent across the sectors.

Self-Generation

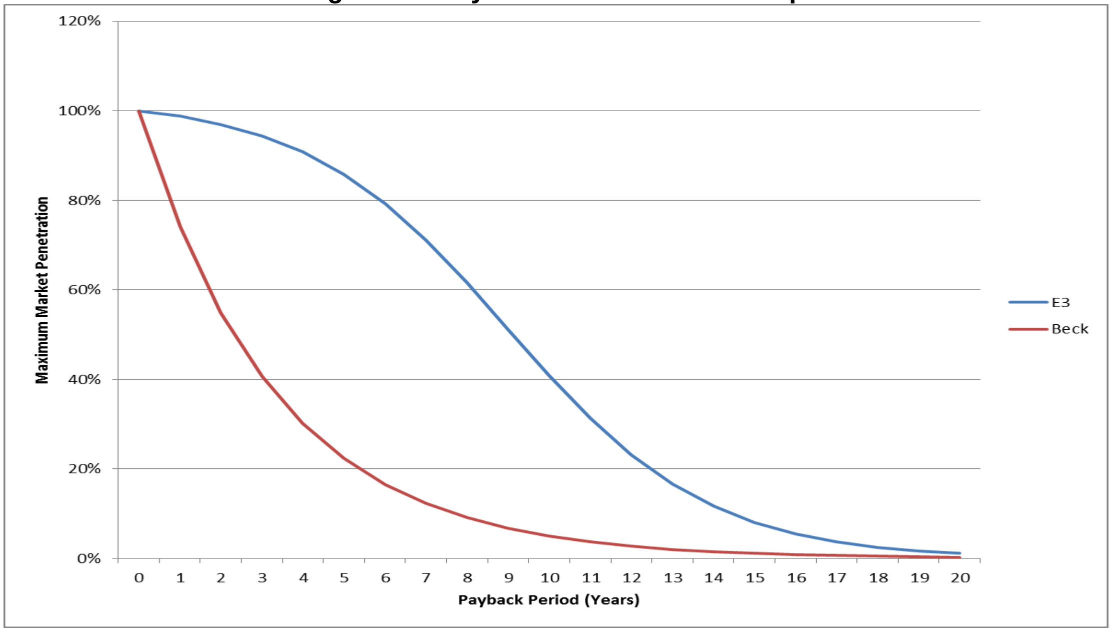
As in previous forecasts, *CED 2017 Revised* attempts to account for all major self-generation technologies, including PV, different forms of combined heat and power (CHP), wind turbines, electric fuel cells, solar water heating, and behind-the-meter storage, as well as the programs designed to promote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

Residential and commercial PV, residential solar water heating, and commercial CHP adoption are projected using predictive models, typically based on estimated payback periods and cost-effectiveness, determined by upfront costs, energy rates, and incentive levels. For *CED 2017 Revised*, staff modified the residential PV model for the three IOU planning areas and SMUD in the low demand case (meaning higher PV) so that adoptions are based on monthly bill savings rather than payback periods. This change results in a significant increase in projected adoption of PV systems, providing a wide variation between this case and the high demand (low PV) case. For the other planning areas, staff did not have sufficient residential hourly load data to base adoptions on monthly bill savings, and therefore specified PV adoption in the low demand case as a function of payback, using a payback curve (a curve relating payback time to market penetration) developed by the consulting firm E3 for the CPUC. Adoptions for all planning areas in the high demand case are based on a more pessimistic payback curve, developed by R.W. Beck. The two payback curves are shown in **Figure 14**. The mid case PV assumes a simple average of PV system additions in the high and low demand cases.

27 Materials available at http://www.energy.ca.gov/2017_energypolicy/documents/#10092017.

28 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

Figure 14: Payback Curves for PV Adoption



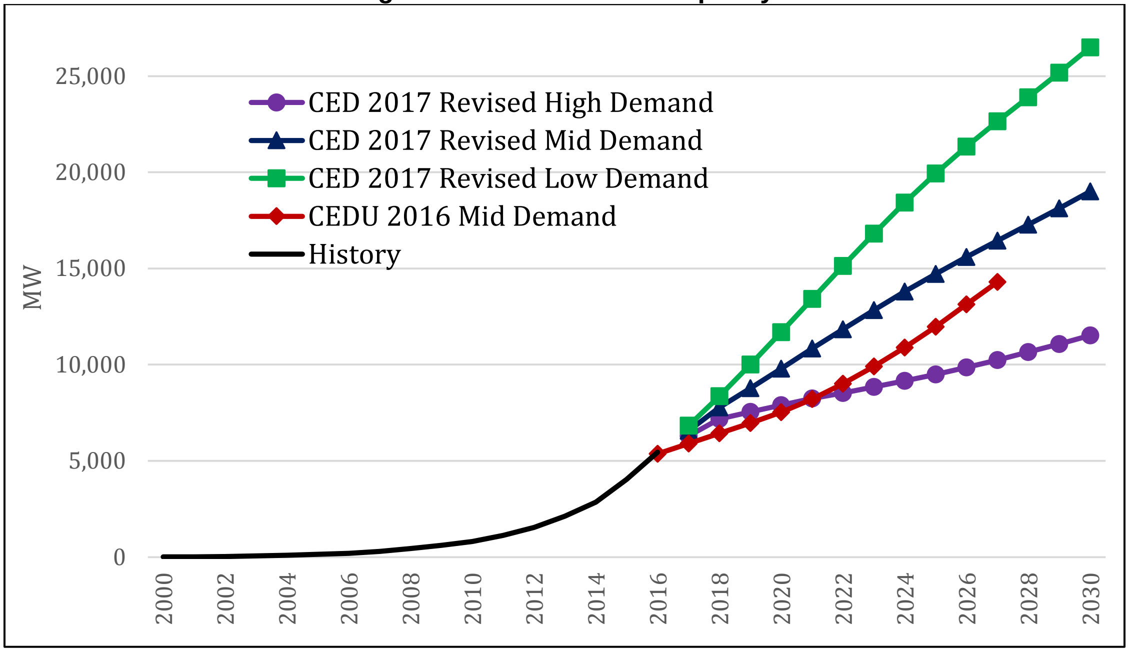
Source: California Energy Commission, Energy Assessments Division, 2017.

In addition, staff incorporated residential TOU programs for PV prediction starting in 2019, so that monthly bill savings for the IOUs and SMUD and therefore adoptions in the low demand case are based on modified residential load patterns. To account for uncertainty around CPUC net energy metering (NEM) policy after 2018, staff assumed full retail compensation for excess generation in the low demand case and 10 cents per kWh plus a fixed capacity charge in the high demand case. **Appendix A** provides more detail on staff's predictive methods and assumptions, as well as a discussion of NEM and other relevant issues.

Historical and projected PV capacity for the three *CED 2017 Revised* demand cases and the *CEDU 2016* mid case are shown in **Figure 15.** The change in residential modeling method for the three IOU planning areas and SMUD yields a projected capacity in the *CED 2017 Revised* low demand case of more than 26,000 MW by 2030, and helps push the new mid case above *CEDU 2016* by around 3,300 MW in 2027. As shown in **Figure 16**, baseline self-generation overall is projected to reduce annual energy load provided by utilities by about 46,000 GWh in the new mid case by 2027, an increase of around 6,000 GWh compared to *CEDU 2016*. Most of the increase in self-generation over the forecast period comes from PV, so that by 2030 PV is responsible for about 66 percent of energy from self-generation (50,500 GWh). For the high and low demand cases, the percentages are 53 percent (37,600 GWh) and 73 percent (63,900 GWh), respectively. The demand forms accompanying this report[29] provide annual results for energy and peak impacts for total self-generation and PV for each planning area and statewide.

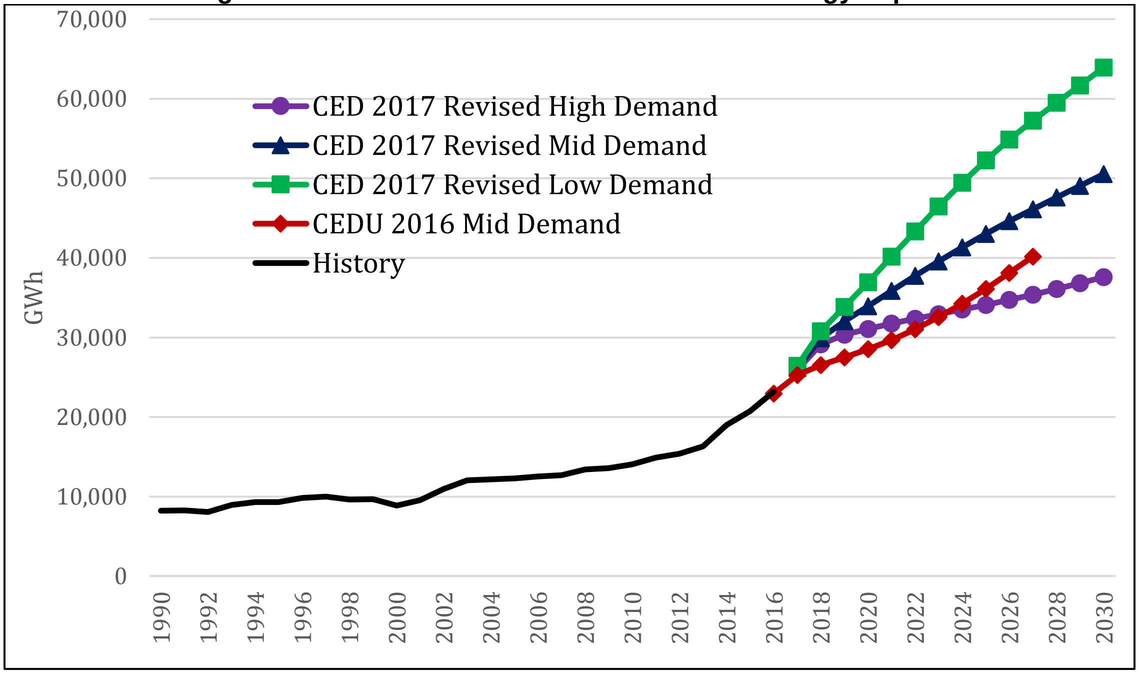
29 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

Figure 15: Statewide PV Capacity



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 16: Statewide Self-Generation Annual Energy Impact



Source: California Energy Commission, Energy Assessments Division, 2017.

Committed Conservation/Efficiency Impacts

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

CED 2017 Revised includes estimated committed efficiency impacts not included in *CEDU 2016*, from 2016 — 2017 programs for both IOUs and publicly owned utilities. In addition, staff has revised the estimated savings from 2010 — 2015 IOU programs based on the most recent CPUC evaluation, measurement, and verification (EM&V) study.[30] The study showed that actual realization of savings was below that anticipated for the 2010 — 2012 IOU programs, and staff applied adjustment factors to 2010 — 2015 savings embedded in the forecast to account for this difference.

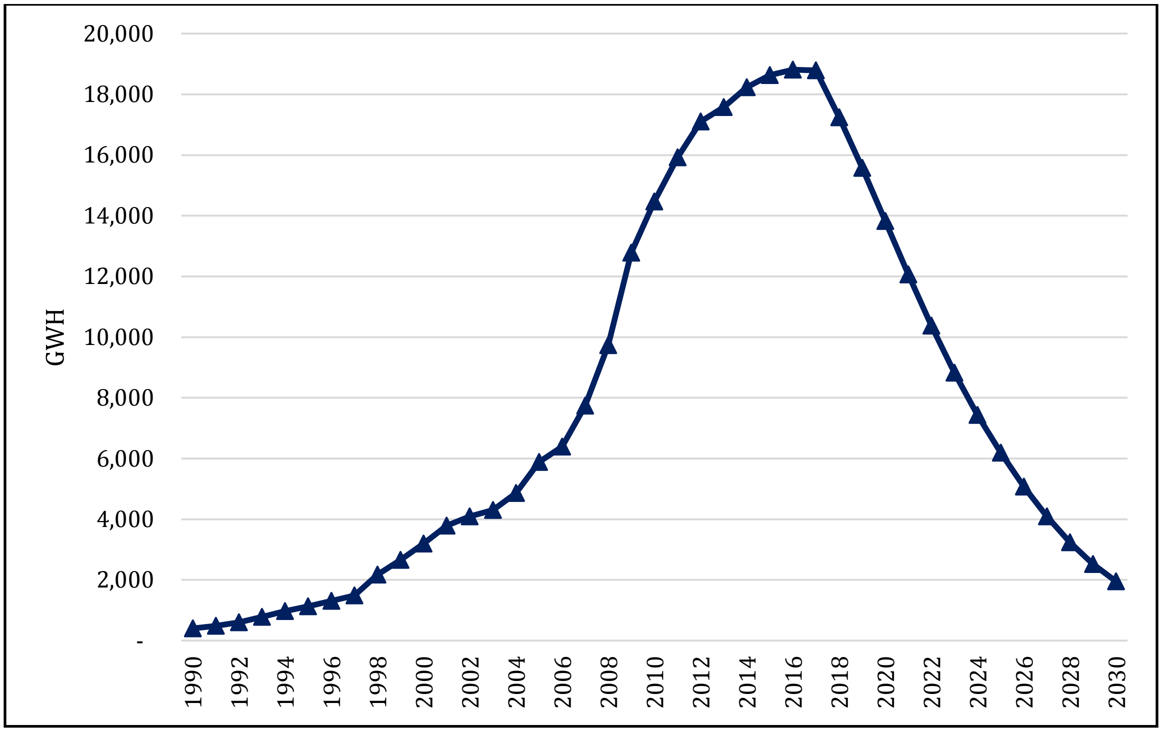
Figure 17 shows estimated historical and projected committed utility program savings for electricity statewide,[31] which reach around 18,800 GWh by 2017. **Figure 18** shows natural gas program savings, which reach about 220 million therms by the same year. Since these are committed programs, no new savings are added after 2017, and therefore the totals drop quickly[32] as program measures from previous years reach the end of their useful life. The decline after 2017 is counterbalanced by AAEE savings, discussed in the next chapter.

30 http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/Energy_Efficiency_2010-2012_Evaluation_Report.htm. EM&V results for 2013-15 were not completed in time to be used for *CED 2017 Revised*.

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

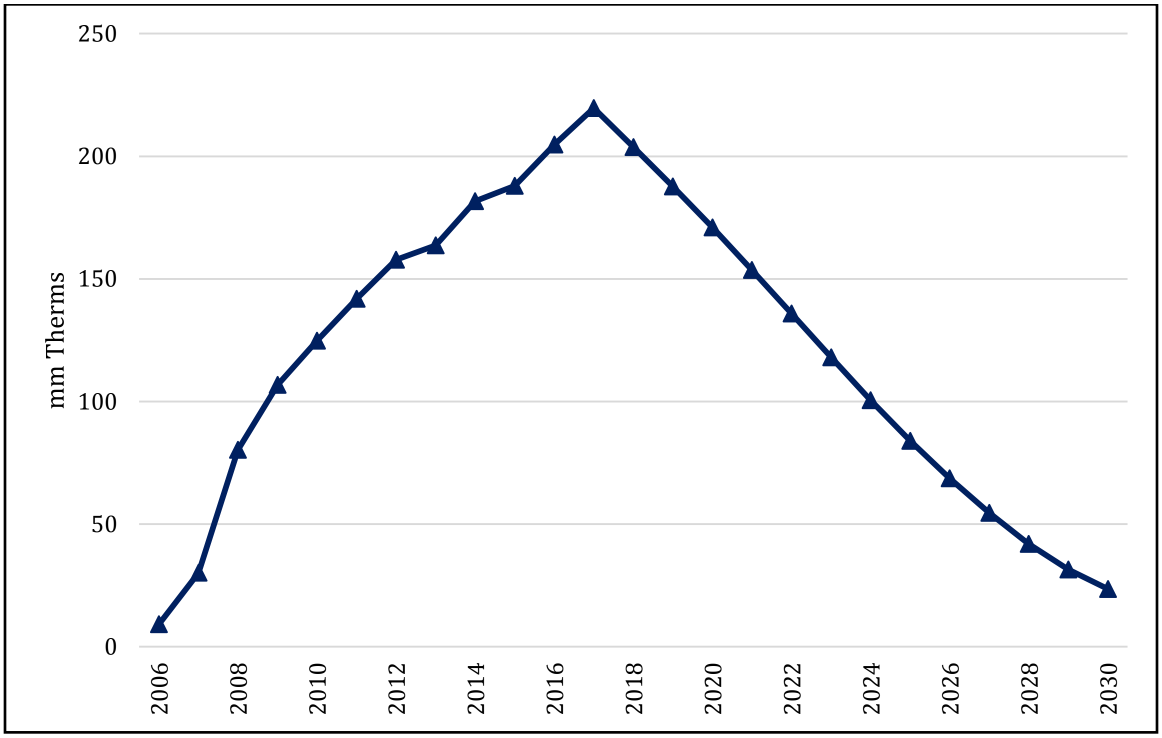
32 Many program measures have relatively short useful lives, particularly lighting measures, which make up a significant fraction of the total.

Figure 17: Statewide Committed Utility Efficiency Program Electricity Savings, 1990 — 2030



Source: California Energy Commission, Energy Assessments Division, 2017.

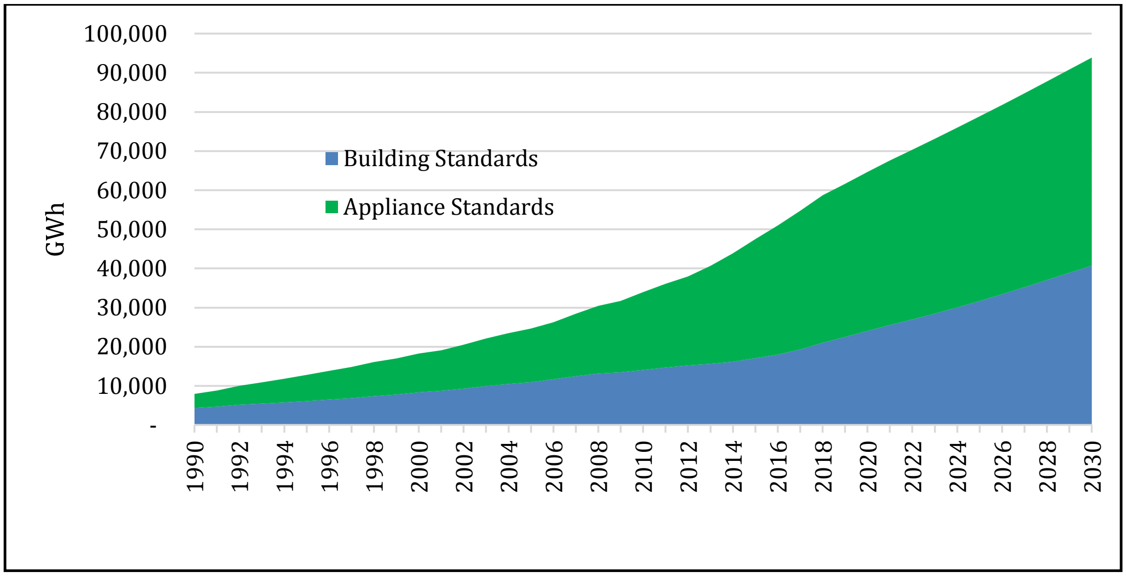
Figure 18: Statewide Committed Utility Efficiency Program Natural Gas Savings, 2006 — 2030



Source: California Energy Commission, Energy Assessments Division, 2017.

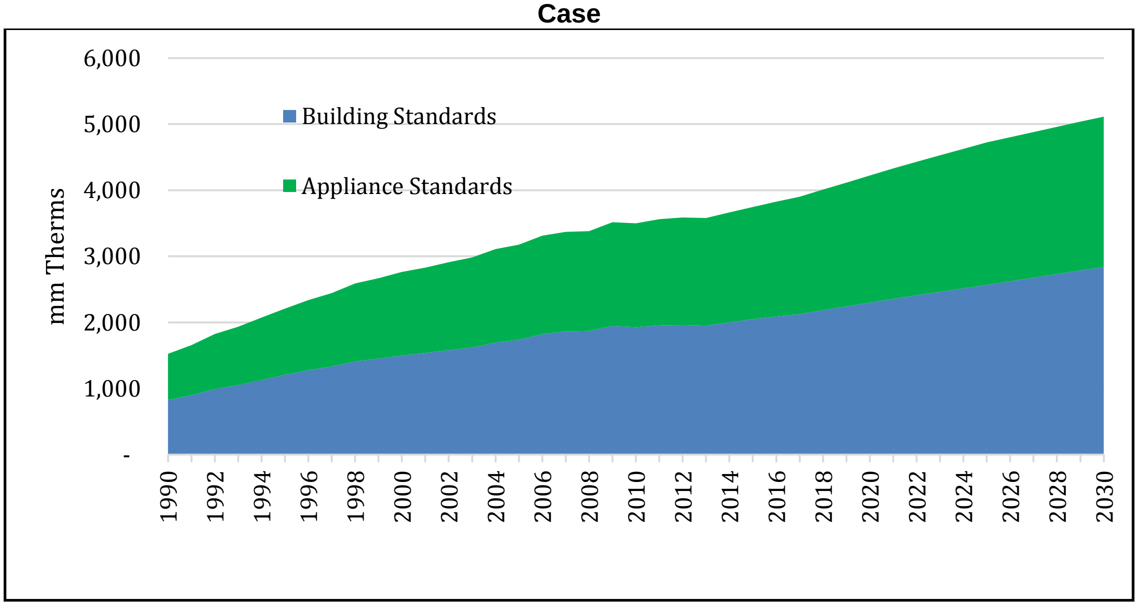
Estimated savings from committed standards for electricity and natural gas are shown in **Figure 19** and **Figure 20**, respectively, for the *CED 2017 Revised mid case*, split into building and appliance standards. The savings represent an accumulation of annual impacts beginning in 1975, and are expected to reach more than90,000 GWh for electricity and more than 5,000 mm therms for natural gas by 2030. The high and low cases, because of more or less projected building construction, yield a difference of 2-4 percent higher or lower savings during the forecast period relative to the mid case. Future likely-to-occur standards are included in AAEE savings.

Figure 19: Electricity Savings, Building and Appliance Standards, *CED 2017 Revised* Mid Case



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 20: Natural Gas Savings, Building and Appliance Standards, *CED 2017 Revised* Mid Case



Source: California Energy Commission, Energy Assessments Division, 2017.

Light-Duty EVs

CED 2017 Revised incorporates a new light-duty EV forecast, developed by the TEFU in the fall of 2017. The EV forecast incorporates a new vehicle choice survey, completed in spring 2017, and includes projections of pure battery-electric (BEV) and plug-in hybrid vehicles (PHEV) in both the residential and nonresidential sectors. Three scenarios were developed for *CED 2017 Revised*, with assumptions consistent with the three demand cases.[33]

The new forecasts reflect a more optimistic outlook for EVs by both staff and stakeholders, based on recent trends in California as well as commitments to widespread EV use around the world. This optimism was incorporated in the vehicle choice model through additional vehicle class offerings, higher projections for vehicle range, and a "taste" parameter that put EVs on par with conventional vehicles in terms of general acceptance. A detailed description of the EV forecasts is posted online.[34]

Figure 21 shows projected statewide light-duty EV electricity consumption for the three *CED 2017 Revised* cases and the mid case from *CEDU 2016*. Consumption is higher in all three new cases compared to *CEDU 2016* through 2027, with the new mid case about 3,300 GWh above *CEDU 2016* in this year. Projected EV stock statewide in the *CED 2017 Revised* high, mid, and low cases reaches 3.9 million, 3.3 million, and 2.6 million vehicles, respectively, by 2030.

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

Other Transportation Electrification

Significant increases in other transportation-related electricity use in California are expected to occur through port, truck stop, and other electrification. In particular, regulations implemented by the CARB[35] are aimed at reducing emissions from container, passenger, and refrigerated cargo vessels docked at California ports. Electrification impacts projected for *CED 2015* (and used for *CEDU 2016*) were based on a 2015

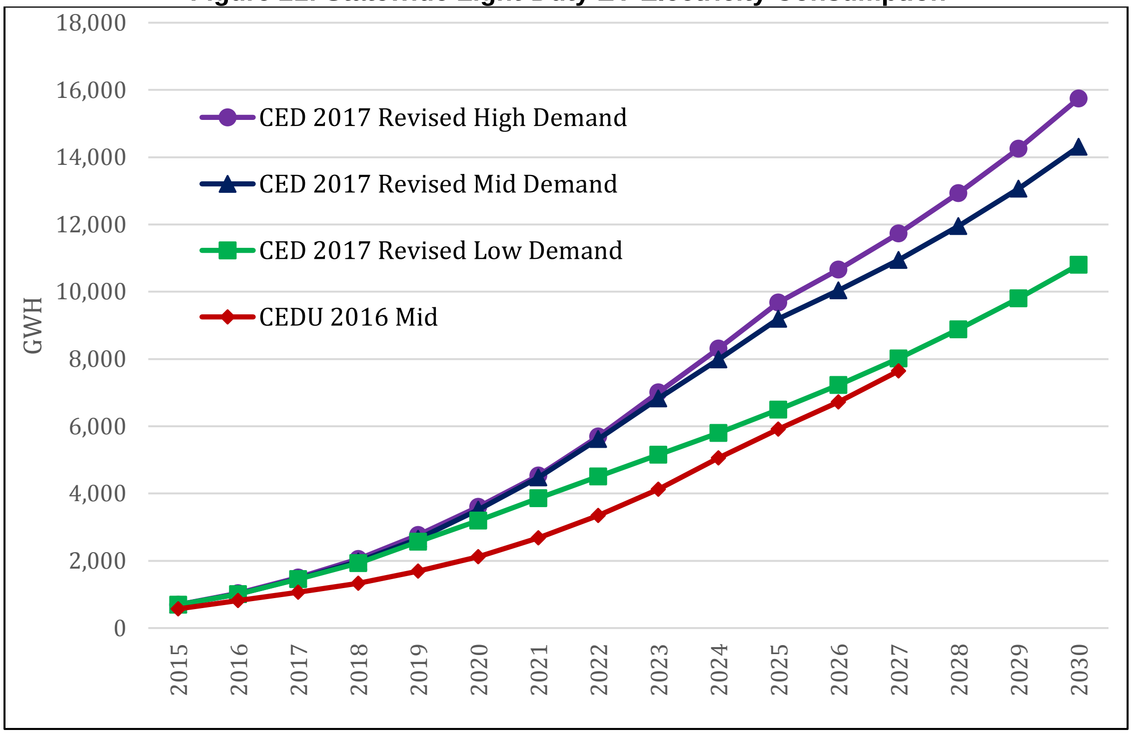
33 TEFU also developed higher "aggressive" and "bookend" scenarios for EVs, which were not used in this forecast.

34 Details on the vehicle choice forecasts are available in a transportation report here: http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-05/TN221893_20171204T085928_Transportation_Energy_Demand_Forecast_20182030.pdf.

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

consultant study for the Energy Commission,[36] which examined the potential for additional electrification in airport ground support equipment, port cargo handling equipment, shore power,[37] truck stops, forklifts, and transportation refrigeration units. For *CED 2017 Revised*, staff updated these impacts by incorporating new assumptions for gross state product (from the same Moody's forecasts discussed above), which drive increases in stock, and by extending the time frame to 2030. In addition, the TEFU provided estimates of electrified rail and medium- and heavy-duty trucks.

Figure 21: Statewide Light-Duty EV Electricity Consumption



Source: California Energy Commission, Energy Assessments Division, 2017.

As in *CED 2015*, transportation electrification includes high, mid, and low scenarios, representing aggressive, most likely, and minimal increases in electrification, respectively. Electrification impacts from the study were quantified at the state level. To incorporate them into the baseline forecast, it was necessary to allocate impacts across sector and planning area. Electrification impacts from port cargo handling equipment, shore power, truck stop electrification, and airport ground support were added to the transportation, communication, and utilities (TCU) sector. Impacts for transport refrigeration units and forklifts were assigned to multiple sectors, including industrial, TCU, and certain commercial building types. Given that some portion of electrification is

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

37 Power required for basic ship operations when berthed.

already embedded in *CED 2017 Revised* through extrapolation of historical trends, staff estimated *incremental* impacts of the updated projections.[38] 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 6**. Most of the impacts come from forklifts and shore power; together, these applications account for around 75 percent of the total.

Table 6: *CED 2017 Revised* Additional Electrification, Statewide (GWh)

Year	High Demand Case	Mid Demand Case	Low Demand Case
2017	134	89	53
2018	260	160	80
2019	395	232	101
2020	533	307	127
2021	638	357	135
2022	753	414	147
2023	881	478	162
2024	1,012	545	176
2025	1,150	615	194
2026	1,291	686	212
2027	1,341	718	231
2028	1,397	754	255
2029	1,496	834	322
2030	1,569	888	363

Source: California Energy Commission, Energy Assessments Division, 2017.

Climate Change

To estimate the potential of future climate change to impact electricity and natural gas consumption and peak demand,[39] staff used temperature scenarios developed by the Scripps Institution of Oceanography through a set of global climate change models, where results are downscaled to 50-square-mile grids in California. Multiple scenarios were generated by Scripps, and staff from the Energy Commission's Research and Development Division chose a "likely" and a more aggressive scenario for use in the *CED 2017 Revised* mid and high cases, respectively. The low demand case assumes no

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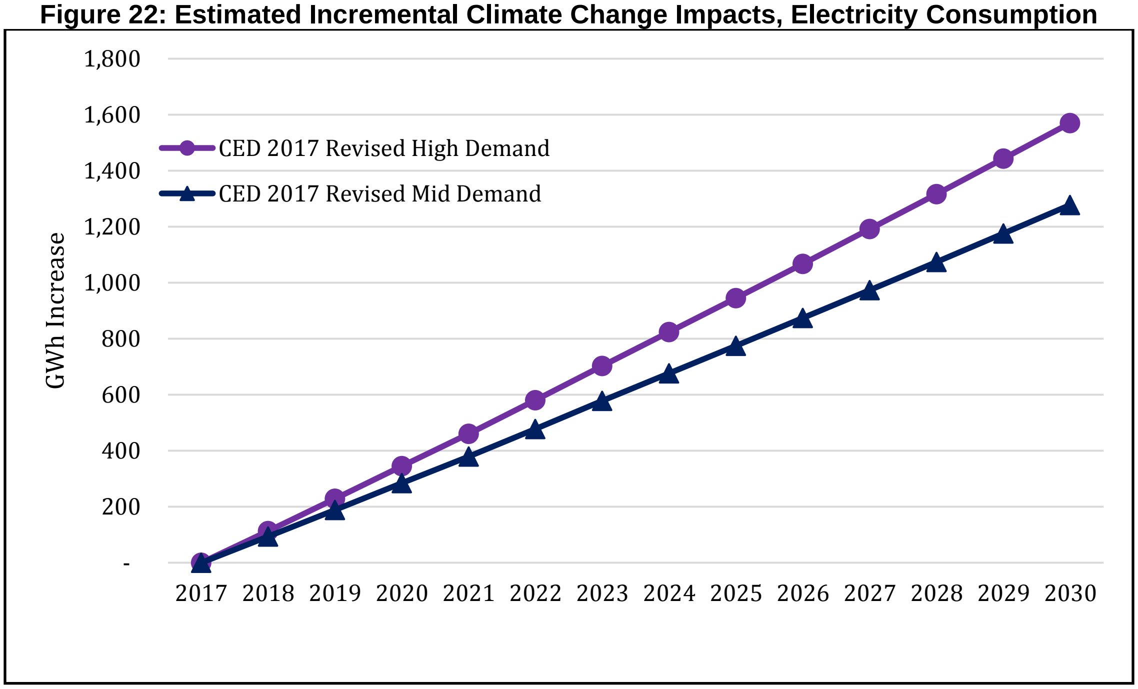
38 For example, shore power electricity would increase at roughly the rate of population growth within the TCU sector in the baseline forecast. Incremental impacts were calculated by applying population growth to current shore power estimates and then subtracting the results from the updated projections.

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

additional impacts from climate change. The high and low temperature scenarios are applied to weather-sensitive econometric models for residential and commercial sector annual consumption[40] for electricity and natural gas and for electricity peak demand to estimate consumption and peak impacts for each planning area and forecasting zone. The consumption models use cooling and heating degree days[41] for the weather parameter while the peak econometric model uses annual maximum temperatures. Econometric results with the high and mid temperature scenarios are compared to results with no temperature changes to estimate climate change impacts.

Figure 22 and **Figure 23** show estimated climate change impacts on statewide annual electricity and natural gas consumption, respectively. For electricity, the impacts are the net effect of increasing cooling degree days (more electricity use) and decreasing heating degree days (less use). In the case of natural gas, climate change decreases consumption through decreasing heating degree days, since cooling is not a significant end use for this fuel. **Figure 24** shows the impact on statewide noncoincident peak electricity demand, which reaches almost 800 MW by the end of the forecast period, corresponding to slightly more than a one percent increase.

Figure 22: Estimated Incremental Climate Change Impacts, Electricity Consumption

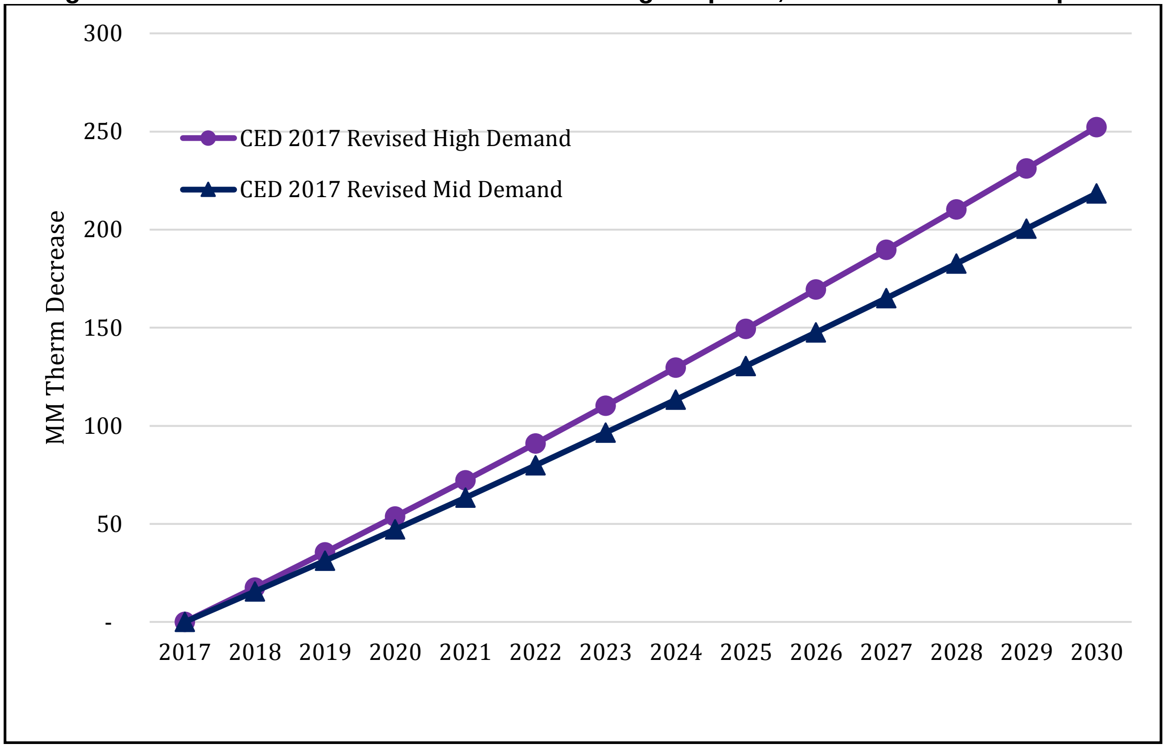


Source: California Energy Commission, Energy Assessments Division, 2017.

40 Other sectors show no significant temperature sensitivity for consumption.

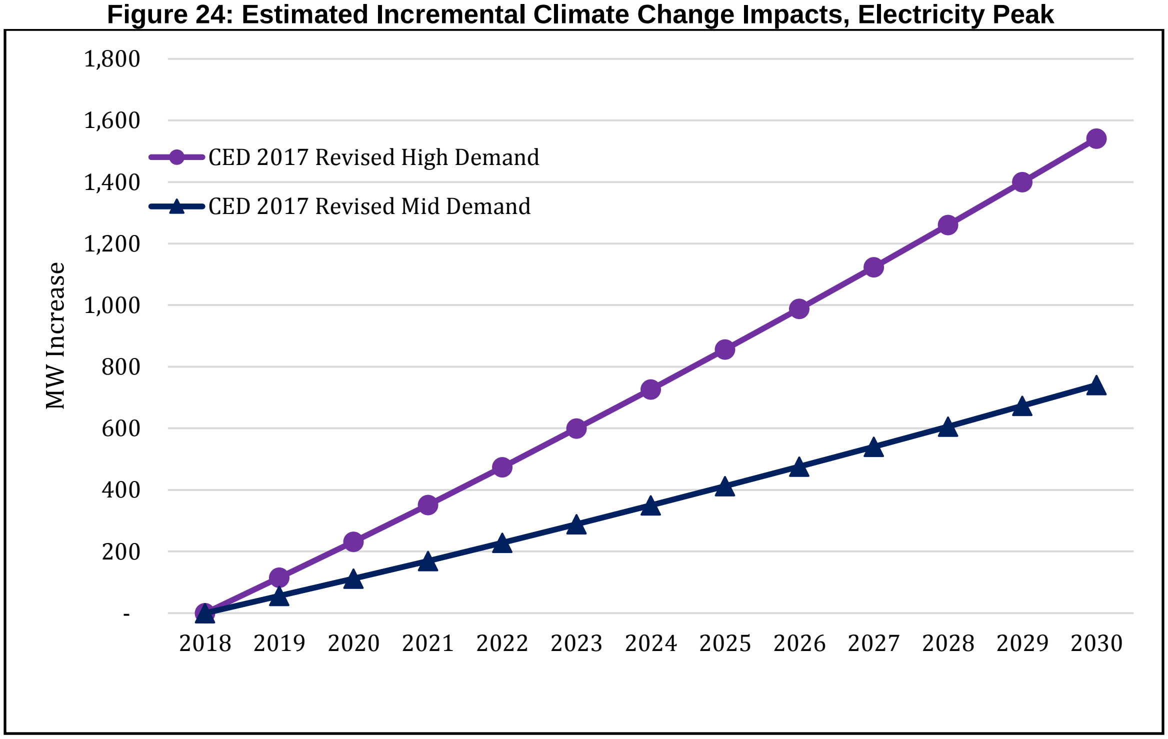
41 Relative to a benchmark of 65 degrees Fahrenheit.

Figure 23: Estimated Incremental Climate Change Impacts, Natural Gas Consumption



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 24: Estimated Incremental Climate Change Impacts, Electricity Peak



Source: California Energy Commission, Energy Assessments Division, 2017.

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 such nonevent-based programs have traditionally been included in the *IEPR* demand forecasts. More specifically, expected impacts incremental to the last historical year for peak (2017) affect the demand forecast.[42]

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

Staff bases demand response estimates on annual IOU demand response filings.[43] Projected nonevent-based program impacts are shown in **Table 7,** and event-based program impacts from the two pricing programs are in **Table 8**, by IOU. Combined impacts from these programs reach 89 MW for PG&E, 95 MW for SCE, and 23 MW for SDG&E by 2027 (remaining years are assumed the same as 2027). The total (noncoincident) reduction over all utilities from critical peak pricing, peak-time rebate, and nonevent programs amounts to almost 200 MW in 2027.

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42 Incremental impacts only would be counted since historical peaks would incorporate reductions in demand already occurring.

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

Table 7: Estimated Nonevent-Based Demand Response Program Impacts (MW)

Year	PG&E	SCE	SDG&E
2017	0	0	0
2018	12	4	0
2019	24	6	1
2020	3	6	1
2021	4	6	2
2022	4	7	2
2023	5	7	2
2024	7	7	3
2025	7	7	2
2026	8	7	2
2027*	9	7	2
*Program cycles end in 2027; 2028-2030 values assumed the same as 2027.			

Source: California Energy Commission, Energy Assessments Division, 2017.

Table 8: Estimated Demand Response Program Impacts: Critical Peak Pricing and Peak-Time Rebate Programs (MW)

Year	PG&E	SCE	SDG&E
2016	48	61	61
2017	61	28	18
2018	74	36	18
2019	75	46	18
2020	77	65	19
2021	78	58	20
2022	78	63	20
2023	78	68	21
2024	79	73	21
2025	79	78	21
2026	79	83	21
2027*	80	88	21
*Program cycles end in 2027; 2028-2030 values assumed the same as 2027.			

Source: California Energy Commission, Energy Assessments Division, 2017.

Residential TOU programs, currently small-scale and limited, are included in the nonevent-based program estimates until 2020. These programs are expected to be expanded significantly beginning in this year, and impacts for 2020 and beyond are included in the hourly load forecasts and described in **Chapter 3**.

Cannabis Legalization for Recreational Use

Formal legalization of cannabis for recreational use begins in various California cities and counties on January 1, 2018. Legalization creates concerns from an energy point of view because cultivation can be quite energy intensive. **Appendix B** discusses the potential ramifications for the electricity grid of cannabis legalization. Staff did not attempt to develop a specific forecast of legalization energy impacts for *CED 2017 Revised* given the uncertainties. By the time of the *2019 IEPR*, sufficient information may be available to fully incorporate cannabis legalization into the demand forecast.

Subregional Forecasts and Community Choice Aggregators

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.[44] 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 are expected to play an increasingly prominent role in California's energy future and to contribute to the state's efficiency and renewable goals. There are 15 CCAs currently operating or expected to be operating within the next year, up from 3 when *CED 2015* was developed. Staff developed best estimates of projected load in 2018 and 2019, with growth thereafter set to the average for the overall planning area. Some CCAs may see significant expansion after 2019, so this is likely a conservative forecast. Staff will update CCA projections to account for evidence of coming expansion as well as likely new entries in the IEPR forecast update to be developed later this year.

Organization of Report

The remainder of the report is organized as follows. **Chapter 2** discusses AAEE savings, including analysis for programs and standards evaluated for SB 350 not considered in the "traditional" estimation of AAEE. The chapter also includes discussion of a new element in the forecast, AAPV. **Chapter 3** describes the hourly load model, used to estimate the impact of peak shift for the IOU planning areas. The discussion also includes hourly PV generation (including AAPV) and hourly load shapes for electric vehicles, residential TOU pricing, and AAEE. **Chapter 4** provides the key forecast results for the five major electricity and three major natural gas planning areas. **Appendix A** describes the self-generation forecasts and **Appendix B** examines potential energy impacts associated with legalized cannabis.

44 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

CHAPTER 2: Additional Achievable Energy Efficiency and Photovoltaic Adoption

Introduction

For resource planning purposes, baseline Energy Commission demand forecasts are adjusted to a managed forecast by accounting for additional achievable energy efficiency savings. *CED 2017 Revised* adds two additional elements to this adjustment: savings beyond "traditional" AAEE estimated in support of SB 350 and additional achievable PV adoption, manifested through the 2019 Title 24 residential building standards update in support of Zero Net Energy goals.[45]

Investor-Owned Utility Service Territory AAEE

AAEE impacts for the IOU service territories are based on the CPUC's *Energy Efficiency Potential and Goals Study for 2018 and Beyond (2018 Potential Study)*.[46]

Method

The *2018 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 2013 — 2030,[47] given current or soon-to-be-available technologies. Because many of these savings are already incorporated in the Energy Commission's *CED 2017 Revised* baseline forecast, staff needed to estimate the portion of savings from the *2018 Potential Study* not accounted for in the baseline forecasts: programs from 2018 onward and codes and standards implemented after the 2016 Title 24 updates. These nonoverlapping totals become AAEE savings.

Energy Commission and Navigant Consulting staff developed five AAEE scenarios similar in concept to those used for *CED 2015*.[48] These scenarios are 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. In addition, because of SB 350 goals, staff and Navigant developed a more optimistic "what if"

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45 Total AAEE savings are therefore composed of "traditional" AAEE and additional savings estimated in support of SB 350.

46 Report and other information available at http://www.cpuc.ca.gov/General.aspx?id=6442452619.

47 The analysis begins in 2013 because results are calibrated using the CPUC's Standard Program Tracking Database, which tracks program activities through 2013.

48 Described in pages 54-65. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf.

scenario to be paired with the mid demand case, referred to as high plus savings. These six scenarios are then defined by the demand case and AAEE savings scenario (high, high plus, 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)
- Scenario 6: Mid Demand-High Plus AAEE Savings (mid-high plus)

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 mid-mid and mid-low scenarios are designated as the options to be applied to the *CED 2017 Revised* mid baseline forecast to yield a managed forecast or forecasts for planning purposes. Input assumptions for the five scenarios are shown in **Table 9**. Savings from codes and standards are adjusted using compliance rates that vary by individual measure developed by Navigant (available from staff upon request), Navigant's assessment of "naturally occurring" adoptions of measures applied in this category, and "uncertainty factors" meant to represent observed differences between predicted and realized savings.[49]

49 For a full description, see Section 3.7 and Appendix E of *Energy Efficiency Potential and Goals Study for 2018 and Beyond*, ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/DAWG/2018_Potential%20and%20Goals%20Study%20Final%20Report_092517.pdf.

Table 9: IOU AAEE Savings Scenarios

Demand Case	High	Mid	Mid	Mid	Low	Mid
Savings Scenario	Low (Scenario 1)	Low (Scenario 2)	Mid (Scenario 3)	High (Scenario 4)	High (Scenario 5)	High Plus (Scenario 6)
Building Stock	High Demand Case	Mid Demand Case	Mid Demand Case	Mid Demand Case	Low Demand Case	Mid Demand Case
Retail Prices	High Demand Case	Mid Demand Case	Mid Demand Case	Mid Demand Case	Low Demand Case	Mid Demand Case
Res/Com ETs	50% of model Results	50% of model Results	100% of model results	150% of model results	150% of model results	150% of model results
AIMS ETs	Reference	Reference	Reference	Reference	Reference	Aggressive
Incentive Level	Reference	Reference	Reference	Reference	Reference	Aggressive
C/E Threshold	1	1	0.85	0.75	0.75	0.75
ET C/E Threshold	0.85	0.85	0.5	0.4	0.4	0.4
Cost-Effectiveness Test	mTRC(GHG Adder #1)	mTRC(GHG Adder #1)	mTRC(GHG Adder #1)	mTRC(GHG Adder #1)	mTRC(GHG Adder #1)	PAC
Marketing Effect	Reference	Reference	Reference	Aggressive	Aggressive	Aggressive
Financing	Reference	Reference	Reference	Aggressive	Aggressive	Aggressive
BROs Interventions	Reference	Reference	Reference	Reference	Reference	Aggressive
Low Income	First Time + 50% Retreatment	First Time + 50% Retreatment	First Time + Retreatment	First Time + Retreatment	First Time + Retreatment	First Time + 150% Retreatment
Compliance Reduction	20% Compliance Rate Reduction	20% Compliance Rate Reduction	No Compliance 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	Compliance Enhancements
Title 24	No additional Codes	2019 T24 (except NR A&A)	2019 T24 (except NR A&A)	2019 T24 (except NR A&A)	2019 T24 (except NR A&A)	2019 T24 (except NR A&A)
Title 20	2018 T20	2018 T20	2018-2024 T20	2018-2024 T20	2018-2024 T20	2018-2024 T20
Federal Standards	On-the-books	On-the-books	On-the-books	On-the-books	On-the-books	On-the-books

Sources: Navigant Consulting and California Energy Commission, Energy Assessments Division, 2017.

The following summarizes the parameters/assumptions used in constructing the five scenarios. More information can be found in the *2018 Potential Study* report.[50]

1. *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.
2. *Emerging Technologies (ETs)*: The *2018 Potential Study* introduced emerging technologies for the agricultural, industrial, and mining sectors (AIMS). Residential and commercial emerging technologies were handled similarly to *CED 2015* by modifying the percentage of model results.
3. *Cost-Effectiveness Test*: For the *2018 Potential Study*, Navigant, at CPUC's direction,[51] used a modified total resource cost (mTRC) test, with a specified adder for greenhouse gas incorporated into avoided costs, and this was applied to Scenarios 1-5. The mid-high plus scenario uses the more permissive program administrator cost (PAC) test.
4. *Marketing 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.
5. *Financing:* Financing of individual measures is designed to break through market barriers that have limited the widespread adoption of energy efficient technologies. Financing impacts are modeled as reductions in consumer implied discount rates. 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.
6. *Behavior, Retrocommissioning, and Operational Savings (BROs)*: In support of Assembly Bill 802 (AB 802, Williams, Chapter 590, Statutes of 2015), Navigant provided expanded coverage of BROs in the *2018 Potential Study*. The reference case is dominated by savings derived from residential home energy reports while the aggressive case includes less well-known interventions that have significant savings potential.

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50 ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/DAWG/2018_Potential%20and%20Goals%20Study%20Final%20Report_092517.pdf.

51 CPUC Decision 16-08-019: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=166232537.

7. *Low Income Programs*: Savings from these programs are based on a forecast of participation derived from IOU program filings. Retreatment refers to installing new and updated measures in homes that have been served by past low income program activity.

8. *Codes and Standards*: Codes and standards likely to be implemented are handled similarly to *CED 2015*, with compliance reductions and compliance enhancements[52] varying as shown. For Title 24 building standards updates, the *2018 Potential Study* did not go beyond 2019 (and did not include non-residential additions and alterations) due to lack of information at the time. The analysis for additional SB 350 savings, discussed later in this chapter, includes estimated savings from additional ratchets for building and appliance standards, including the missing piece for 2019 Title 24.

Summary of Results

This section summarizes AAEE projections for the IOUs. Spreadsheets with detail by sector and end use for each service territory are posted with the report.[53]

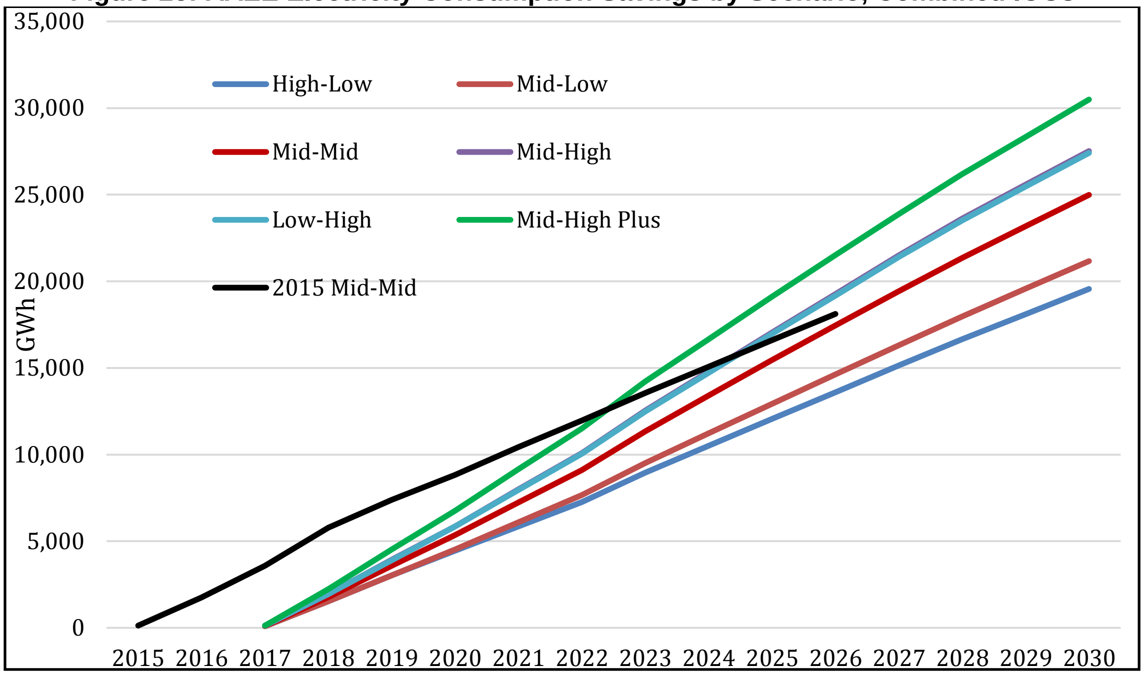
Figure 25, **Figure 26**, and **Figure 27** show estimated AAEE savings by scenario for the IOUs combined for electricity consumption, electricity peak demand, and natural gas consumption, respectively. It is important to note that the peak savings are presented for reference purposes; final projected peak savings will depend on the amount of peak shift estimated for each IOU and are provided in **Chapter 4**. For comparison, the *CED 2015* mid-mid scenario is also included in each figure.

AAEE savings reach roughly 25,000 GWh of electricity consumption savings, 6,900 MW of peak savings, and 650 mm therms of natural gas consumption savings in Scenario 3 (mid-mid). In the mid-high plus scenario, savings reach over 30,000 GWh, over 9,000 MW, and almost 900 mm therms by 2030. Totals for the low-high and mid-high scenarios are very similar because the impacts of building stock and electricity rates work in opposite directions and nearly offset each other exactly. The curve for the *CED 2015* mid-mid scenario shows savings in 2016 and 2017 that are now part of the baseline forecast. Natural gas consumption savings in the new mid-mid scenario rise above *CED 2015* at an earlier point than electricity consumption and peak because the updated BROs and low income measures included in the *2018 Potential Study* have the largest relative impact on natural gas.

52 This means increases in assumed compliance, to reach 100 percent by 2030.

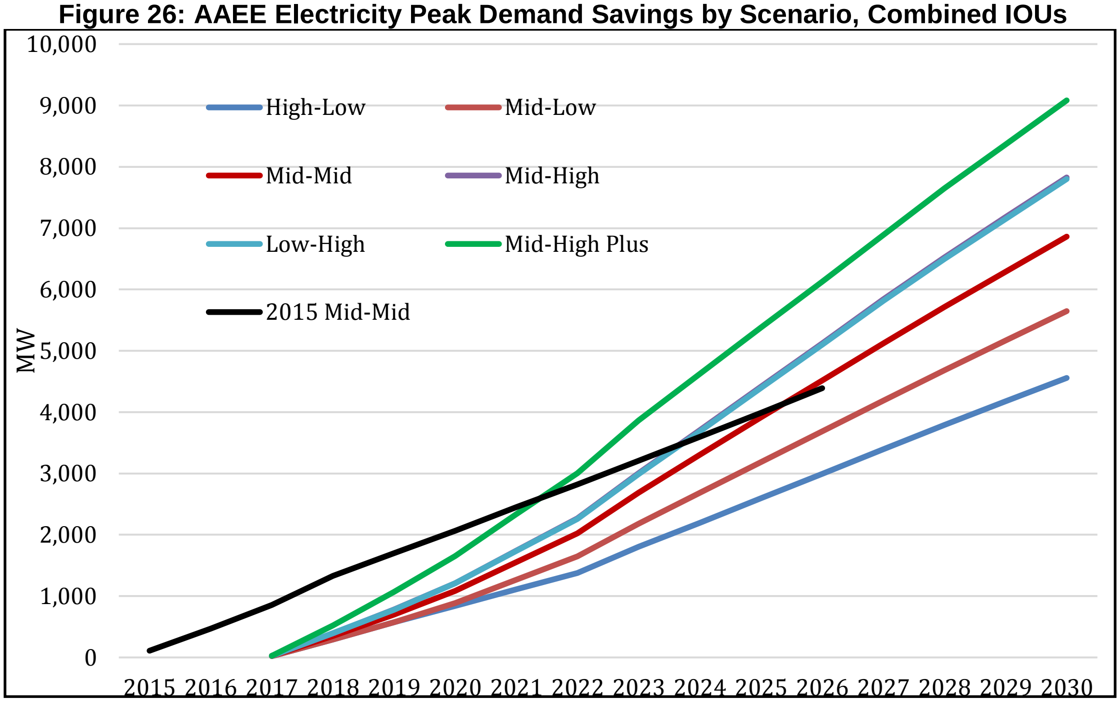
53 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

Figure 25: AAEE Electricity Consumption Savings by Scenario, Combined IOUs



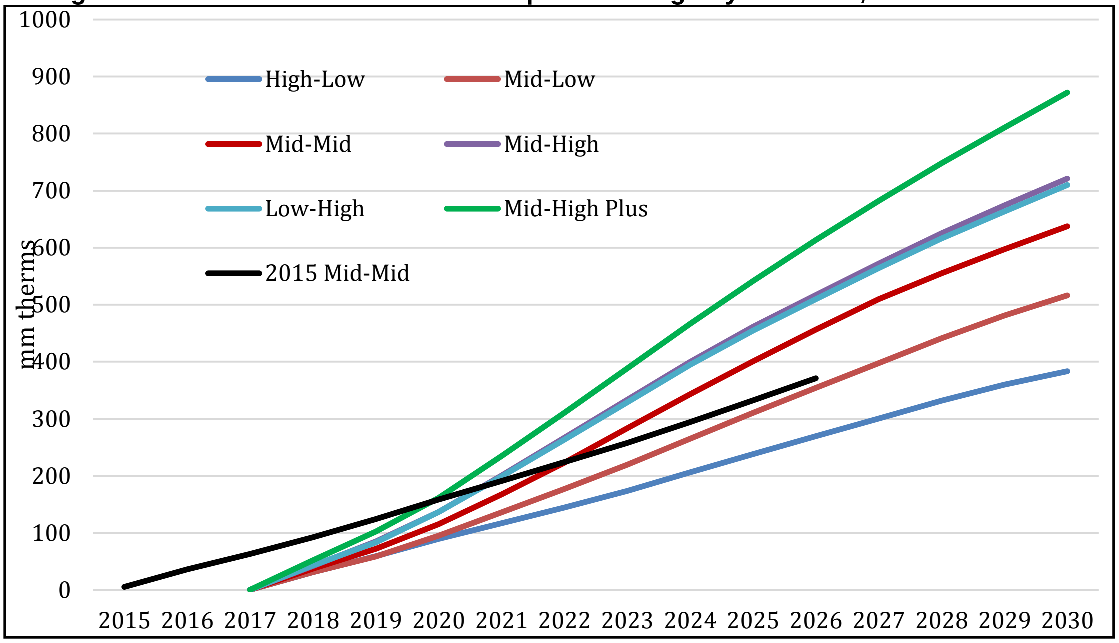
Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 26: AAEE Electricity Peak Demand Savings by Scenario, Combined IOUs



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 27: AAEE Natural Gas Consumption Savings by Scenario, Combined IOUs



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 10, **Table 11**, and **Table 12** show estimated AAEE savings by source for the IOUs combined in the mid-mid scenario for electricity consumption, electricity peak demand, and natural gas consumption, respectively. Standard equipment incentive programs provide the most GWh for this scenario, while appliance standards, with more HVAC impacts, provide the highest (reference) peak savings. Equipment incentives also provide the highest natural gas consumption savings, with appliance standard totals now negative because of the lighting interactive effect from electricity lighting standards.

Table 10: AAEE Savings by Source (GWh), Combined IOUs, Scenario 3 (Mid-Mid)

Year	Low Income	BROs	Equipment (Standard)	Equipment (ET)	Appliance Standards	Building Standards	Total
2017	--	--	--	--	123	--	123
2018	57	213	659	103	746	--	1,778
2019	114	305	1,391	235	1,537	--	3,582
2020	171	377	2,154	321	2,255	86	5,363
2021	204	426	2,922	445	2,946	305	7,248
2022	237	474	3,700	577	3,602	520	9,109
2023	269	520	4,467	720	4,637	730	11,343
2024	302	565	5,262	873	5,475	935	13,413
2025	335	610	6,084	1,037	6,258	1,136	15,459
2026	363	656	6,917	1,206	6,976	1,333	17,451
2027	392	707	7,791	1,381	7,640	1,525	19,437
2028	420	760	8,717	1,568	8,174	1,714	21,352
2029	419	816	9,633	1,764	8,642	1,899	23,172
2030	402	869	10,585	1,969	9,072	2,082	24,979

Source: California Energy Commission, Energy Assessments Division, 2017.

Table 11: AAEE Savings by Source (MW), Combined IOUs, Scenario 3 (Mid-Mid)

Year	Low Income	BROs	Equipment (Standard)	Equipment (ET)	Appliance Standards	Building Standards	Total
2017	--	--	--	--	24	--	24
2018	10	39	124	29	146	--	347
2019	20	54	263	66	294	--	697
2020	30	65	410	92	430	56	1,084
2021	36	72	558	127	561	200	1,556
2022	42	80	708	166	684	341	2,021
2023	48	87	861	207	1,002	479	2,683
2024	53	95	1,020	250	1,273	613	3,305
2025	59	102	1,182	297	1,531	745	3,916
2026	64	110	1,348	344	1,778	874	4,518
2027	70	118	1,525	393	2,015	1,000	5,121
2028	75	126	1,715	446	2,229	1,124	5,715
2029	75	136	1,906	501	2,427	1,246	6,290
2030	71	144	2,106	558	2,619	1,366	6,864
NOTE: MW savings are for reference only and do not incorporate any peak shift impact.							

Source: California Energy Commission, Energy Assessments Division, 2017.

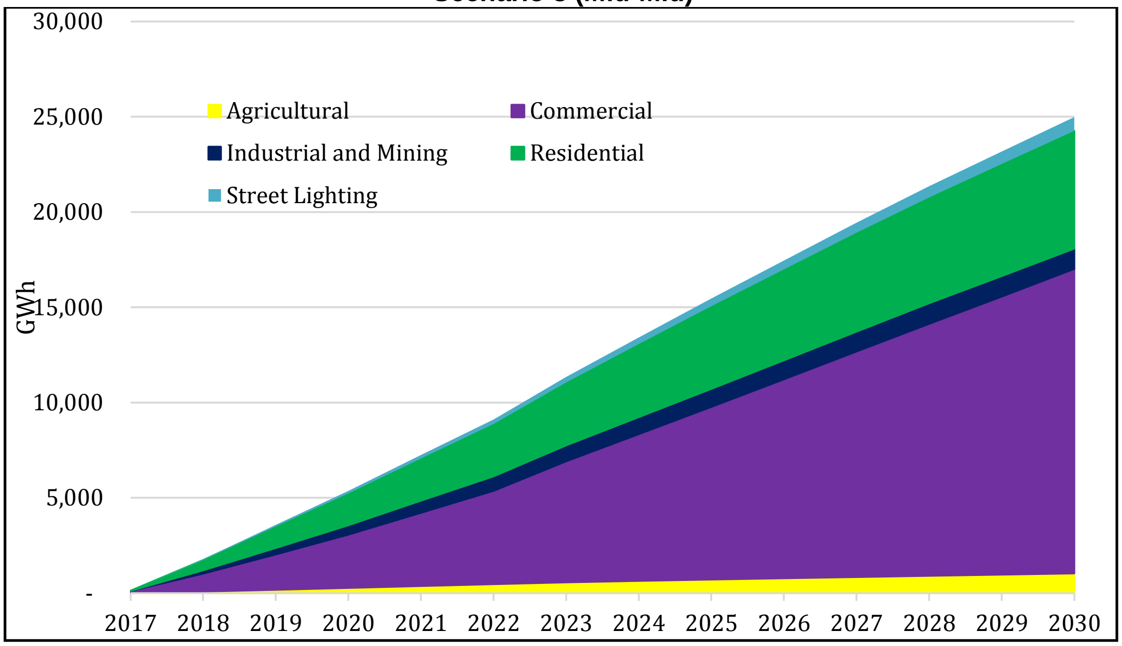
Table 12: AAEE Savings by Source (mm Therms), Combined IOUs, Scenario 3 (Mid-Mid)

Year	Low Income	BROs	Equipment (Standard)	Equipment (ET)	Appliance Standards	Building Standards	Total
2017	--	--	--	--	0	--	0
2018	6	7	23	4	-3	0	37
2019	12	12	46	10	-7	0	72
2020	18	17	69	13	-11	9	115
2021	23	18	95	17	-14	28	168
2022	28	19	124	22	-16	46	223
2023	33	21	157	27	-18	64	284
2024	38	22	188	32	-18	81	343
2025	43	24	216	38	-19	99	401
2026	48	25	242	44	-19	116	457
2027	53	27	265	51	-19	133	510
2028	56	28	281	59	-19	150	555
2029	55	30	296	67	-19	167	597
2030	55	32	310	76	-19	184	637

Source: California Energy Commission, Energy Assessments Division, 2017.

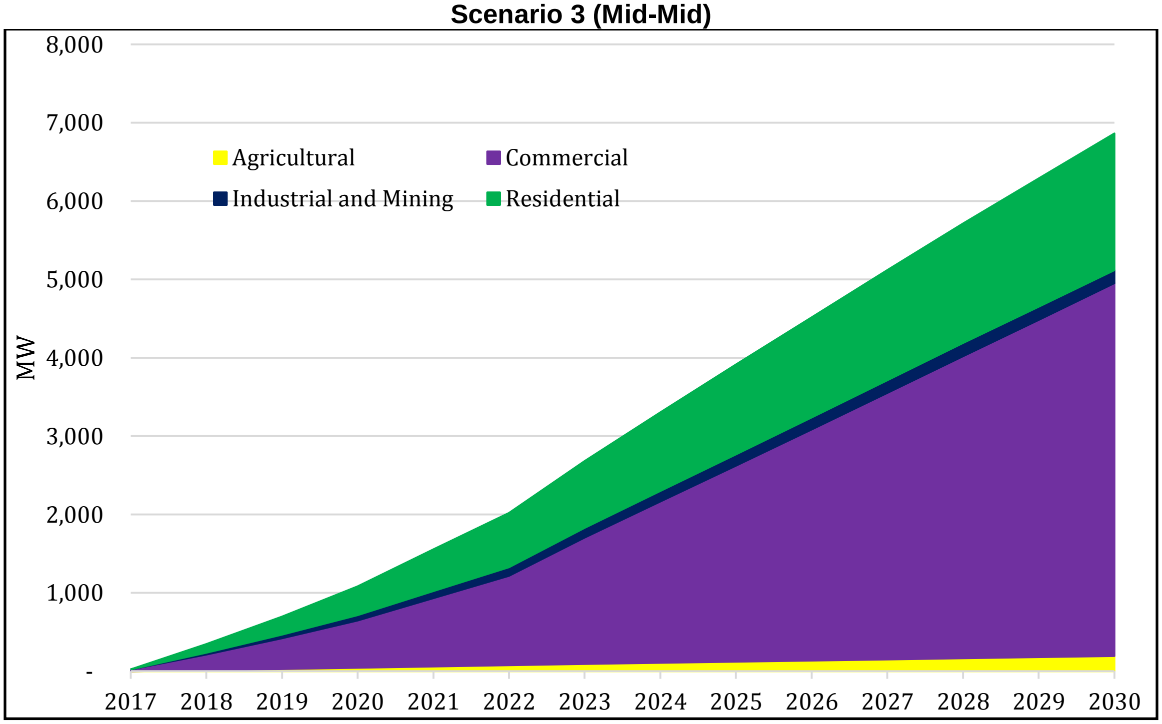
Figure 28, **Figure 29**, and **Figure 30** show estimated AAEE savings by sector in the mid-mid scenario for the IOUs combined for electricity consumption, electricity peak demand, and natural gas consumption, respectively. As in past recent forecasts, remaining opportunities for electricity efficiency improvements are highest in the commercial sector, which yields 64 percent of the total for GWh savings and 69 percent for MW savings by 2030. For natural gas, residential (59 percent by 2030) and industrial and mining (24 percent) savings dominate; the end-use natural gas commercial sector is relative small.

Figure 28: AAEE Electricity Consumption Savings by Sector, Combined IOUs, Scenario 3 (Mid-Mid)



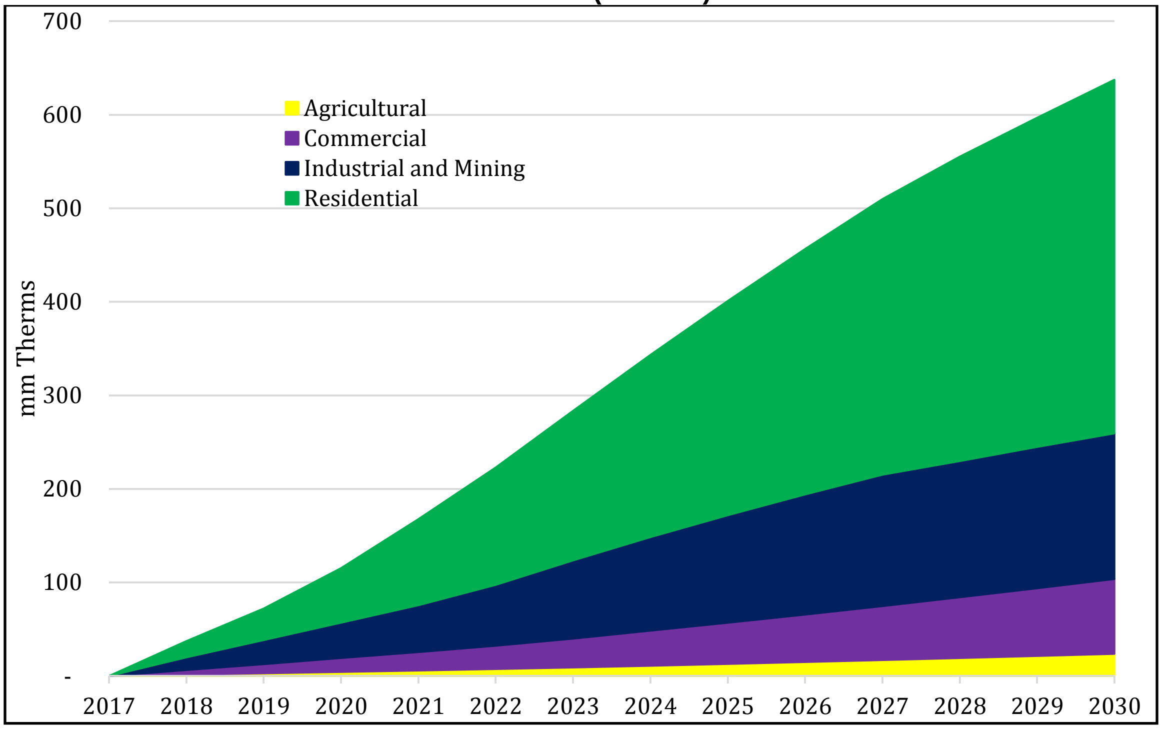
Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 29: AAEE Electricity Peak Demand Savings by Sector, Combined IOUs, Scenario 3 (Mid-Mid)



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 30: AAEE Natural Gas Consumption Savings by Sector, Combined IOUs, Scenario 3 (Mid-Mid)



Source: California Energy Commission, Energy Assessments Division, 2017.

Publicly Owned Utility Additional Achievable Energy Efficiency

For *CED 2017 Revised*, staff had planned to develop full scenario analyses for the large and medium-sized POUs with the help of a consultant. However, contract resources did not become available in time, so staff developed a scaled-back effort based on utility efficiency goals and the IOU *2018 Potential Study*.

The efficiency program portion of AAEE relied on the results of a POU potential study for 2018 — 2027 submitted to Energy Commission in March 2017. The projections for program savings in this study were developed by Navigant Consulting pursuant to a contract with the California Municipal Utility Association. The Energy Commission reviewed these projections as part of the SB 350 process and staff used these projections to develop a set of program targets for large and medium POUs that was adopted in November 2017.[54] Program projections submitted to the Energy Commission varied in form: some POU savings were measured as gross[55] and some included the impacts of codes and standards. For the adopted targets, staff, where necessary, converted gross savings to net (using agreed-upon net-to-gross ratios) and removed

54 CEC, *Senate Bill 350: Doubling Energy Efficiency Savings by 2030*, CEC Report Number CEC-400-2017-010-CMF, see http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-06/TN221631_20171026T102305_Senate_Bill_350_Doubling_Energy_Efficiency_Savings_by_2030.pdf.

55 Includes savings from “free riders.”

savings from codes and standards. For this forecast, these estimates were extrapolated to 2030. Staff processed the smaller POUs in the same manner, resulting in program streams for each of the 39 POUs submitting data for the SB 350 proceedings. Staff aggregated these savings into the appropriate planning areas, including the small POUs that are part of the PG&E and SCE planning areas. Unlike the IOU AAEE, POU future program savings have just a single scenario.

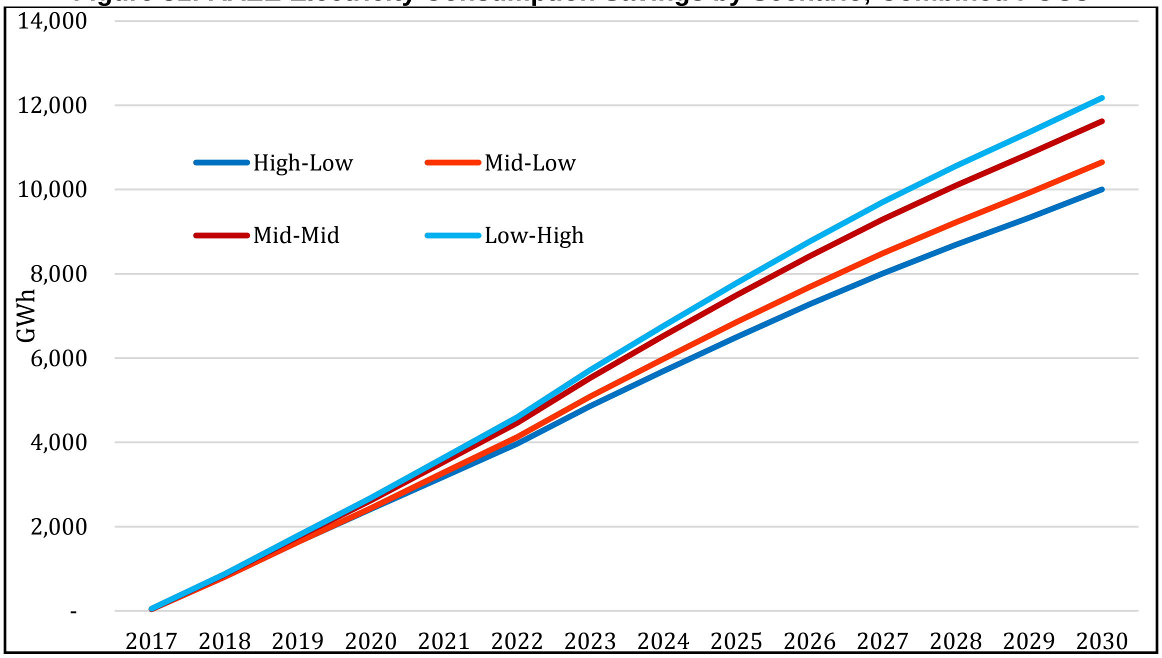
For the building and appliance standards portion of AAEE, staff inflated the IOU savings estimates for those future standards described in **Table 9** to statewide numbers using 2016 QFER sales data.[56] Next, standards savings were apportioned to POUs based on 2016 sales and then aggregated into the appropriate planning areas. Similar to the IOU case, six scenarios were created for codes and standards (see **Table 9**), although totals are identical for some of the scenarios. The same adjustments for compliance, naturally occurring adoptions, and uncertainty factors assumed for IOUs were applied to the POUs.

Figure 31 and **Figure 32** show combined POU results for electricity consumption and peak demand savings, respectively. With no variation in program savings across scenarios, the mid-high, low-high, and mid-high plus scenarios are identical and are shown as low-high. In the mid-mid scenario, consumption savings reach around 11,600 GWh and peak savings about 2,800 MW by 2030. These savings represent roughly 46 percent of the consumption savings and 41 percent of the peak savings estimated for the IOUs. For the POUs that are not in the California ISO territory, peak savings are applied as presented since these forecasts do not consider the peak shift; for the other POUs, peak savings are calculated through the hourly load model using estimated hourly load shapes, as for the IOUs.

Table 13 and **Table 14** show combined POU results by type of savings (standards or programs) by scenario for electricity consumption and peak demand savings, respectively. Program savings dominate, reflecting the relative aggressiveness of POU program goals. Results for individual POU planning areas are provided in **Chapter 4**.

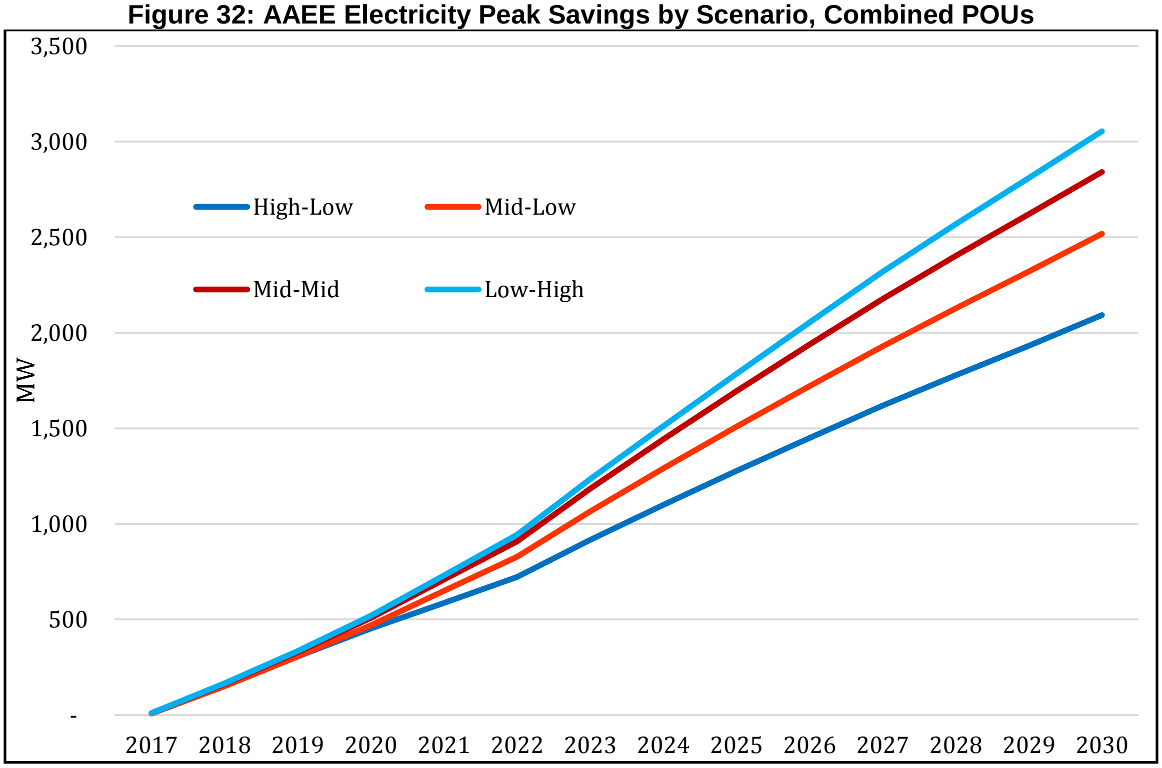
56 Specifically, this meant multiplying the standards savings by 1/ (ratio of the sum of the IOU service territory sales to total state sales). This is consistent with the method Navigant uses to apportion statewide standards savings to each of the IOU service territories, although in reverse.

Figure 31: AAEE Electricity Consumption Savings by Scenario, Combined POUs



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 32: AAEE Electricity Peak Savings by Scenario, Combined POUs



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 13: AAEE Consumption Savings by Source and Scenario (GWh), Combined POUs

	High-Low		Mid-Low		Mid-Mid		Low-High	
	Standards	Programs	Standards	Programs	Standards	Programs	Standards	Programs
2017	38	-	38	-	48	-	50	-
2018	232	570	232	570	290	570	302	570
2019	478	1,155	478	1,155	597	1,155	628	1,155
2020	701	1,711	728	1,711	910	1,711	966	1,711
2021	912	2,278	1,007	2,278	1,264	2,278	1,357	2,278
2022	1,111	2,854	1,272	2,854	1,602	2,854	1,739	2,854
2023	1,418	3,441	1,645	3,441	2,086	3,441	2,276	3,441
2024	1,658	4,031	1,949	4,031	2,492	4,031	2,729	4,031
2025	1,882	4,614	2,235	4,614	2,874	4,614	3,166	4,614
2026	2,088	5,186	2,502	5,186	3,229	5,186	3,579	5,186
2027	2,280	5,728	2,754	5,728	3,562	5,728	3,971	5,728
2028	2,440	6,251	2,973	6,251	3,843	6,251	4,303	6,251
2029	2,580	6,748	3,170	6,748	4,097	6,748	4,603	6,748
2030	2,713	7,287	3,360	7,287	4,335	7,287	4,885	7,287

Source: California Energy Commission, Energy Assessments Division, 2017.

Table 14: AAEE Peak Savings by Source and Scenario (MW), Combined POUs

	High-Low		Mid-Low		Mid-Mid		Low-High	
	Standards	Programs	Standards	Programs	Standards	Programs	Standards	Programs
2017	7	-	7	-	9	-	10	-
2018	45	106	45	106	57	106	59	106
2019	91	214	91	214	114	214	120	214
2020	134	318	151	318	189	318	201	318
2021	174	413	236	413	296	413	318	413
2022	211	510	317	510	398	510	432	510
2023	308	609	457	609	575	609	626	609
2024	390	709	580	709	733	709	803	709
2025	467	809	699	809	885	809	976	809
2026	542	908	814	908	1,031	908	1,147	908
2027	614	1,004	925	1,004	1,172	1,004	1,314	1,004
2028	679	1,099	1,029	1,099	1,303	1,099	1,470	1,099
2029	740	1,192	1,128	1,192	1,428	1,192	1,618	1,192
2030	800	1,293	1,224	1,293	1,549	1,293	1,761	1,293

Source: California Energy Commission, Energy Assessments Division, 2017.

Additional SB 350 Efficiency Savings

SB 350, the Clean Energy and Pollution Reduction Act of 2015, established for the State of California a new set of clean energy targets in support of the state's goal to reduce greenhouse gas emissions to 40 percent below 1990 levels by 2030. SB 350 requires the Commission to establish annual targets that achieve a cumulative doubling of projected statewide energy efficiency savings in electricity and natural gas end uses of retail customers by January 1, 2030. The doubling of projected energy efficiency savings called for in SB 350 pushes beyond the significant savings that are projected to be achieved by 2030 through California's existing plans for energy efficiency programs and activities, incorporated in the demand forecasts through AAEE.

The Efficiency Division of the Energy Commission brought on the consulting firm NORESCO to identify and estimate additional efficiency savings opportunities beyond utility programs.[57] Initiatives in the analysis included financing programs, Property Assessed Clean Energy (PACE), Local Government Challenge, Local Government Ordinances, Proposition 39, Energy Conservation Assistance Act, Greenhouse Act Reduction Fund (GGRF), Energy Savings Program (Department of General Services), Air Quality Management District programs, benchmarking and public disclosure, Energy Asset Rating, BROs, smart meters and controls, and fuel substitution, as well as additional ratchets of Title 24 building standards, Title 20 appliance standards, and Federal Appliance Standards. The ultimate goal of this work was to measure savings potential incremental to efficiency impacts included in the baseline demand forecast as well as from traditional AAEE.

NORESCO provides three scenarios for the identified efficiency initiatives: "conservative," "reference," and "aggressive." **Figure 33** shows the total potential statewide electricity consumption savings[58] for all the initiatives from the NORESCO analysis for each scenario. Potential savings reach 26,300 GWh by 2029 in the reference case, compared to total statewide AAEE (IOUs plus POUs) for the mid-mid scenarios from the previous sections of around 33,900 GWh in the same year. Staff used only the reference case is the work described below.

The question for staff was how to integrate these projected savings into the traditional AAEE paradigm. An important consideration is disparity between the purpose of the NORESCO analysis (to support SB 350 target-setting) and traditional AAEE projections. SB 350 targets represent savings that could occur if a series of assumptions are consistently pursue through time. Most important is that the assumed funding levels or

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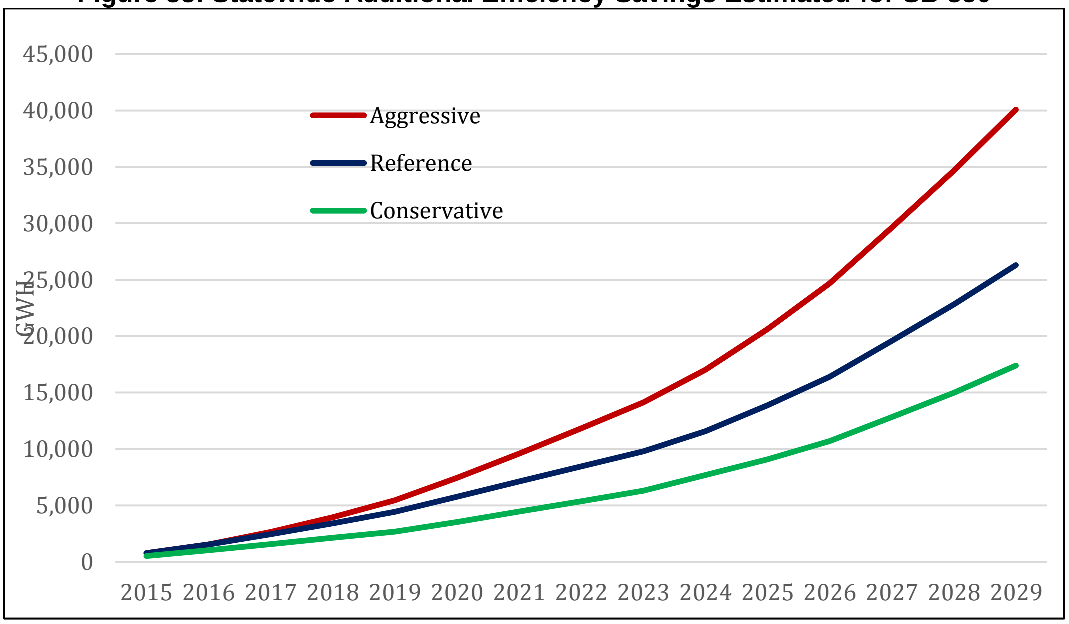
57 Work is detailed in Appendix B of an Energy Commission Report: Jones, Melissa, Michael Jaske, Michael Kenney, Brian Samuelson, Cynthia Rogers, Elena Giyenko, and Manjit Ahuja. 2017. *Senate Bill 350: Doubling Energy Efficiency Savings by 2030*. California Energy Commission. Publication Number: CEC-400-2017-010-CMF. Available at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-06/TN221631_20171026T102305_Senate_Bill_350_Doubling_Energy_Efficiency_Savings_by_2030.pdf Workbooks providing computations and results are available here: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-06.

58 NORESCO did not attempt to estimate peak demand savings.

other indicators critical to the scale of the program effort actually take place. For many of the programs analyzed by NORESCO, there is no assurance of such funding. In contrast, AAEE projections are intended to be used for actual resource procurement to satisfy projected managed energy demand or to replace other sources of generation that will be scaled back through time. In other words, AAEE projections as a supplement to the baseline demand forecast satisfy a statutory requirement that the adopted demand forecast included energy efficiency “reasonably expected to occur.” Therefore, staff developed an approach that sought to adapt the SB 350 analyses by shifting them from “could occur” to “reasonably expected to occur.”

Figure 33: Statewide Additional Efficiency Savings Estimated for SB 350



Source: NORESCO, 2017, and California Energy Commission, Efficiency Division, 2017.

Staff presented a conceptual approach to transforming the SB 350 analyses in this manner in internal discussions and at a DAWG meeting on October 31, 2017.[59] The approach centered on an “energy scaling factor” for programs that would be multiplied against NORESCO SB 350 estimates to generate statewide savings from individual programs. Such savings could then be included in one or more of six AAEE scenarios. This energy scaling factor is a judgmental scalar between zero and one that considers three specific criteria:

- Program Scalability Likelihood
- Potential for Double Counting
- Year-Specific Savings Pattern Credibility

59 CEC, PowerPoint presentation entitled *Role of SB 350 Energy Efficiency Savings in 2017 AAEE*, see http://www.dawg.info/sites/default/files/meetings/2017%20IEPR%20AAEE%20webinar_v4_MJ_10-27-2017.pdf

Program Scalability Likelihood is intended to assess whether the scale of the program through time matches the utility programs or codes/standards that have made up AAEE is the past. IOU program savings considered to be AAEE generally have stayed in the range of historic experience. Codes and Standards have been assumed to be implemented as called for in state or federal law. In contrast, many SB 350 programs have been assumed to scale up far beyond historic experience. While such scale-ups are possible, staff does not consider them likely. Further, many newer SB 350 programs have no assured funding commitments either from the general budget of an agency or directly funded by the legislature. When funding or other indicators of program scale are less certain, the program receive a lower energy scaling factor.

Potential for Double Counting seeks to determine whether the SB 350 savings projection has fully adjusted for double counting of savings with other programs. Despite NORESCO's attempt to avoid double counting as much as possible, a number of SB 350 programs were determined to have the potential for some overlap. Some programs appeared to double count savings from the price response or other market impacts embedded in the baseline *CED 2017 Revised* forecast. Since the purpose of AAEE is to adjust the baseline demand forecast with further savings that are incremental, downward adjustment to SB 350 savings projections is necessary for AAEE purposes. Where the potential for double counting is high, SB 350 programs receive a lower energy scaling factor.

Year-Specific Savings Pattern Credibility examines the availability of year-by-year estimates in the SB 350 savings analyses. Many programs were assessed by NORESCO using a savings analysis for 2029, with savings for intermediate years between the present and 2029 interpolated using linear or other simplistic methods. No year-by-year assessments were conducted using inputs specific to each intermediate year, because this was not believed to be needed for SB 350 purposes. Traditional AAEE requires a more rigorous year-by-year assessment since the procurement process frequently needs to assess the timing of resource additions. Those SB 350 programs assumed to have a simplistic build-out pattern would receive a lower energy scaling factor.

In general, future ratchets of standards in the SB 350 analyses beyond those included in traditional AAEE are considered a more reliable source of savings and therefore were treated differently from programs. Adjustments were applied to these ratchets in a manner consistent with treatment in the *2018 Potential Study*; these include adjustments for naturally occurring market adoptions, compliance rates, and an additional "uncertainty factor" reflecting realized versus expected savings, derived from CPUC EM&V studies. **Table 15** provides the staff energy scaling factors and standards adjustments for the additional SB 350 savings by program/standard.

After further internal and stakeholder discussion, staff settled on a conservative approach to adding in elements from the additional SB 350 savings to Scenarios 1-6 as described in **Table 9**. For Scenarios 1 and 2 (high-low and mid-low), only savings from Proposition 39 are added, with an adjustment to the simple scaling factor listed in

Table 15. Proposition 39 savings were recognized to exist in the historic period, yet these were not itemized in the baseline *CED 2017 Revised*, so an alternative approach was developed for this program. Rather than a simple multiplicative factor applied to all years, staff used the NORESCO estimates for this program to generate annual savings that follows the current statutory direction for this program. Initial Proposition 39 funding allocations not exhausted by approved applications by March 2018 will be rolled over into another round of applications for 2019 and subsequent years until funding is exhausted. Staff translated this general approach by assuming that 25 percent of nominal annual savings would occur in 2019 and 10 percent of nominal annual savings would occur in 2020. After this no further first year savings would occur, and savings from earlier years would decay gradually using the measure mix reported for 2015 — 2017 applications.

Table 15: Staff Adjustments for Additional SB 350 Savings

Program/Standards	Energy Scaling Factor	Adjustment for Standards
Local Government Ordinances	0.5	
Air Quality Management District	0	
Local Government Challenge	0.25	
Proposition 39	1	
GGRF: Low Income	0.25	
GGRF: Water-Energy Grant	0.5	
Energy Savings Program	1	
Energy Conservation Assistance Act	0.75	
PACE	0.3	
Fuel Substitution	0	
Benchmarking and Public Disclosure	0.25	
BROs	0.25	
Energy Asset Rating	0	
Smart Meter and Controls	0	
Future Ratchets: Title 24 Standards		0.68
Future Ratchets: Title 20 Standards		0.632
Future Ratchets: Federal Standards		0.632

Source: California Energy Commission, Energy Assessments Division, 2017.

For Scenario 3 (mid-mid), projected impacts of the 2019 ratchet of Title 24 for non-residential additions and alterations on existing buildings from the SB 350 analyses are also added (after applying the appropriate adjustment factor). The *2018 Potential Study* included the 2019 Title 24 ratchet, but omitted this element.[60] For Scenarios 4-5 (mid-high and low-high), projected (adjusted) savings from ratchets of Title 24 beyond 2019 from both new construction and existing buildings are added, as well as future Title 20 and federal appliance standard updates not covered in the *2018 Potential Study* but predicted to occur before 2025. Finally, for Scenario 6, projected savings are added in from the numerous additional programs shown in **Table 15**, adjusted by the appropriate scaling factors, plus projected impacts from any remaining standards ratchets (post-2025) included in the NORESCO study. **Table 16** summarizes the savings additions from the SB 350 analyses by scenario.

Table 16: Additions to AAEE From NORESCO SB 350 Analyses by Scenario

AAEE Scenario	Programs	Standards
Scenario 1 (High-Low)	Proposition 39	
Scenario 2 (Mid-Low)	Proposition 39	
Scenario 3 (Mid-Mid)	Proposition 39	2019 Title 24 non-residential additions and alterations
Scenario 4 (Mid-High)	Proposition 39	Scenario 3 plus future Title 24 ratchets for new construction and Title 20 and federal appliance standards updates before 2025
Scenario 5 (Low-High)	Proposition 39	Scenario 3 plus future Title 24 ratchets for new construction and Title 20 and federal appliance standards updates before 2025
Scenario 6 (Mid-High Plus)	Scenario 5 plus all other programs shown in **Table 17** (adjusted by scaling factors)	Scenario 5 plus post-2025 Title 20 and federal appliance standards updates

Source: California Energy Commission, Energy Assessments Division, 2017.

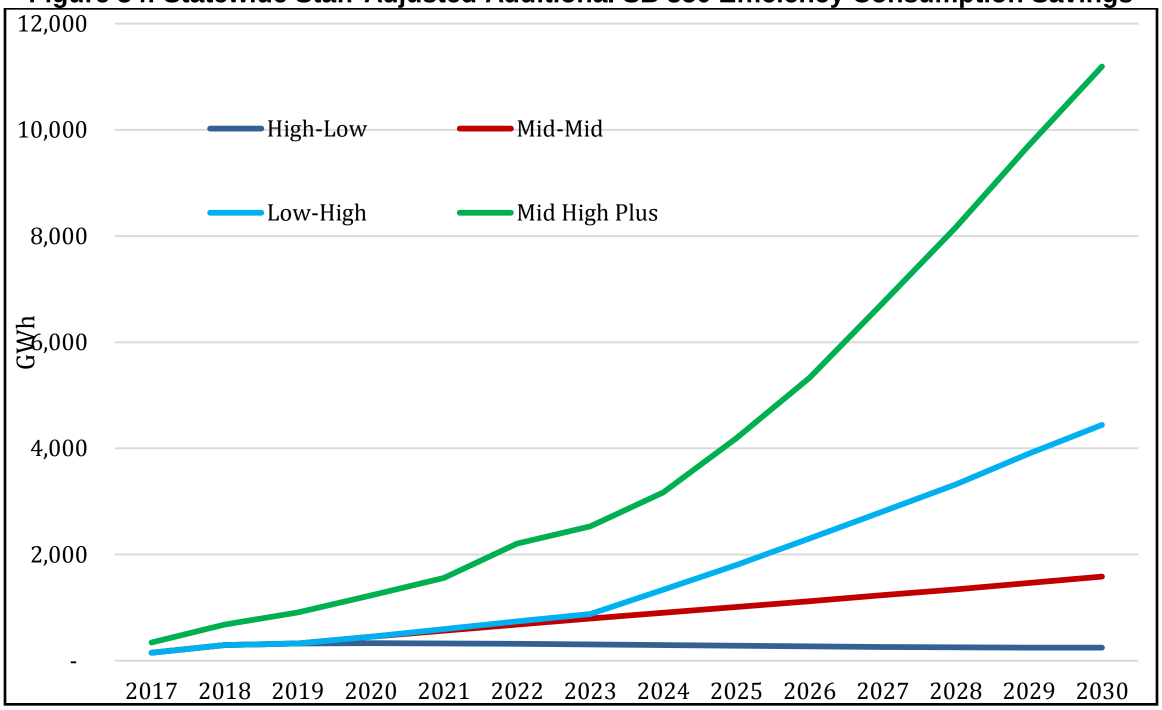
NORESCO did not attempt to estimate peak demand savings from the SB 350 initiatives. For this purpose, staff split electricity consumption savings by program or standard into sector (residential, commercial, etc.) and end-use category, using information and assumptions from NORESCO as well as staff knowledge of these initiatives. These splits are admittedly rough approximations in many cases. Staff then applied peak-to-energy

60 Navigant was not able to obtain sufficient information about this part of the 2019 Title 24 update at the time the *2018 Potential Study* was being assembled. Therefore, NORESCO included an assessment of this element.

factors from the *2018 Potential Study* to the sector/end use breakout. Rolling these calculations back up provides an estimate of total peak demand.

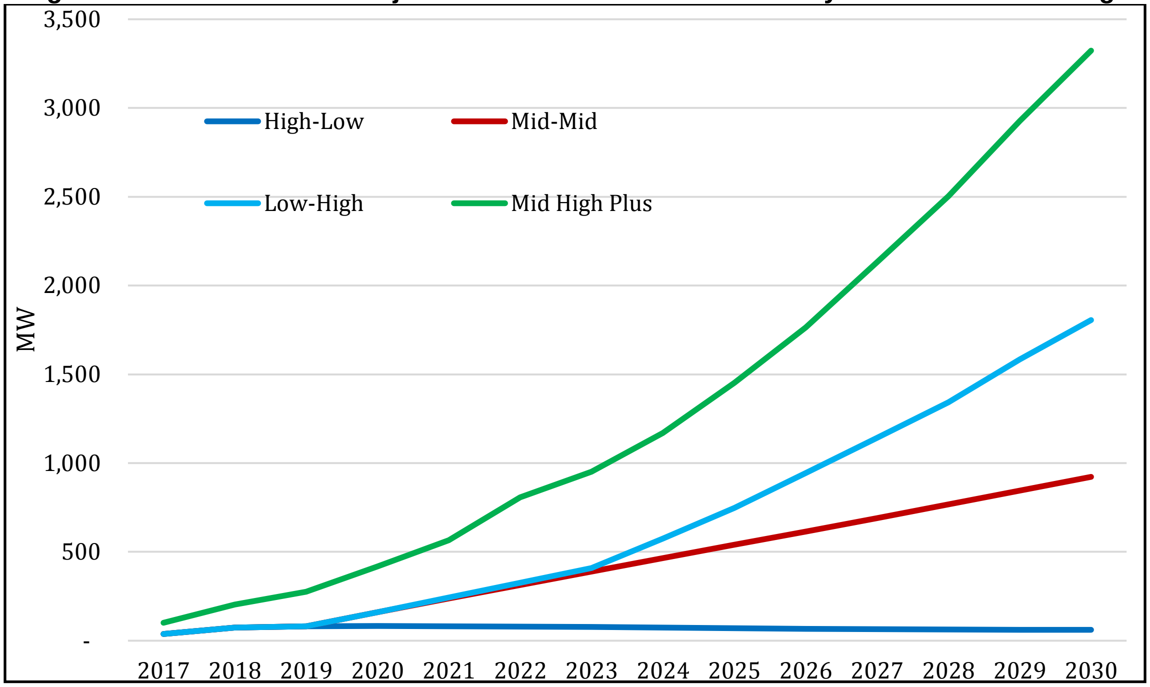
Figure 34 and **Figure 35** show the statewide totals for additional SB 350 savings by scenario for consumption and peak demand savings, respectively. Four scenarios are shown; as indicated in **Table 18**, the high-low and mid-low scenarios are identical, as are the mid-high and low-high scenarios. As with the IOU and POU traditional AAEE discussed in previous sections, the peak estimates are for reference; the IOU planning area totals are derived from the hourly model and discussed in **Chapter 4**. Savings in the high-low (and mid-low) scenarios, which include only Proposition 39 savings, decline beginning in 2019, as discussed above.

Figure 34: Statewide Staff-Adjusted Additional SB 350 Efficiency Consumption Savings



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 35: Statewide Staff-Adjusted Additional SB 350 Efficiency Peak Demand Savings



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 17 and **Table 18** show the results for the four scenarios broken out by savings from standards for consumption and (reference) peak savings, respectively. By 2030, totals range from 243 GWh in the high-low scenario to 11,195 GWh in the mid-high plus scenario. Peak savings range from 60 MW to 3,324 MW.

Table 17: SB 350 Consumption Savings by Source and Scenario (GWh), Statewide

	High-Low		Mid-Mid		Low-High		Mid-High Plus	
	Standards	Programs	Standards	Programs	Standards	Programs	Standards	Programs
2017	-	149	-	149	-	149	-	340
2018	-	292	-	292	-	292	-	683
2019	-	323	-	323	-	323	-	910
2020	-	332	122	332	122	332	122	1,105
2021	-	322	243	322	272	322	272	1,286
2022	-	317	365	317	422	317	422	1,786
2023	-	307	487	307	572	307	572	1,959
2024	-	297	608	297	1,039	297	1,039	2,131
2025	-	282	730	282	1,519	282	1,895	2,292
2026	-	268	852	268	2,034	268	2,908	2,419
2027	-	259	974	259	2,550	259	4,153	2,581
2028	-	251	1,095	251	3,068	251	5,412	2,747
2029	-	248	1,217	248	3,651	248	6,789	2,918
2030	-	243	1,339	243	4,201	243	8,108	3,087

Source: California Energy Commission, Energy Assessments Division, 2017.

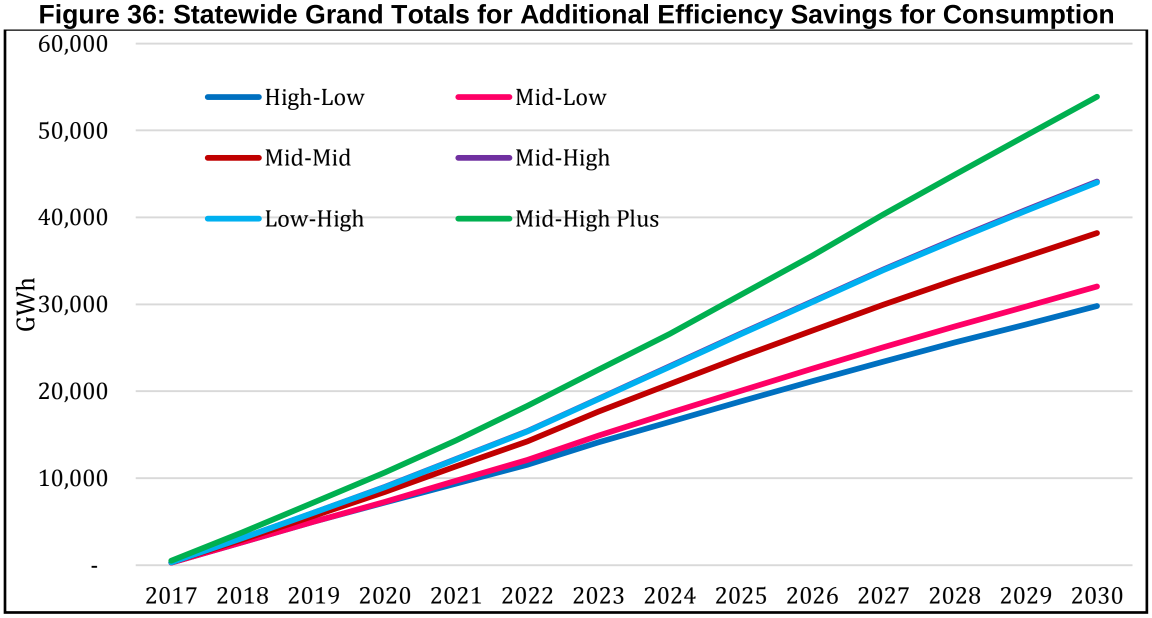
Table 18: SB 350 Peak Demand Savings by Source and Scenario (MW), Statewide

	High-Low		Mid-Mid		Low-High		Mid-High Plus	
	Standards	Programs	Standards	Programs	Standards	Programs	Standards	Programs
2017	-	37	-	37	-	37	-	101
2018	-	73	-	73	-	73	-	203
2019	-	80	-	80	-	80	-	276
2020	-	82	78	82	78	82	78	340
2021	-	80	157	80	163	80	163	402
2022	-	79	235	79	248	79	248	560
2023	-	76	313	76	332	76	332	619
2024	-	74	391	74	501	74	492	677
2025	-	70	470	70	678	70	719	732
2026	-	67	548	67	877	67	988	777
2027	-	64	626	64	1,078	64	1,300	831
2028	-	62	705	62	1,279	62	1,615	888
2029	-	62	783	62	1,523	62	1,981	945
2030	-	60	861	60	1,745	60	2,322	1,002

Source: California Energy Commission, Energy Assessments Division, 2017.

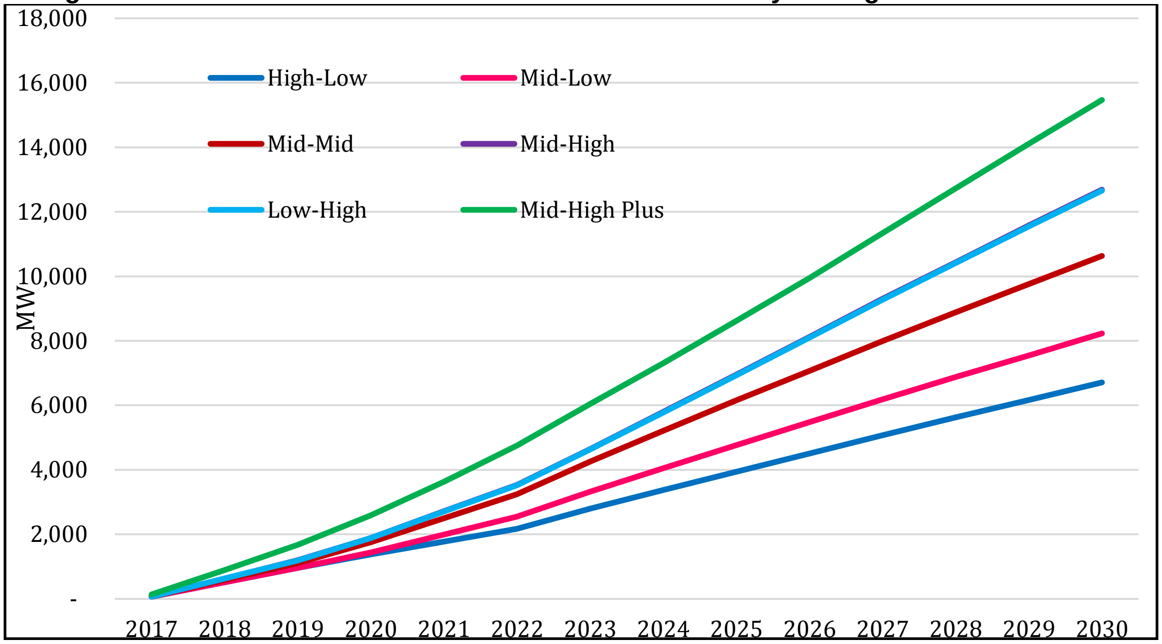
Finally, **Figure 36** and **Figure 37** show additional SB 350 savings combined with traditional IOU and POU AAEE for consumption and (reference) peak demand, respectively, to provide grand totals for statewide additional efficiency. The mid-high and low-high scenarios for both consumption and peak savings are very close together but not identical. The mid-mid scenario consumption savings reach about 38,000 GWh by 2030, while the mid-high plus scenario is almost 54,000 GWh. For peak demand, the totals are around 10,600 MW and 15,400 in 2030 for these two scenarios.

Figure 36: Statewide Grand Totals for Additional Efficiency Savings for Consumption



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 37: Statewide Grand Totals for Additional Efficiency Savings for Peak Demand



Source: California Energy Commission, Energy Assessments Division, 2017.

Additional Achievable Photovoltaic Adoption

The 2019 Title 24 building standards update will include PV system requirements for new homes that, when paired with efficiency improvements, are intended to meet Zero Net Energy goals for new residential homes, starting in 2020. Given that 2019 Title 24 on the efficiency side is part of AAEE, consistency requires that additional adoptions of behind-the-meter PV due to these regulations also be separated from the baseline forecast.

Within the baseline forecast, a certain percentage of new single-family homes adopt PV systems. AAPV adoptions are then the difference between adoptions for new homes per the Title 24 regulations and new home adoptions already in the baseline forecast, from 2020 — 2030.

Three scenarios were constructed to be paired with the baseline demand cases, as follows:

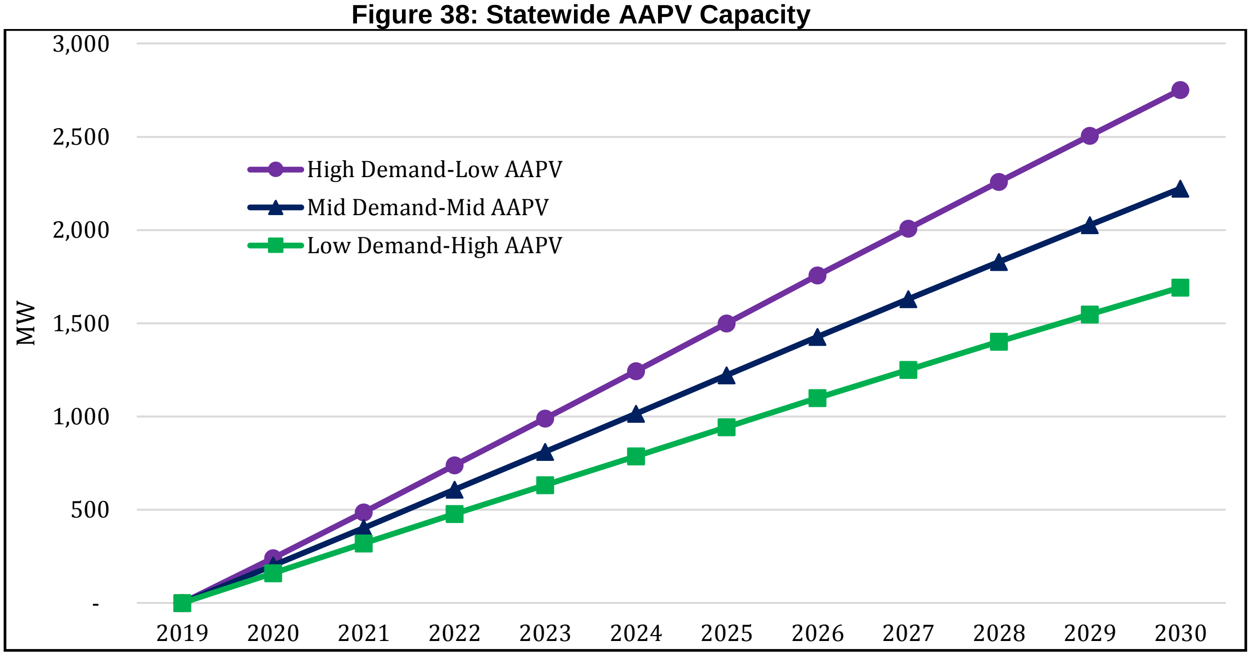
- Scenario 1: High Demand-Low AAPV (high-low)
- Scenario 2: Mid Demand-Mid AAPV (mid-mid)
- Scenario 3: Low Demand-High AAPV (low-high)

Based on stakeholder comments and internal discussions with the Energy Commission's Energy Efficiency division, staff assumed that Title 24 regulations will induce 70 percent of single family homes to be built with a PV system after 2019 in the high-low scenario and 90 percent in the low-high scenario, with the average of the additions between these two scenarios (about 80 percent) making up the mid-mid scenario. Aside from these new home requirements, the PV scenarios are identical to those used in the baseline projections; for example, low AAPV assumes lower electricity rates and the more restrictive adoption curve, as discussed in **Chapter 1**.

Figure 38 shows the additions to statewide PV capacity for each of the scenarios. The seeming reversal in order (low AAPV has more additions than high AAPV) is due to the difference in new homes subject to the regulations given adoptions in the baseline forecast. In the high demand-low AAPV scenario, a greater percentage of new homes are projected to adopt PV in the baseline, leaving less homes available for the regulations. By 2030, AAPV additions increase capacity by 24 percent, 12 percent, and six percent over the baseline in Scenarios 1-3, respectively. Annual electricity consumption served by PV increases by 4,800 GWh, 3,900 GWh, and 3,000 GWh by 2030 in Scenarios 1-3, respectively.[61]

For the managed forecasts, mid demand-mid AAPV would be paired with the mid demand-mid AAEE scenario for system planning. For the mid demand-low AAEE scenario used for localized planning, staff has proposed to pair a mid-demand-low AAPV scenario identical to mid demand-mid AAPV except that the compliance rate is reduced from 80 percent to 70 percent. This means that the new scenario is calculated by multiplying mid demand-mid AAPV additions by 7/8.

Figure 38: Statewide AAPV Capacity



Source: California Energy Commission, Energy Assessments Division, 2017.

61 As with AAEE, peak demand impacts depend on the amount of peak shift and are provided by planning area in **Chapter 4**.

CHAPTER 3:
Hourly Load Forecasts

Introduction

The increased importance of renewable generation requires an understanding of hourly demand for electricity given that these resources may not be available at certain times of the day. Hourly demand analysis becomes even more critical because of the growing importance of demand modifiers such as PV and light-duty EVs, since these factors may affect the hour at which peak utility demand occurs, as well as the magnitude and timing of the "ramp up" period to peak.

Energy Commission demand forecasts traditionally produce annual projections for electricity consumption, utility sales, and utility peak demand. To make the forecast more useful to resource planners' staff set out to develop an hourly load forecasting model that incorporates the effect of the most important demand modifiers. For *CED 2017 Revised*, staff has implemented models for the three IOU planning areas at the system level. This is a first step; proper assessment of hourly loads can be improved through further disaggregation of hourly loads into sector demand and smaller geographic regions. The extent to which future forecasts can incorporate more disaggregate versions of an hourly model will depend on the availability of appropriate load data. Complete hourly results developed in this effort, including demand modifiers, are posted with this report.[62]

Hourly Load Forecasting Model

Model Structure

The hourly load forecasting model used in CED 2017 Revised employs an econometric framework to model hourly load using California ISO Energy Management System (EMS) hourly data and hourly PV generation data simulated from the CSI program. These two components together constitute a "consumption" load, which is the starting point for measuring the impact of demand modifiers.[63] The California ISO provides EMS data back to 2006, thus the sample period used for model estimation was 2006 — 2016. The dependent variable (the variable to be estimated) was specified as hourly consumption load divided by annual average hourly consumption load, or the "load ratio."[64] In this manner, growth in overall load from year to year is exogenous, in the sense that annual

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62 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

63 There is of course load met with other self-generation aside from PV, but staff did not have suitable hourly profiles for non-PV self-generation, and made the simplifying assumption that such generation is fairly flat over the course of a day and therefore its omission would not significantly affect predicted hourly utility load.

64 This specification follows from the work of Rob J. Hyndman and Shu Fan (2010), "Density Forecasting for Long-Term Peak Electricity Demand," *IEEE Transactions on Power Systems* 25(2), 1142-1153.

average hourly consumption load derives directly from the traditional annual forecast. This means that economic, demographic, and other factors affecting annual load do not need to be explicitly accounted for in the hourly model. In other words, these load growth factors drive the annual average hourly load but not the ratios between hourly load and annual average hourly load.

More formally, the model is specified as

$$y_{t,p} = y^*_{t,p} * \overline{y_i},$$

where, in a given year, $y_{t,p}$ is hourly consumption load in day t and hour p, $y^*_{t,p}$ is the load ratio for day t and hour p, and $\overline{y_i}$ is the annual average hourly load in year i. The variable to be estimated through econometric analysis is $y^*_{t,p}$, the load ratio. Regressions were done for each hour for each planning area, a total of 72 regressions, in the form

$$\log\left(y^*_{t,p,i}\right) = h(t, i) + f\left(WT_{t,p,i}, WCC_{t,p,i}, WDP_{t,p,i}\right) + e_{t,p,i},$$

where *h* represents a function for calendar effects (day of the week, month, holidays) and *f* represents a function for weather variables, which includes weighted hourly temperatures (*WT*) for each IOU planning area, weighted hourly cloud cover[65] (*WCC*), and weighted hourly dew point (*WDP*), and *e* represents model error. Weighted weather variables for each planning area were developed using weather stations representing individual forecast zones within the planning area.[66] Calendar effects are modeled using separate dummy coefficients for each day of the week, each month, and for holidays. Weighted temperatures are incorporated in various forms, including current hourly, lagged hourly, minimum over the last 24 hours, average over the last 24 hours, previous day's average, and average two days previous. Dew point is meant to provide a level of relative humidity, together with temperature and cloud cover. Each of the 72 regressions were estimated accounting for autocorrelation (correlation across time) and for unaccounted differences across years.[67] The explanatory power of the model, in terms of R^2, depended on the hour for estimation[68] and varied from around 80 percent to over 95 percent. Regression results, including good-of-fit tests, are available upon request.

Forecasting Weather-Normalized Consumption Loads

Forecasted hourly loads must reflect historically normalized weather, given the impossibility of predicting hourly weather into the future. For this purpose, staff focused on the distribution of the hourly load ratios under a variety of conditions, as opposed to attempting to develop "average" weather conditions for each hour.[69]

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65 Expressed as a percentage for a given hour.

66 Weights were estimated using coefficients from regressions of load on weather station temperatures.

67 Using a dummy variable for each year.

68 For example, the R2 was lower in the early morning hours, when temperature has less impact on load.

69 This would require a process to simultaneously normalize temperatures, cloud cover, and dew point.

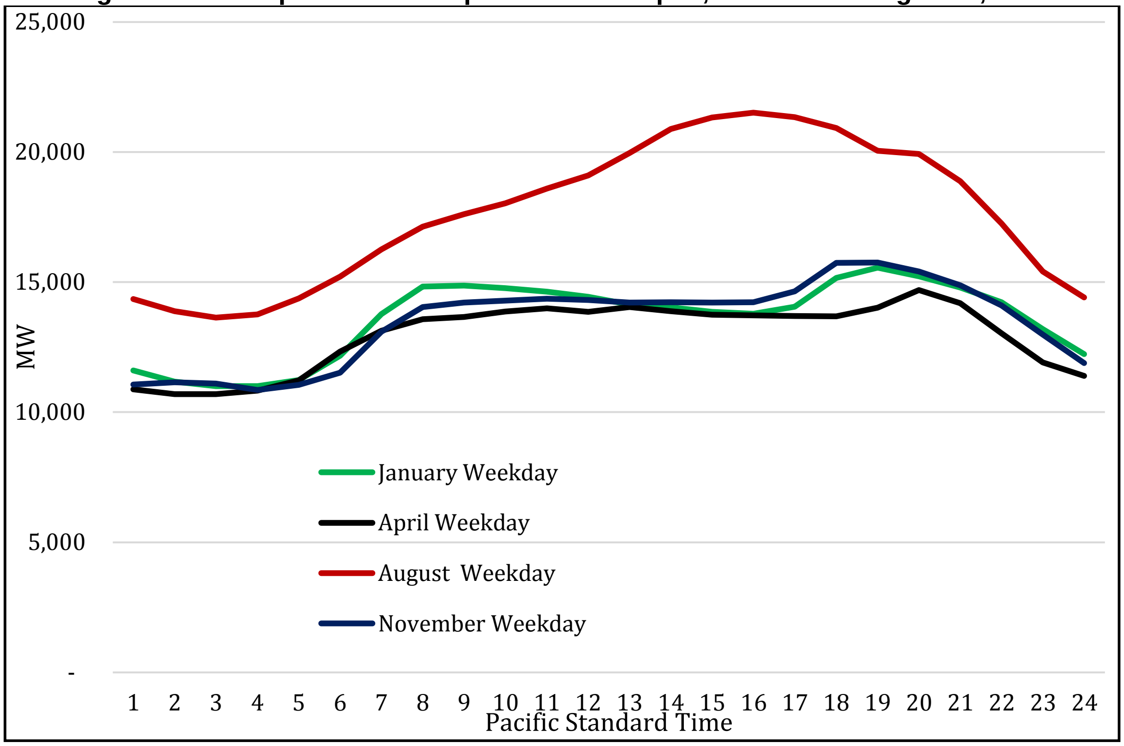
The distribution for load ratios for each planning area was created by using the regression model results to simulate the ratios for all seventeen years (2000 — 2016) where historical hourly weather data was available and varying the day of the week in which each year started to account for differing calendar effects. This meant a total of 17×7=119 sets of 8760 (365×24) simulated hourly load ratios. Next, the load ratios for each simulation were ranked highest to lowest. The 119 maximum hourly load ratios from each simulation formed a distribution for annual peak, and the median of this distribution served as the weather-normalized consumption peak hourly ratio. The median of the second highest load ratio in each simulation became the weather-normalized second highest load ratio and so on, all the way down to the lowest load ratio in each simulation, providing a ranked set of 8760 weather-normalized load ratios.

These ranked, weather-normalized load ratios then had to be assigned to a specific day and hour. For this purpose, staff chose an historical year for each IOU planning area that was as close as possible in terms of annual cooling and heating degree days to a 30-year average for these variables. The advantage of using an historical year for assignment is that actual weather correlations that occur within a year (day to day, week to week) are preserved. The year 2009 was selected for SCE and SDG&E and 2012 for PG&E. The weather-normalized load ratios were then assigned to a day and hour based on ranking. For example, the actual consumption peak in 2009 for SCE occurred on September 3, 3-4 pm, so the weather-normalized peak load ratio from the simulations was assigned this date/hour. The second highest weather-normalized load ratio was assigned to September 3, 4-5 pm, which had the second highest actual hourly load in 2009, and so on for all 8760 hours.

Given the 8760 normalized load ratios for each IOU planning area, hourly loads ere forecast by applying annual forecasts of consumption load (minus non-PV self-generation) converted to annual average hourly load to the ratios. For each forecast year, the ratios are rearranged to preserve the weekday/weekend/holiday relationship using the actual calendar in that year. These loads are then adjusted by the demand modifiers (including PV) to give hourly demand for load to be served by utilities.

Figure 39 shows an example of projected hourly consumption loads, using 2030 for the PG&E planning area in the mid demand case, before any adjustment for the demand modifiers. A weekday was randomly chosen for four different months. The load shapes are what would be expected: the highest loads in August due to cooling load, with the peak hour occurring in the late afternoon; the flattest loads in April with the peak hour driven by lighting; the peak hour in November and January happening earlier than April because of lighting needs earlier in the day and some heating load.

Figure 39: Example of Consumption Load Shapes, PG&E Planning Area, 2030



Source: California Energy Commission, Energy Assessments Division, 2017.

Hourly Demand Modifiers

PV Generation

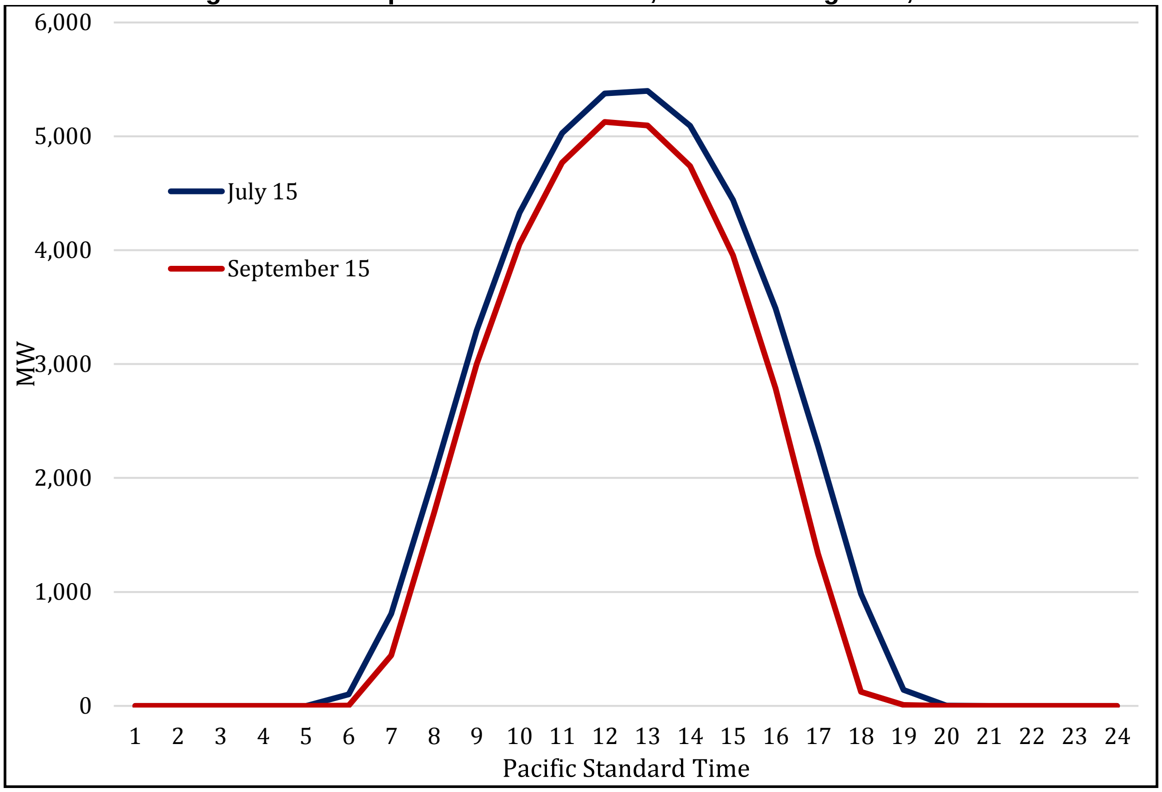
Hourly load profiles for PV generation were developed based on analysis of California Solar Initiative data.[70] Simulated hourly profiles for each IOU were averaged over a four-year period (2009 — 2012) to calculate a preliminary average annual hourly profile. However, significant daily variation remained resulting from particular weather conditions in a given year. For example, a given date may have been cloudy for two of the four years, so the profile would show a large drop-off in generation for that day. Therefore, staff smoothed the series further by averaging over a seven-day period.

Staff then took the annual PV additions from the forecast period and converted them to monthly additions by applying a uniform monthly installation rate. Next, staff applied the PV generation profiles to estimate hourly generation starting with the month of installation to the end of the forecast period. A similar approach was used to estimate hourly generation from PV systems installed in the historical period except that the actual installation month was used. Aggregating generation from projected installations in the forecast period and actual installations from the historical period produces an estimate of total hourly generation.

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

Figure 40 shows an example of resulting PV generation by hour, using two summer days in 2030 for the SCE planning area. The July day, with more direct sunlight, yields more generation in each non-zero hour and shows generation for more hours given a longer day. The figure shows the rapid drop-off in generation in the afternoon, particularly after 5 pm. This steep afternoon decline is a primary factor in utility peaks shifting to a later hour.

Figure 40: Example of PV Generation, SCE Planning Area, 2030



Source: California Energy Commission, Energy Assessments Division, 2017.

EV Hourly Loads

Hourly loads for light-duty EVs were developed by applying charging profiles to EV stock and consumption by vehicle class from the TEFU's EV forecast.[71] The charging profiles were constructed by the Lawrence Berkeley National Laboratory (LBNL) and a full description of method is available in a forthcoming report.[72] The software created to simulate EV profiles is also available online.[73] The LBNL team assumed travel behavior based on 2009 National Household Travel Survey data for California drivers.[74]

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71 Details on the EV forecasts are available in a transportation report here: http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-05/TN221893_20171204T085928_Transportation_Energy_Demand_Forecast_20182030.pdf.

72 To be posted with the other forecasting materials when available.

73 https://github.com/Samveg/V2G-Sim-beta.

74 Survey data available at http://nhts.ornl.gov/download.shtml#2009.

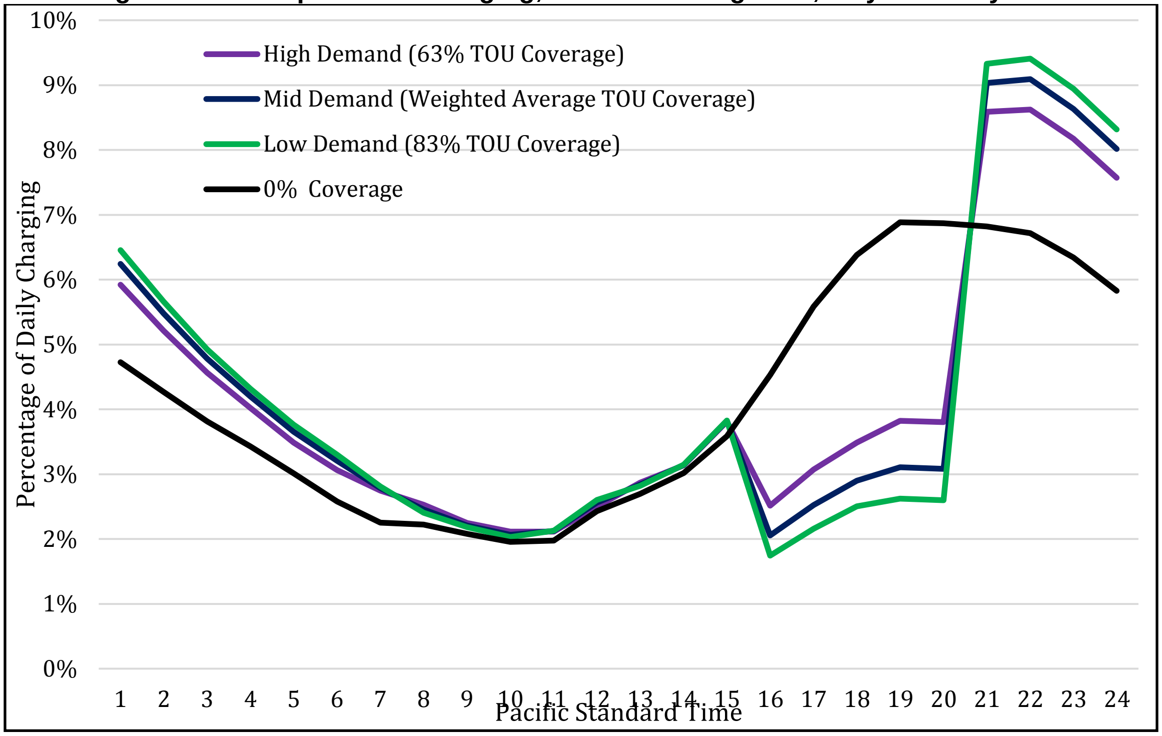
LBNL modeled each vehicle as a series of daily trips (including parking) in each forecast zone based on travel diaries from the National Household Travel Survey. Temperature data for each zone determined the amount of air conditioning used per vehicle (which reduces vehicle range). Battery consumption is then a function of temperature, trip distance, trip duration, and vehicle efficiency. Parking "events" are assigned a probability of charging based on need and charging infrastructure, which varies based on forecast zone. The amount of charging while parking determines the demand for home charging.

The LBNL team incorporated widespread residential TOU pricing beginning in 2020 within modeled scenarios based on staff assumptions (see next section). For this purpose, the team introduced a "willingness to pay" based on a vehicle's state of charge. A defined price threshold determined whether a vehicle would charge in a particular hour. To be consistent with staff work, the team assumed two levels of TOU coverage: 63 percent and 83 percent. The lower coverage was used for the high demand hourly EV, the higher coverage for low demand, and a weighted average of the two for the mid demand case. LBNL also provided a scenario with zero TOU coverage.

Figure 41 shows an example of resulting EV load shapes using a July weekday (non-holiday) in 2030 for the PG&E planning area. For comparison purposes, load is given as a percentage of total daily load since the load projections by demand case differ in absolute magnitude with the number of vehicles. The impact of TOU peak pricing from 4-9 pm (see next section) is evident in the figure, with a significant amount of charging shifting to late evening and early morning.

The planning areas where residential TOU is expected to become significant starting in 2020 were assigned high, mid, and low TOU coverage, as in **Figure 41**. These include the three IOU planning areas as well as NCNC. For the remaining planning areas, the EV load shapes corresponding to 0 percent coverage were used in all three scenarios.

Figure 41: Example of EV Charging, PG&E Planning Area, July Weekday 2030



Source: California Energy Commission, Energy Assessments Division, 2017.

Residential TOU Pricing

Beginning in 2019, SMUD and the three IOUs and will begin to transition residential customers to a TOU rate with the choice to opt out to a standard flat or tiered rate. While utilities already offer residential TOU rates, enrollment has been very low. *CED 2017 Revised* incorporates the estimated effects of the change to an opt-out regime, under which a much larger percent of customers are expected to experience higher prices during peak periods and hence an incentive to reduce or shift load. This section summarizes the methodology used to produce hourly load impacts from residential TOU pricing.

Staff developed a constant elasticity of substitution (CES) demand model[75] to estimate customer response to a time-varying rate compared to the flat rates used in the *CED 2017 Revised* residential model. The CES model is applied to each day of the year, using the applicable rates, pricing periods, temperatures, and reference loads for the day. Key assumptions for this analysis include the rate design of the default rate, price responsiveness assumptions, and the number of households persisting on a TOU rate.

Residential hourly loads were projected based on 2015 hourly load profiles submitted by each utility for the 2017 IEPR and calibrated to the *CED 2017 Revised* residential

75 Constant elasticity of substitution assumes a constant percentage change in demand for a given percentage change in price.

consumption forecast, including the impacts of AAEE. Time periods are modeled based on the rate designs approved in the CPUC Resolutions adopting IOU default pilot rate designs, and the rate design adopted by the SMUD governing board.[76] These rates, which will be tested in 2018 pilot studies, have a peak period of 4-9 PM for the IOUs and 5-8 PM for SMUD, year-round. The SMUD rate will also have a summer mid-peak rate from 12PM-5PM, and SCE is testing three-period rates in the winter. Staff modeled the proposed SCE rate with a winter "super" off-peak period of 8AM- 4PM. As the *CED 2017 Revised* forecast for SMUD does not incorporate peak shift, meaning that the peak hour is assumed to continue at the traditional time (4-5 pm), TOU does not have a significant impact on peak, although it does affect hourly EV load, as discussed in the previous section.

Price elasticities were developed using the CES model of price elasticity estimated as part of the Statewide Pricing Pilot.[77] This study estimated customer response to time-varying rates as a function of temperature, central air conditioning saturation, day-type, and other customer characteristics. Staff used these estimated coefficients with daily historical weather statistics and projected air conditioning saturations to calculate daily and substitution price elasticities by forecast zone.

To estimate load impacts, the price elasticities were applied to usage per hour statistics to calculate change in usage by TOU period. Initial results were compared to evaluation results of the 2017 IOU opt-in TOU pilot study.[78] In this study, load impacts were often observed to be similar across rates with different peak to off-peak price ratios. To produce results consistent with pilot results, staff used a higher price ratio than the sometimes relatively low differentials proposed for the IOU rates. Using the actual, relatively low, price ratios to estimate load impacts tends to under predict compared to observed results.

The 2017 IOU pilot study load impacts are likely to be more reflective of an opt-in as opposed to default (opt-out) population. The evaluation of the SMUD Smart Pricing Options Pilot found that the average per household impact of customers defaulted to TOU rates was significantly lower (around 1/3) than of customers who opted in to a TOU rate, reflecting unaware or unengaged customers among the defaulted population.[79] To account for this "default effect" in the staff forecast, the initial per-household impacts are reduced, as shown in **Table 19**.

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76 CPUC Resolutions E-4846, E-4848, and E-4847; https://www.smud.org/assets/documents/pdf/board-packet-06-15-2017.pdf.

77 Impact Evaluation of the Statewide Pricing Pilot, Charles River & Associates, March 16 2005, http://archive.energy.ca.gov/demandresponse/documents/index.html#group3.

78 California Statewide Opt-in Time-of-Use Pricing Pilot Second Interim Evaluation, November 1, 2017, Nexant and *Research Into Action*. http://www.cpuc.ca.gov/General.aspx?id=12154.

79 SmartPricing Options Final Evaluation, September 5, 2014, George, Stephen S., Jennifer Potter and Lupe Jimenez, https://www.smartgrid.gov/files/SMUD_SmartPricingOptionPilotEvaluationFinalCombo11_5_2014.pdf.

Finally, staff projected the number of participating households. Under governing statute and per CPUC decision, many IOU customers will be exempt from the default transition, although they may choose to enroll. Customers on medical baseline rates or requiring third-party notification are exempt. Customers with the less than 12 months of interval meter data are exempt from the initial default transition. The CPUC has decided to exclude low income customers[80] from the default pilots, and they are likely to continue to be excluded. Staff used exempt population estimates prepared by the IOUs with staff household projections to estimate the number of eligible households in each scenario. In all scenarios, the opt-out rate of eligible households is assumed to be 10 percent for IOUS and four percent for SMUD.

Applying the participating household projections to the adjusted per-household load impacts produces average aggregate impacts by time period. Finally, the percentage impact of the average aggregate impacts by time period was applied to the original projected hourly loads to produce scenarios of hourly load impacts.

Table 19: Key Assumptions for Residential TOU Analysis

	Mid Demand Case	High Demand Case	Low Demand Case
Peak-to-Off-peak rate differential	Constant	Constant	Increasing
Default Effect Adjustment	35%	45%	25%
Participation	Mid Case Household Projections; Low Income Excluded	High Case Household Projections; Low Income Excluded	Low Case Household Projections; Low Income Included
Residential Consumption Forecast	Mid Demand Case	High Demand Case	Low Demand Case
AAEE	Scenario 3 (Mid-Mid)	Scenario 1 (High-Low)	Scenario 5 (Low-High)

Source: California Energy Commission, Energy Assessments Division, 2017.

To give a sense of the magnitudes of projected residential TOU impacts, **Table 20** shows the average hourly impact (MW reduction) during the peak periods on a weekday in mid-August for the three IOUs and SMUD.

80 Defined by income levels given household size.

Table 20: TOU Average Hourly Load Reduction (MW) During Peak Period, Mid-August Weekday

Utility	Year	High Demand	Mid Demand	Low Demand
PG&E	2020	66	79	133
4-9 pm	2030	82	83	158
SCE	2020	95	110	162
4-9 pm	2030	121	130	246
SDG&E	2020	15	18	20
4-9 pm	2030	20	22	27
SMUD	2020	36	41	47
5-8 pm	2030	45	48	61

Source: California Energy Commission, Energy Assessments Division, 2017.

Hourly AAEE

The demand modifiers discussed previously in this chapter applied to hourly consumption load provide baseline hourly utility loads. For *managed* hourly utility loads for the IOU planning areas, hourly AAEE and AAPV impacts must also be considered. The adjustment for AAPV is based on the same generation profiles used for PV impacts in the baseline forecast. To translate AAEE savings into hourly projections, including the additional savings developed in support of SB 350, staff, with the assistance of Navigant Consulting, used a similar methodology to that used for *CED 2015* and *CEDU 2016*.[81] In this approach, annual energy savings at the sector/use category level are allocated to hourly savings using profiles that represent the share of annual savings in each hour.

Due the evolving nature of the AAEE scenarios and the scope of customer sectors and energy efficiency measures within them, a larger proportion of electric energy savings are now in use categories that had not been prominent in earlier IEPR cycles. For *CED 2015* and *CEDU 2016*, there were 15 specifically designated sector/use categories and four "other" categories for miscellaneous groupings. For *CED 2017 Revised*, there are 19 designated sector/use categories and one profile representing residual savings in each of four customer sectors, for a total of 23 sector/use category profiles for each IOU service area. **Table 21** shows the use categories by sector.

81 CEC, *Translating Aggregate Energy Efficiency Savings Projections into Hourly System Impacts*, CEC Report Number CEC-200-2016-007, June 2016. See http://www.energy.ca.gov/2016publications/CEC-200-2016-007/

Table 21: Sector/Use Categories Modeled for Hourly Efficiency Savings

Sector	End Use Categories	
Agricultural	Machine Drive	Whole Building
	Process Refrigeration	Other (Residual)
Commercial	Appliance-Plug-in	Water Heating
	Refrigeration	Whole Building
	HVAC	Other (Residual)
	Lighting	
Industrial: Manufacturing	Lighting	Whole Building
	Machine Drive	Other (Residual)
Industrial: Resource	Oil and Gas Extraction	
Residential	Appliance-Plug-in	Whole Building (Equipment)
	HVAC	Whole Building (Behavioral)
	Lighting	Other (Residual)
Street Lighting	Street Lighting	

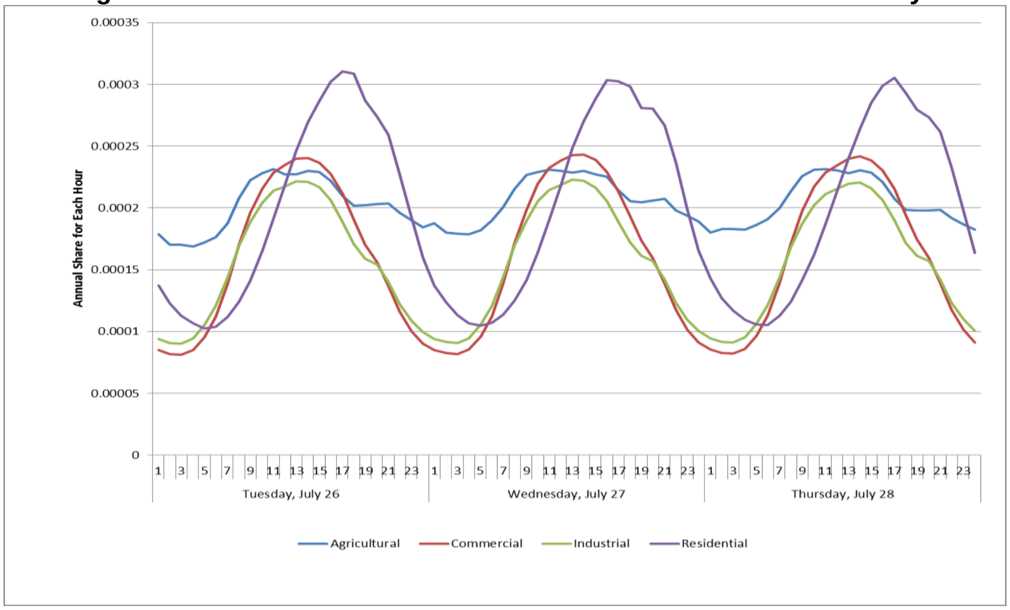
Source: California Energy Commission, Energy Assessments Division, 2017.

The *CED 2015* and *CEDU 2016* versions of hourly load analysis start with simulated end use savings loads that follow the 2013 calendar, based on the origin of the profile data. For *CED 2017 Revised*, Navigant used actual 2016 IOU data, so the profiles were updated to use the 2016 calendar. For forecast years, staff adjusted the calendar to match the appropriate year so that, for example, weekend and holiday profiles were assigned to the proper days.

In addition to developing AAEE hourly savings for the IOU service territories, staff undertook to develop sector/use category savings projections for POUs within the IOU planning areas. Unfortunately, the contract resources expected to assist with this effort could not be made available during the time interval required to develop the hourly profiles. Ultimately, approximations were developed by using hourly profiles from IOU service territories for POUs embedded in the same planning area.

Each of the named sector/use category profiles has a shape that closely matches the total load profile for that sector. This is expected, since energy efficiency measures can only induce aggregate load reductions in hours when there is load in the first place. Some specialized measures may have profiles that differ substantially from the underlying customer sector load shape, but these are limited in scope. **Figure 42** provides an illustration of the basic shapes of the customer sector load profiles using selected summer days for SCE as an example. These profiles are used in the analysis for energy savings from energy efficiency measures that have aggregate savings too small to warrant being modeled individually. Although there are basic similarities among the three days that are plotted, there are differences among them that can be traced back to use of actual data for year 2016 to develop these profiles. In contrast to other hourly modeling results, these daily differences have been preserved to allow investigation of the variability of results. No smoothing or averaging has been implemented. Full results at the sector/use category level are available from staff upon request.

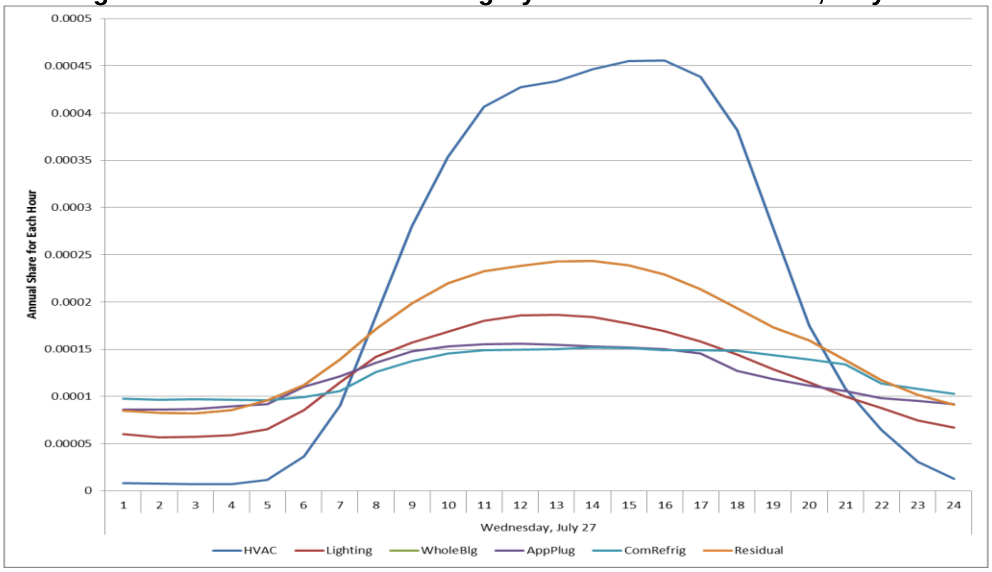
Figure 42: Sectoral Load Profiles for SCE for Selected Summer Days



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 43 provides a sample set of hourly profiles for the use-categories that make up the commercial sector as modeled for SCE. Not unexpectedly, the HVAC use-category has savings more concentrated during typical hours of operation of commercial buildings than the other end-uses, especially since the data in **Figure 43** are for a hot day, coinciding with the overall California ISO system peak in 2016.

Figure 43: Commercial Use Category Load Profiles for SCE, July 27



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 22 reports the maximum hourly load savings for each of the three IOU service territories and the two groupings of smaller POUs within the California ISO balancing authority area for the mid-mid AAEE scenario. These maximum values do not necessarily occur at the peak hour of either the baseline or managed demand forecast; rather, they are an input into the process of determining how the peak hour shifts across the five managed demand forecast scenarios and through time within a given demand forecast scenario. Complete hourly results for AAEE for these geographies are included with the hourly forecasting results posted with this report.[82] Note that results begin in 2018; AAEE peak savings are incorporated incremental to 2017, since the hourly load model is calibrated to actual historical 2017 peaks.

Table 22: Maximum Hourly Efficiency Load Savings, Mid-Mid Scenario

	PG&E Service Territory	POUs Within PG&E Planning Area	SCE Service Territory	POUs Within SCE Service Territory	SDG&E
2018	169	21	177	26	36
2019	318	39	331	51	69
2020	473	60	502	77	105
2021	639	83	688	105	144
2022	801	105	873	131	183
2023	1043	141	1147	166	244
2024	1268	174	1406	198	302
2025	1487	205	1661	228	360
2026	1700	235	1911	257	418
2027	1909	263	2164	284	476
2028	2113	290	2416	309	535
2029	2306	316	2665	333	594
2030	2499	341	2913	357	653
NOTE: Numbers do not include line losses.					

Source: California Energy Commission, Energy Assessments Division, 2017.

82 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

CHAPTER 4: Electricity and Natural Gas Planning Area Results

This chapter summarizes forecast results for the five major electricity planning areas in California: PG&E (electricity and natural gas), SCE, SDG&E, NCNC, and LADWP. In addition, results are described for the three major natural gas planning areas: PG&E, SoCal Gas, and SDG&E. Comprehensive results for the planning areas, including economic/demographic assumptions, rates, self-generation and PV impacts, and EV results are available electronically as a set of forms posted with this report.[83] Results are provided for both the baseline and managed forecasts, which incorporate AAEE and AAPV.

PG&E Electricity Planning Area

The PG&E electricity planning area includes:

- PG&E bundled retail customers.
- Customers served by energy service providers and community choice aggregators using the PG&E distribution system to deliver electricity to end users.
- Customers of POUs and other providers in the PG&E TAC area (**Table 4**).
- Key factors incorporated in the forecast include the following:
- Projected population growth averages 0.95 percent per year over 2016-2030, higher than the average for the state as a whole (0.81 percent). Projected growth in the number of households in the mid case averages 1.03 percent per year, also higher than the state average (0.94 percent).
- Personal income per capita growth averages 1.90 percent per year from 2016-2030, slightly higher than the state average (1.88 percent).
- EV electricity consumption by 2030 is projected to be about 6,500 GWh, 6,000 GWh, and 4,500 GWh in the high, mid, and low demand cases, respectively.
- Additional electrification adds 490 GWh, 260 GWh, and 75 GWh to consumption in the high, mid, and low cases, respectively, by 2030.
- Projected behind-the-meter PV installed capacity for the baseline forecast reaches 5,600 MW, 8,700 MW and 11,800 MW in the high, mid, and low demand cases, respectively, by 2030.

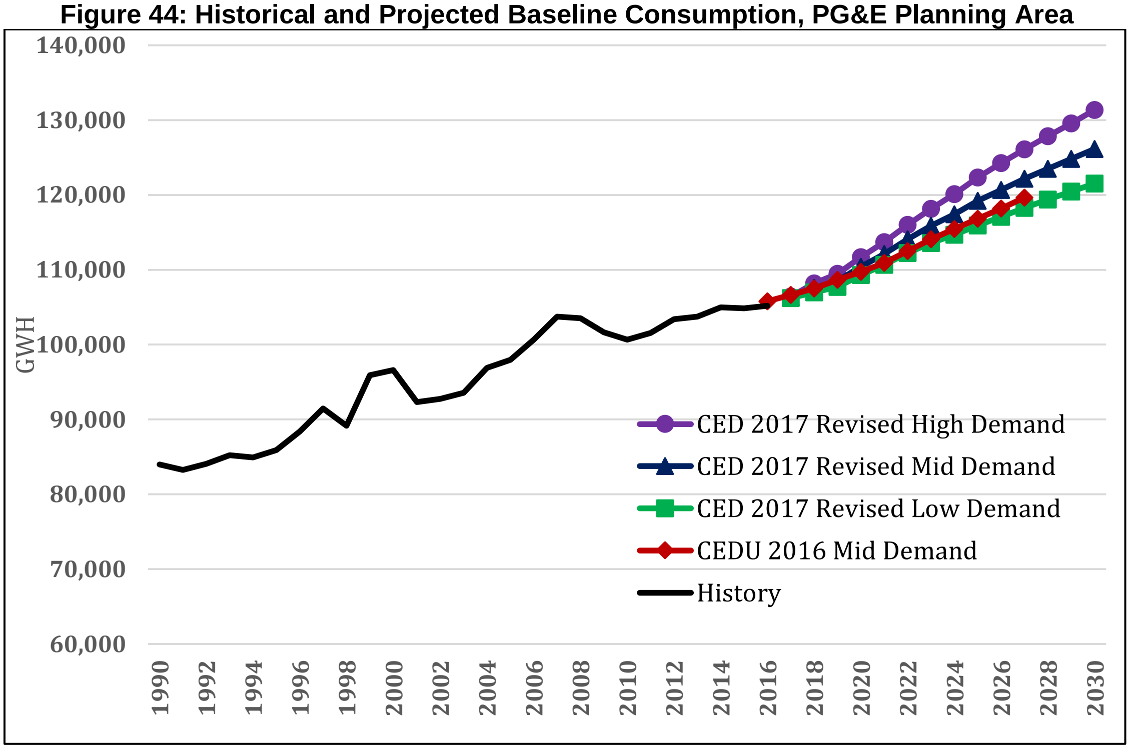
83 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

- Incremental climate change impacts are projected to add 475 GWh and 280 GWh to annual consumption and 620 MW and 270 MW to peak demand by 2030 in the high and mid demand cases, respectively.
- Traditional AAEE, additional SB 350 savings, and AAPV reduce mid demand sales by 11,700 GWh and 13,400 GWh under the mid-low and mid-mid scenarios, respectively, by 2030.
- Traditional AAEE, additional SB 350 savings, and AAPV reduce mid demand peak by 1,800 MW and 2,250 MW under the mid-low and mid-mid scenarios, respectively, by 2030.

Electricity Consumption and Sales

The *CED 2017 Revised* high, mid, and low demand case results for baseline electricity consumption are shown in **Figure 44**, along with the mid case from *CEDU 2016*. With higher EV, residential (excluding EVs), and manufacturing forecasts, average annual growth in consumption in the new mid case is higher than in *CEDU 2016*. Annual growth from 2016 — 2027 for the *CED 2017 Revised* forecast averages 1.66 percent, 1.37 percent, and 1.07 percent in the high, mid and low cases, respectively, compared to 1.13 percent in the *CEDU 2016* mid case.

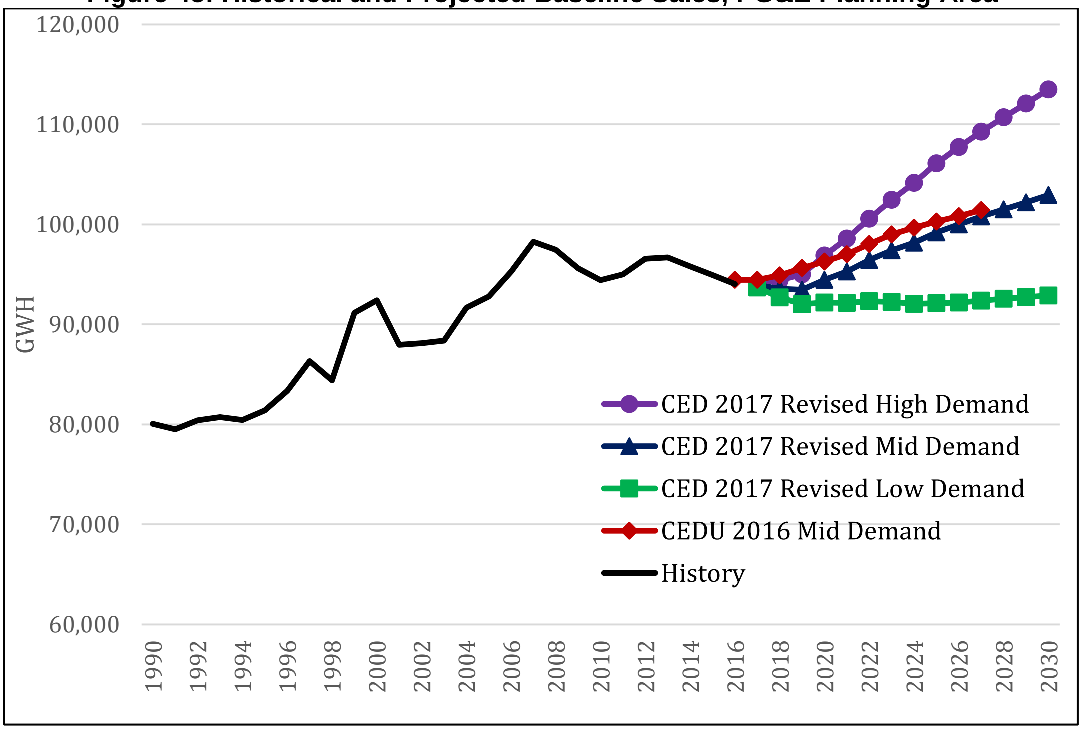
Figure 44: Historical and Projected Baseline Consumption, PG&E Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Projected baseline electricity sales for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case for PG&E are shown in **Figure 45**. All three new forecast cases are lower than the *CEDU 2016* mid case at the beginning of the forecast period, reflecting higher projected self-generation energy impacts and additional committed efficiency program savings. Higher consumption growth thereafter brings the new mid case to almost the same level as CEDU 2016 by 2027. Annual growth from 2016-2027 for the *CED 2017 Revised* forecast averages 1.37 percent, 0.63 percent, and -0.16 percent in the high, mid and low cases, respectively, compared to 0.65 percent in the *CEDU 2016* mid case.

Figure 45: Historical and Projected Baseline Sales, PG&E Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

The demand forms accompanying this report[84] provide results for consumption and sales by the six forecast zones within the PG&E planning area. Staff does not provide a breakout for peak demand since the peak shift is not yet measured below the planning area level. Forecast Zone 2 (Northern Coast) shows the fastest growth in sales and consumption over 2016 — 2030 in the mid case; although population growth is relatively low, growth in per capita income is highest in this zone. In addition, Forecast Zone 2 has a relatively high share of EV ownership and therefore higher absolute growth in EV consumption. The next highest sales and consumption growth is projected for Forecast Zone 4 (Central Valley), based on high population growth due to inland migration. Forecast Zone 3 (Northern Valley), with the lowest growth in population and employment among the six forecast zones, yields the slowest consumption and sales growth.

84 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

Table 23 shows the traditional AAEE, additional SB 350, and AAPV consumption savings estimated for PG&E for the mid-low and mid-mid scenarios, the two scenarios to be used for the planning forecasts, while **Table 24** provides the estimates for the high-low and low-high scenarios. These estimates include savings for the PG&E service territory and for POUs within the PG&E planning area. By 2030, savings from these three sources combined reach about 11,700 GWh and 13,400 GWh in the mid-low and mid-mid scenarios, respectively.

Table 23: Traditional AAEE, SB 350, and AAPV Consumption Savings (GWh), PG&E Mid-Low and Mid-Mid Scenarios

	Mid-Low			Mid-Mid		
	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV
2017	48	52		60	52	
2018	769	103		887	103	
2019	1,504	114		1,784	114	
2020	2,223	117	65	2,652	159	75
2021	2,983	113	186	3,560	199	213
2022	3,729	111	307	4,447	240	351
2023	4,601	108	428	5,502	279	489
2024	5,397	104	547	6,447	318	626
2025	6,176	99	667	7,371	356	763
2026	6,906	94	787	8,266	394	899
2027	7,634	91	905	9,140	433	1,035
2028	8,339	88	1,022	9,961	473	1,167
2029	8,991	87	1,135	10,714	515	1,297
2030	9,647	85	1,246	11,460	556	1,424

Source: California Energy Commission, Energy Assessments Division, 2017.

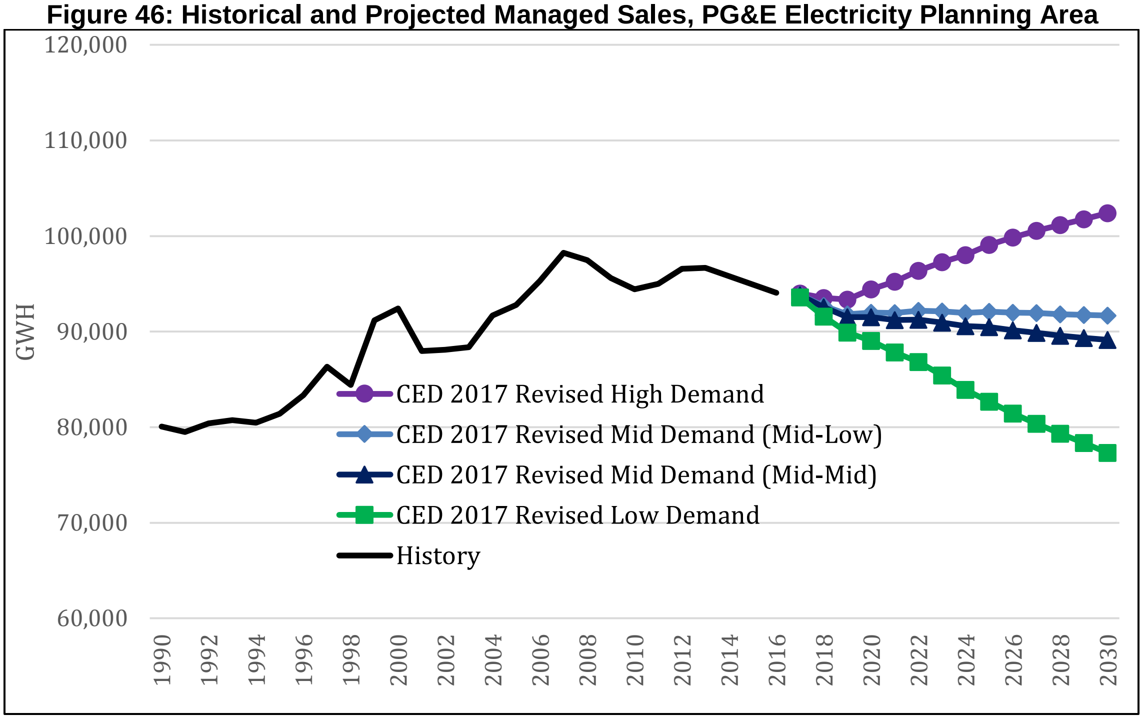
Figure 46 shows the managed sales forecasts for PG&E after adjusting for these three savings sources. The managed mid demand cases begin to decline as the additional savings counters the effects of increasing EV consumption, while sales in the low case decline throughout the forecast period. In the managed high demand case, sales growth from 2017 onward is reduced by more than 50 percent. Annual growth from 2016 — 2030 in the managed mid demand case averages -0.16 percent and -0.35 percent under the mid-low and mid-mid scenarios, respectively. Over this period, average annual growth in the high and low managed demand cases equals 0.62 percent and -1.37 percent, respectively.

Table 24: Traditional AAEE, SB 350, and AAPV Consumption Savings (GWh), PG&E High-Low and Low-High Scenarios

	High-Low			Low-High		
	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV
2017	48	52		62	52	
2018	769	103		983	103	
2019	1,505	114		1,937	114	
2020	2,193	117	98	2,849	159	52
2021	2,872	113	280	3,843	209	146
2022	3,539	111	465	4,833	260	238
2023	4,333	108	650	5,989	309	328
2024	5,053	104	834	7,019	469	417
2025	5,758	99	1,020	8,039	633	505
2026	6,416	94	1,206	9,026	809	592
2027	7,073	91	1,391	9,999	987	678
2028	7,707	88	1,573	10,911	1,166	762
2029	8,287	87	1,751	11,727	1,370	844
2030	8,879	85	1,927	12,532	1,561	921

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 46: Historical and Projected Managed Sales, PG&E Electricity Planning Area



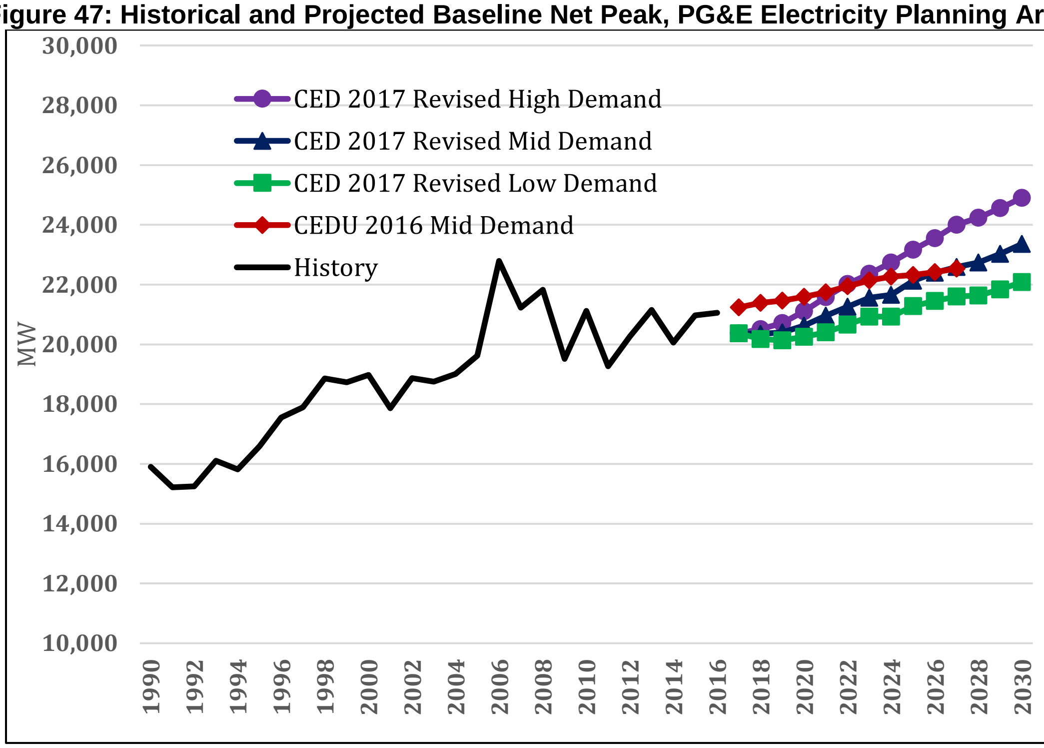
Source: California Energy Commission, Energy Assessments Division, 2017.

Peak Demand

The *CED 2017 Revised* high, mid, and low demand case results for baseline net peak are shown in **Figure 47**, along with the mid case from *CEDU 2016*. The new forecast starts below *CEDU 2016* as the most recent load data yield a lower (weather-normalized) value in 2017. Because the peak shift is incorporated in *CED 2017 Revised*, the new mid case grows faster than *CEDU 2016*, reaching the same level by 2027. Indeed, peak demand grows faster than baseline sales in each demand case due to the peak shift. Annual growth from 2017 — 2027 for the *CED 2017 Revised* forecast averages 1.65 percent, 1.04 percent, and 0.59 percent in the high, mid and low cases, respectively, compared to 0.59 percent in the *CEDU 2016* mid case.

Table 25 gives the impact of the peak shift on baseline demand for the three cases, showing the "traditional" peaks (load estimated for the traditional peak hour), the amounts induced by the shift, and the final peaks as provided in **Figure 47**. The amount of the shift is highest in the low demand case since PV generation is highest. Without the peak shift, growth in the new mid case is similar to *CEDU 2016*. By the end of the forecast period, peak demand has moved two hours later in each of the demand cases, to 7-8 pm.

Figure 47: Historical and Projected Baseline Net Peak, PG&E Electricity Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 25: Impact of Peak Shift on PG&E Baseline Net Peak (MW)

	High Demand Case			Mid Demand Case			Low Demand Case		
	Trad. Peak	Peak Shift	Final Peak	Trad. Peak	Peak Shift	Final Peak	Trad. Peak	Peak Shift	Final Peak
2017	20,029	338	20,367	20,029	338	20,367	20,029	338	20,367
2018	20,072	438	20,510	19,875	474	20,349	19,672	511	20,183
2019	20,207	504	20,711	19,812	592	20,404	19,453	680	20,133
2020	20,576	533	21,109	19,941	692	20,632	19,345	914	20,259
2021	20,995	585	21,580	20,150	816	20,966	19,357	1,044	20,400
2022	21,405	617	22,022	20,337	925	21,262	19,334	1,333	20,667
2023	21,736	633	22,370	20,406	1,153	21,559	19,154	1,774	20,927
2024	22,072	670	22,742	20,509	1,151	21,660	19,048	1,881	20,929
2025	22,472	699	23,172	20,673	1,459	22,131	18,997	2,284	21,280
2026	22,810	741	23,551	20,801	1,598	22,399	18,946	2,507	21,453
2027	23,204	795	23,999	21,041	1,551	22,592	19,066	2,539	21,605
2028	23,431	810	24,241	21,043	1,694	22,736	18,887	2,745	21,632
2029	23,709	852	24,561	21,145	1,884	23,029	18,846	2,995	21,840
2030	23,992	915	24,906	21,243	2,117	23,360	18,796	3,286	22,081

Source: California Energy Commission, Energy Assessments Division, 2017.

Table 26 shows AAEE (including additional SB 350 savings) and AAPV peak demand savings estimated for PG&E for the mid-low and mid-mid scenarios, the two scenarios to be used for the planning forecasts, while **Table 27** provides the estimates for the high-low and low-high scenarios. The AAEE estimates are provided both for the service territory and for POUs within the planning area. The estimates account for peak shift, so AAEE savings at peak are reduced as they generally occur later in the day. For the same reason, AAPV peak reductions are quite low relative to corresponding capacity additions. By 2030, savings from these three sources combined reach about 1,800 MW and 2,250 MW in the mid-low and mid-mid scenarios, respectively. Note that results begin in 2018; AAEE peak savings are incorporated incremental to 2017, since the hourly load model is calibrated to actual historical 2017 peaks.

Table 26: AAEE and AAPV Peak Demand Savings (MW), PG&E Mid-Low and Mid-Mid Scenarios

	Mid-Low			Mid-Mid		
	Service Territory AAEE*	POU AAEE*	AAPV	Service Territory AAEE*	POU AAEE*	AAPV
2018	129	12	-	147	12	-
2019	249	24	-	296	26	-
2020	368	38	9	451	41	10
2021	494	52	19	614	57	22
2022	619	66	31	774	74	35
2023	732	74	7	915	84	8
2024	872	88	9	1,091	101	11
2025	1,009	102	11	1,264	117	13
2026	1,134	114	13	1,427	132	15
2027	1,262	126	7	1,591	146	9
2028	1,390	138	17	1,751	160	19
2029	1,507	148	19	1,897	172	21
2030	1,625	159	21	2,042	185	23
*Includes additional SB 350 savings. NOTE: Includes line losses.						

Source: California Energy Commission, Energy Assessments Division, 2017.

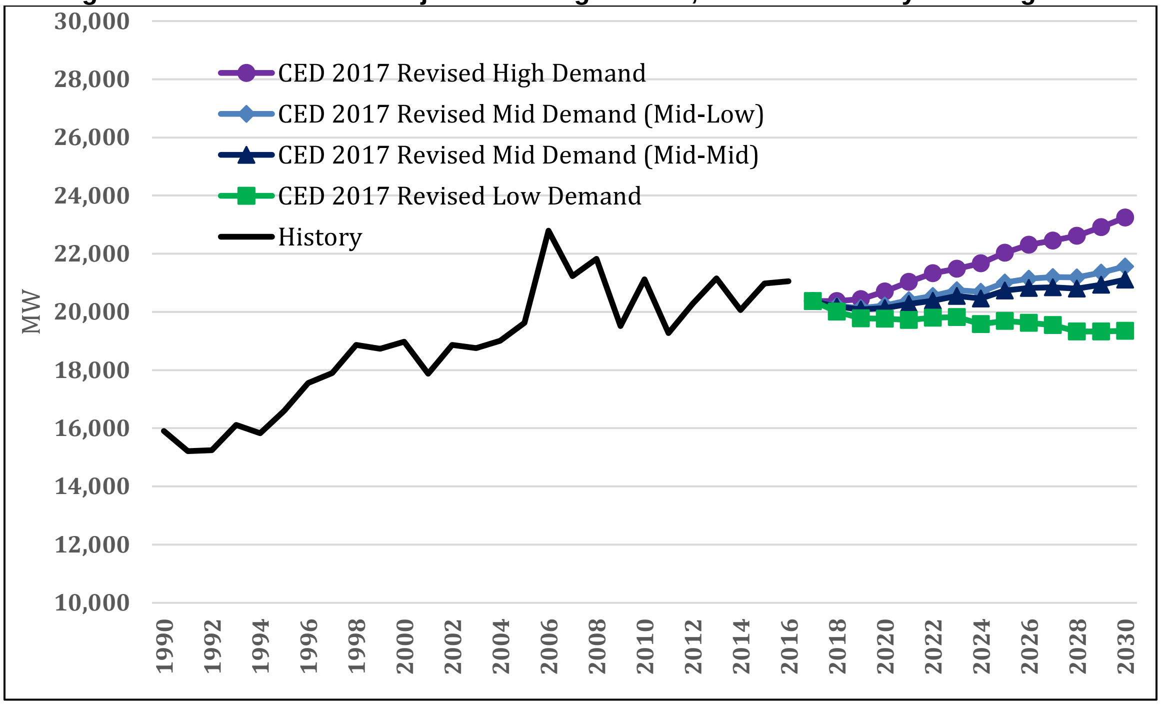
Table 27: AAEE and AAPV Peak Demand Savings (MW), PG&E High-Low and Low-High Scenarios

	High-Low			Low-High		
	Service Territory AAEE*	POU AAEE*	AAPV	Service Territory AAEE*	POU AAEE*	AAPV
2018	129	12	-	164	12	-
2019	249	24	-	324	26	-
2020	362	37	13	457	38	1
2021	472	50	28	624	53	3
2022	581	62	46	793	69	2
2023	739	72	70	1,010	88	6
2024	886	95	90	1,232	108	7
2025	932	94	109	1,456	128	9
2026	1,043	105	98	1,672	147	10
2027	1,297	122	132	1,891	166	6
2028	1,332	126	166	2,105	183	13
2029	1,376	135	140	2,302	200	15
2030	1,482	145	31	2,497	216	16
*Includes additional SB 350 savings. NOTE: Includes line losses.						

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 48 shows the managed net peak demand forecasts for PG&E after adjusting for these savings sources. Peak demand in the managed mid demand case, unlike sales, increases slightly over the forecast period under both the mid-low and mid-mid scenarios as the peak shift mutes the impact of additional efficiency savings. Annual growth from 2017 — 2030 in the managed mid demand case averages 0.44 percent and 0.28 percent for the mid-low and mid-mid scenarios, respectively. Over this period, average annual growth in the high and low managed demand cases equals 1.02 percent and -0.39 percent, respectively.

Figure 48: Historical and Projected Managed Peak, PG&E Electricity Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 28 gives the impact of the peak shift for the two mid case scenarios, showing the "traditional" peaks (load estimated for the traditional peak hour), the amounts induced by the shift, and the final peaks as provided in **Figure 48**. **Table 29** provides these totals for the high and low demand cases. The differences between AAEE at the traditional peak hour and the shifted peak hour increase the impacts of the peak shift in all three demand cases. There is no movement in the peak hour compared to the baseline peak: peak demand remains two hours later by the end of the forecast period in each of the demand cases.

Table 28: Impact of Peak Shift on PG&E Managed Net Peak (MW), Mid Demand Case

	Mid Demand (Mid-Low)			Mid Demand (Mid-Mid)		
	Traditional Peak	Peak Shift	Final Peak	Traditional Peak	Peak Shift	Final Peak
2017	20,029	338	20,367	20,029	338	20,367
2018	19,729	479	20,209	19,710	480	20,190
2019	19,528	602	20,130	19,478	604	20,082
2020	19,501	717	20,218	19,408	722	20,130
2021	19,538	862	20,400	19,401	872	20,273
2022	19,554	992	20,546	19,374	1,006	20,380
2023	19,387	1,359	20,745	19,144	1,408	20,552
2024	19,270	1,421	20,691	18,973	1,485	20,458
2025	19,219	1,791	21,010	18,868	1,870	20,738
2026	19,146	1,991	21,138	18,739	2,086	20,825
2027	19,192	2,005	21,196	18,732	2,114	20,846
2028	18,982	2,210	21,192	18,473	2,333	20,806
2029	18,894	2,461	21,355	18,341	2,597	20,938
2030	18,802	2,754	21,556	18,206	2,904	21,110

Source: California Energy Commission, Energy Assessments Division, 2017.

Table 29: Impact of Peak Shift on PG&E Managed Net Peak (MW), High and Low Demand Cases

	High Demand			Low Demand		
	Traditional Peak	Peak Shift	Final Peak	Traditional Peak	Peak Shift	Final Peak
2017	20,029	338	20,367	20,029	338	20,367
2018	19,926	444	20,370	19,488	517	20,006
2019	19,923	514	20,437	19,089	694	19,783
2020	20,134	563	20,697	18,779	984	19,763
2021	20,386	644	21,030	18,564	1,156	19,720
2022	20,628	705	21,333	18,312	1,492	19,803
2023	20,724	764	21,488	17,816	2,008	19,824
2024	20,843	829	21,671	17,387	2,194	19,581
2025	21,029	1,007	22,036	17,011	2,676	19,687
2026	21,167	1,138	22,305	16,646	2,977	19,624
2027	21,372	1,076	22,447	16,455	3,087	19,543
2028	21,384	1,231	22,616	15,957	3,373	19,330
2029	21,474	1,435	22,909	15,623	3,700	19,323
2030	21,566	1,683	23,249	15,284	4,067	19,351

Source: California Energy Commission, Energy Assessments Division, 2017.

SCE Planning Area

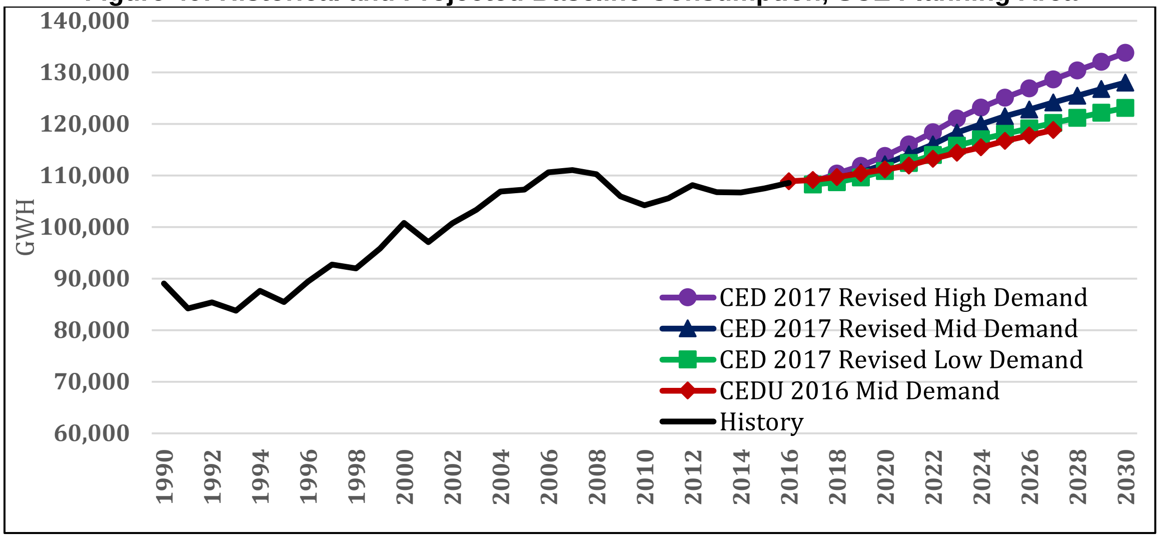
The SCE planning area includes:

- SCE bundled retail customers.
- Customers served by energy service providers using the SCE distribution system to deliver electricity to end users.
- Customers of the various Southern California municipal and irrigation district utilities within the SCE TAC area (**Table 4**).
- Key factors incorporated in the forecast include the following:
- Projected population growth averages 0.70 percent per year over 2016-2030, lower than the average for the state as a whole (0.81 percent). Projected growth in the number of households in the mid case averages 0.89 percent per year, also lower than the state average (0.94 percent).
- Per capita income growth averages 1.78 percent per year from 2016-2030, lower than the state average (1.88 percent).
- EV electricity consumption by 2030 is projected to be about 4,500 GWh, 4,000 GWh, and 3,000 GWh in the high, mid, and low demand cases, respectively.
- Additional electrification adds 610 GWh, 340 GWh, and 130 GWh to consumption in the high, mid, and low cases, respectively, by 2030.
- Projected behind-the-meter PV installed capacity reaches 3,700 MW, 6,900 MW and 10,100 MW in the high, mid, and low demand cases, respectively, by 2030.
- Incremental climate change impacts are projected to add 620 GWh and 600 GWh to annual consumption and 510 MW and 270 MW to peak demand by 2030 in the high and mid demand cases, respectively.
- Traditional AAEE, additional SB 350 savings, and AAPV reduce mid demand sales by 12,900 GWh and 14,800 GWh under the mid-low and mid-mid scenarios, respectively, by 2030.
- Traditional AAEE, additional SB 350 savings, and AAPV reduce mid demand peak by 2,700 MW and 3,200 MW under the mid-low and mid-mid scenarios, respectively, by 2030.

Electricity Consumption and Sales

The *CED 2017 Revised* high, mid, and low demand case results for baseline electricity consumption are shown in **Figure 49**, along with the mid case from *CEDU 2016*. As with PG&E, higher EV, residential (excluding EVs), and manufacturing forecasts push average annual growth in consumption in the new mid case higher than in *CEDU 2016*. By 2027, all three new cases show higher consumption than *CEDU 2016*. Annual growth from 2016 — 2027 for the *CED 2017 Revised* forecast averages 1.55 percent, 1.23 percent, and 0.90 percent in the high, mid and low cases, respectively, compared to 0.80 percent in the *CEDU 2016* mid case.

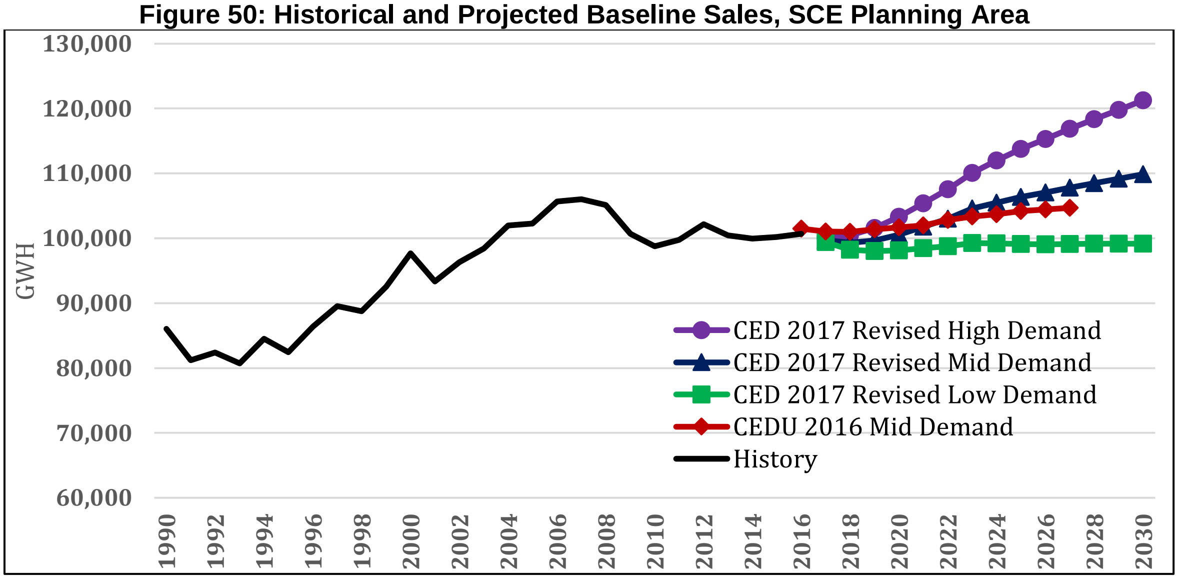
Figure 49: Historical and Projected Baseline Consumption, SCE Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Projected baseline electricity sales for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case for the SCE planning area are shown in **Figure 50**. The new cases begin below *CEDU 2016* mid as new efficiency program savings are added and more electricity is generated from PV. With less growth in PV generation than PG&E however, faster consumption growth pushes the new mid case above *CEDU 2016* by 2023. Annual growth from 2016 — 2027 for the *CED 2017 Revised* forecast averages 1.36 percent, 0.62 percent, and -0.14 percent in the high, mid, and low cases, respectively, compared to 0.28 percent in the *CEDU 2016* mid case.

Figure 50: Historical and Projected Baseline Sales, SCE Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

The demand forms accompanying this report[85] provide results for consumption and sales by the five forecast zones within the SCE planning area. Staff does not provide a breakout for peak demand since the peak shift is not yet measured below the planning area level. Forecast Zone 10 (San Bernardino County) and Forecast Zone 11 (Riverside County) show the fastest growth in consumption over 2016 — 2030 in the mid case, with high projected population growth due to inland migration, although high rates of PV adoption push growth in sales below that of Forecast Zone 8 (Santa Barbara and Ventura Counties), which has the highest projected growth in per capita income. Forecast Zone 9 (Southern Valley), with relatively low growth in population and per capita income, yields the slowest consumption and sales growth.

Table 30 shows the traditional AAEE, additional SB 350, and AAPV consumption savings estimated for SCE for the mid-low and mid-mid scenarios, the two scenarios to be used for the planning forecasts, while **Table 31** provides the estimates for the high-low and low-high scenarios. These estimates include savings for the SCE service territory and for POUs within the SCE planning area. By 2030, savings from these three sources combined reach about 12,900 GWh and 14,800 GWh in the mid-low and mid-mid scenarios, respectively.

Table 30: Traditional AAEE, SB 350, and AAPV Consumption Savings (GWh), SCE Mid-Low and Mid-Mid Scenarios

	Mid-Low			Mid-Mid		
	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV
2017	49	53		62	53	
2018	764	104		878	104	
2019	1,525	115		1,763	115	
2020	2,295	118	63	2,654	162	72
2021	3,102	115	184	3,609	202	210
2022	3,910	113	307	4,557	244	351
2023	4,866	110	430	5,695	284	491
2024	5,739	106	551	6,771	323	630
2025	6,618	101	674	7,834	361	770
2026	7,513	96	796	8,857	400	910
2027	8,413	92	916	9,882	440	1,047
2028	9,280	90	1,034	10,876	481	1,182
2029	10,120	89	1,151	11,835	523	1,315
2030	10,959	87	1,265	12,783	565	1,446

Source: California Energy Commission, Energy Assessments Division, 2017.

85 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

Table 31: Traditional AAEE, SB 350, and AAPV Consumption Savings (GWh), SCE High-Low and Low-High Scenarios

	High-Low			Low-High		
	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV
2017	49	53		64	53	
2018	764	104		948	104	
2019	1,525	115		1,910	115	
2020	2,263	118	87	2,920	162	57
2021	2,985	115	254	4,003	212	166
2022	3,710	113	427	5,055	264	275
2023	4,585	110	601	6,294	314	382
2024	5,378	106	773	7,435	477	488
2025	6,179	101	947	8,584	643	593
2026	6,998	96	1,121	9,723	822	698
2027	7,822	92	1,293	10,872	1,003	801
2028	8,614	90	1,461	11,961	1,185	902
2029	9,379	89	1,629	12,983	1,392	1,001
2030	10,144	87	1,794	13,991	1,587	1,098

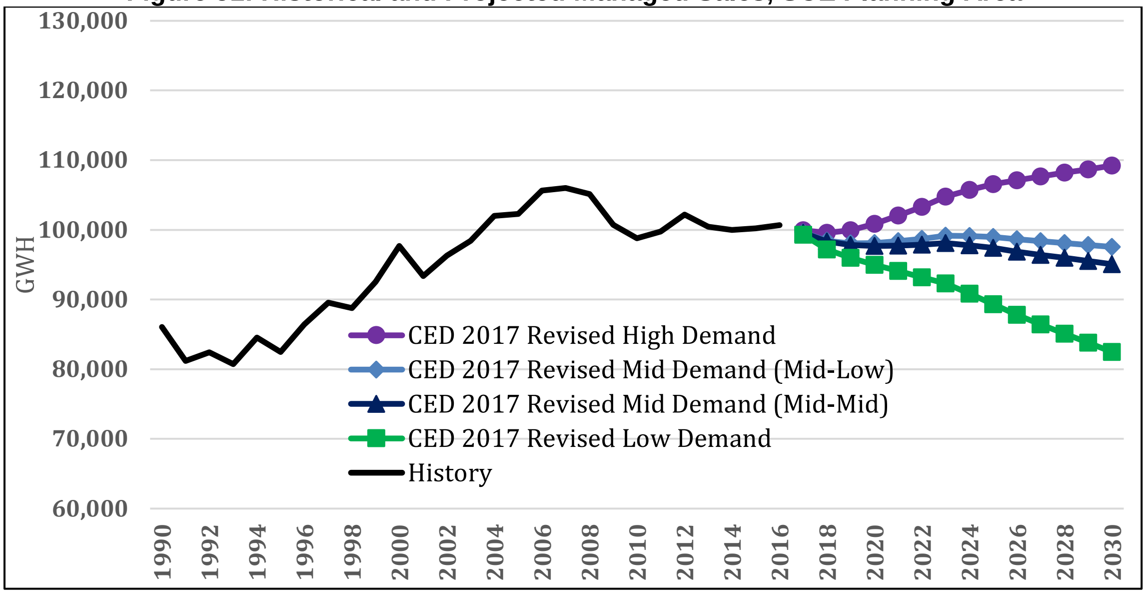
Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 51 shows the managed sales forecasts for SCE after adjusting for these three savings sources. The managed mid demand cases begin to decline as the additional savings more than counters the effects of increasing EV consumption, while sales in the low case decline throughout the forecast period. In the managed high demand case, sales growth from 2017 onward is reduced by more than 50 percent. Annual growth from 2016 — 2030 in the managed mid demand case averages -0.15 percent and -0.32 percent under the mid-low and mid-mid scenarios, respectively. Over this period, average annual growth in the high and low managed demand cases equals 0.65 percent and -1.37 percent, respectively.

Peak Demand

The *CED 2017 Revised* high, mid, and low demand case results for baseline net peak are shown in **Figure 52**, along with the mid case from *CEDU 2016*. The new forecast starts above *CEDU 2016* as the most recent load data yield a higher (weather-normalized) value in 2017. The peak shift causes the new mid case to grow faster than *CEDU 2016*. Annual growth from 2017 — 2027 for the *CED 2017 Revised* forecast averages 1.45 percent, 0.55 percent, and -0.40 percent in the high, mid and low cases, respectively, compared to 0.14 percent in the *CEDU 2016* mid case.

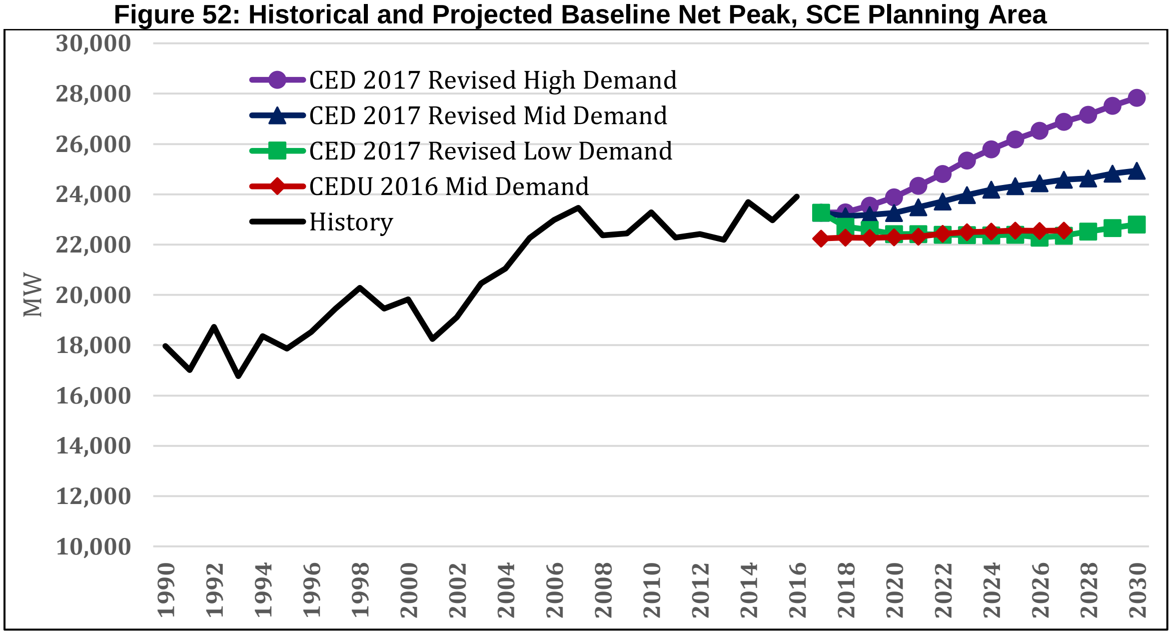
Figure 51: Historical and Projected Managed Sales, SCE Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 32 gives the impact of the peak shift on baseline demand for the three cases, showing the "traditional" peaks, the amounts induced by the shift, and the final peaks as provided in **Figure 52**. Peak shift impacts are noticeably lower than for PG&E, a function mainly of lower PV generation overall and a later peak day (early September vs. mid-August), which reduces PV impact further. In addition, less projected EV sales means less impact in the early evening hours. By the end of the forecast period, peak demand has moved one hour later in high and mid cases, although AAPV causes an additional hour shift, as discussed below. In the low case, higher PV generation pushes the peak four hours later.

Figure 52: Historical and Projected Baseline Net Peak, SCE Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 32: Impact of Peak Shift on SCE Baseline Net Peak (MW)

	High Demand Case			Mid Demand Case			Low Demand Case		
	Trad. Peak	Peak Shift	Final Peak	Trad. Peak	Peak Shift	Final Peak	Trad. Peak	Peak Shift	Final Peak
2017	23,130	142	23,272	23,130	142	23,272	23,130	142	23,272
2018	23,087	200	23,286	22,903	227	23,130	22,460	259	22,719
2019	23,346	212	23,558	22,908	278	23,186	22,243	347	22,590
2020	23,775	106	23,881	23,067	196	23,263	22,171	253	22,424
2021	24,235	105	24,340	23,247	243	23,489	22,077	339	22,415
2022	24,710	106	24,816	23,431	288	23,720	21,972	427	22,400
2023	25,285	58	25,344	23,697	280	23,977	21,930	447	22,377
2024	25,703	94	25,796	23,803	381	24,183	21,693	677	22,370
2025	26,099	93	26,192	23,911	422	24,334	21,514	878	22,392
2026	26,444	89	26,533	23,991	456	24,447	21,346	937	22,283
2027	26,785	102	26,887	24,082	505	24,587	21,208	1,152	22,360
2028	27,114	55	27,170	24,164	473	24,637	21,068	1,455	22,523
2029	27,415	110	27,525	24,256	573	24,829	20,957	1,702	22,660
2030	27,727	113	27,840	24,330	608	24,938	20,810	1,998	22,808

Source: California Energy Commission, Energy Assessments Division, 2017.

Table 33 shows AAEE (including additional SB 350 savings) and AAPV peak demand savings estimated for SCE for the mid-low and mid-mid scenarios, the two scenarios to be used for the planning forecasts, while **Table 34** provides the estimates for the high-low and low-high scenarios. The AAEE estimates are provided both for the service territory and for POUs within the planning area. The estimates account for peak shift, so AAEE savings at peak are reduced as they generally occur later in the day. AAPV reduces peak by more than for PG&E in general, although it has no impact in the low demand case (high PV) after 2026 because of the late peak hour. By 2030, savings from these sources combined reach about 2,700 MW and 3,200 MW in the mid-low and mid-mid scenarios, respectively. Note that results begin in 2018; AAEE peak savings are incorporated incremental to 2017, since the hourly load model is calibrated to actual historical 2017 peaks.

Figure 53 shows the managed net peak demand forecasts for SCE after adjusting for these savings sources. Although the peak shift mutes the impact of additional efficiency savings, the impact is less than for PG&E, and managed peak decreases slightly over the forecast period under both the mid-low and mid-mid scenarios Annual growth from 2017 — 2030 in the managed mid demand case averages -0.35 percent and -0.51 percent for the mid-low and mid-mid scenarios, respectively. Over this period, average annual growth in the high and low managed demand cases equals 0.55 percent and -1.21 percent, respectively.

Table 33: AAEE and AAPV Peak Demand Savings (MW), SCE Mid-Low and Mid-Mid Scenarios

	Mid-Low			Mid-Mid		
	Service Territory AAEE*	POU AAEE*	AAPV	Service Territory AAEE*	POU AAEE*	AAPV
2018	133	22	-	154	23	-
2019	262	46	-	310	47	-
2020	398	65	23	478	68	26
2021	537	87	54	660	93	62
2022	678	110	86	841	117	99
2023	882	138	119	1,103	149	136
2024	1,070	174	149	1,368	188	171
2025	1,267	200	181	1,621	218	207
2026	1,462	224	213	1,862	245	243
2027	1,655	231	243	2,076	256	278
2028	1,853	251	279	2,319	279	319
2029	1,986	279	299	2,521	270	323
2030	2,172	270	252	2,642	250	278
*Includes additional SB 350 savings. NOTE: Includes line losses.						

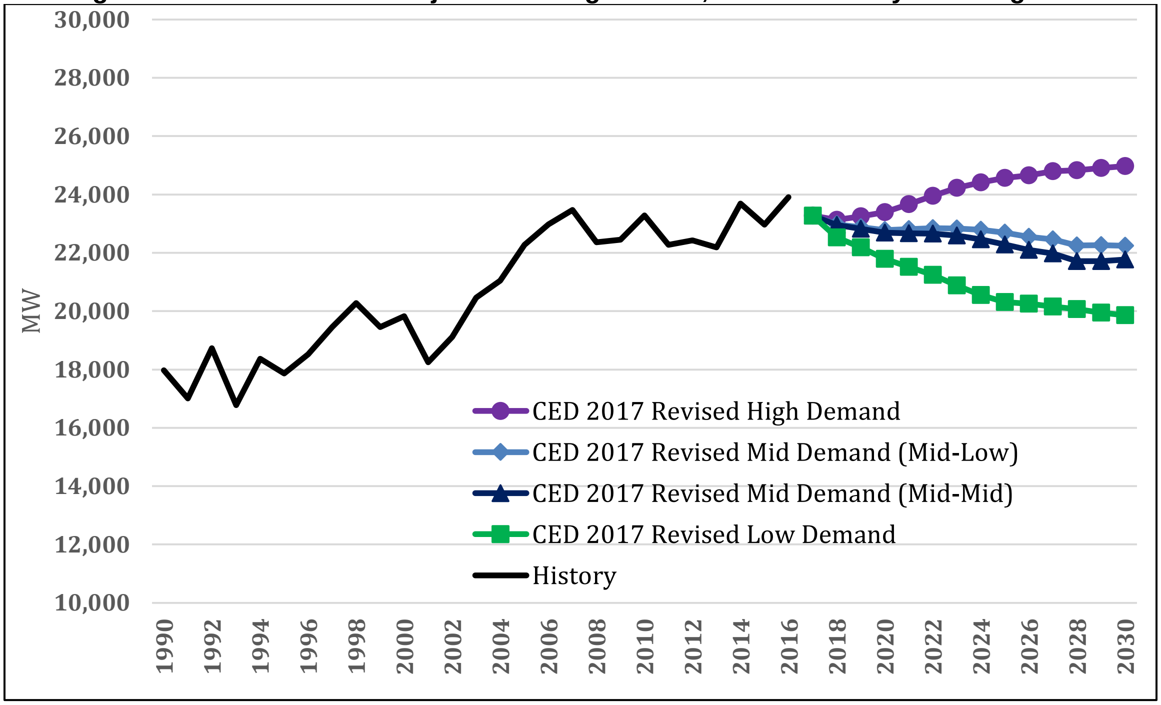
Source: California Energy Commission, Energy Assessments Division, 2017.

Table 34: AAEE and AAPV Peak Demand Savings (MW), SCE High-Low and Low-High Scenarios

	High-Low			Low-High		
	Service Territory AAEE*	POU AAEE*	AAPV	Service Territory AAEE*	POU AAEE*	AAPV
2018	133	22	-	174	23	-
2019	262	46	-	352	48	-
2020	391	64	32	542	69	21
2021	511	85	75	750	95	49
2022	634	105	120	956	121	77
2023	819	131	166	1,241	154	106
2024	1,001	167	209	1,539	193	87
2025	1,183	192	254	1,823	174	87
2026	1,365	214	299	1,741	196	95
2027	1,523	218	343	1,980	219	0
2028	1,704	236	394	2,214	240	0
2029	1,916	274	430	2,448	261	0
2030	2,096	292	473	2,667	280	0
*Includes additional SB 350 savings. NOTE: Includes line losses.						

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 53: Historical and Projected Managed Peak, SCE Electricity Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 35 gives the impact of the peak shift for the two mid case scenarios, showing the "traditional" peaks (load estimated for the traditional peak hour), the amounts induced by the shift, and the final peaks as provided in **Figure 53**. **Table 36** provides these totals for the high and low demand cases. The differences between AAEE at the traditional peak hour and the shifted peak hour increase the impacts of the peak shift in all three demand cases. By the end of the forecast period, peak demand has moved an additional three hours later (compared to the baseline forecast shift) to 7-8 pm in the mid case under both the mid-low and mid-mid scenarios, with one hour caused by AAPV and the other two by AAEE. The hour shifts are unchanged in the high and low demand cases compared to the baseline forecast (one hour for the high, four for the low).

Table 35: Impact of Peak Shift on SCE Managed Net Peak (MW), Mid Demand Case

	Mid Demand (Mid-Low)			Mid Demand (Mid-Mid)		
	Traditional Peak	Peak Shift	Final Peak	Traditional Peak	Peak Shift	Final Peak
2017	23,130	142	23,272	23,130	142	23,272
2018	22,745	230	22,975	22,724	229	22,953
2019	22,596	281	22,878	22,548	280	22,828
2020	22,568	209	22,777	22,481	209	22,690
2021	22,542	269	22,810	22,405	269	22,674
2022	22,518	327	22,845	22,333	329	22,662
2023	22,509	330	22,838	22,257	332	22,589
2024	22,343	447	22,790	22,006	450	22,456
2025	22,184	502	22,686	21,783	505	22,288
2026	21,999	549	22,548	21,544	554	22,098
2027	21,848	611	22,459	21,359	618	21,977
2028	21,667	587	22,254	21,124	594	21,719
2029	21,474	790	22,265	20,852	864	21,716
2030	21,291	954	22,245	20,614	1,155	21,768

Source: California Energy Commission, Energy Assessments Division, 2017.

Table 36: Impact of Peak Shift on SCE Managed Net Peak (MW), High and Low Demand Cases

	High Demand			Low Demand		
	Traditional Peak	Peak Shift	Final Peak	Traditional Peak	Peak Shift	Final Peak
2017	23,130	142	23,272	23,130	142	23,272
2018	22,929	202	23,131	22,261	261	22,522
2019	23,035	216	23,251	21,841	350	22,190
2020	23,272	123	23,395	21,530	262	21,792
2021	23,530	139	23,669	21,163	359	21,521
2022	23,799	157	23,957	20,788	458	21,246
2023	24,102	124	24,227	20,390	486	20,876
2024	24,235	183	24,418	19,740	810	20,550
2025	24,362	201	24,563	19,173	1,135	20,307
2026	24,439	216	24,654	18,622	1,629	20,251
2027	24,557	247	24,804	18,180	1,981	20,161
2028	24,624	210	24,835	17,667	2,401	20,069
2029	24,613	293	24,905	17,088	2,863	19,951
2030	24,664	315	24,979	16,573	3,288	19,860

Source: California Energy Commission, Energy Assessments Division, 2017.

SDG&E Electricity Planning Area

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

Key factors incorporated in the forecast include the following:

- Projected population growth averages 0.73 percent per year over 2016 — 2030, slightly lower than the average for the state as a whole (0.81 percent). Projected growth in the number of households in the mid case averages 0.81 percent per year, also slightly lower than the state average (0.94 percent).
- Per capita income growth averages 1.73 percent per year from 2016–2030, lower than the state average (1.88 percent).
- EV electricity consumption by 2030 is projected to be about 1,400 GWh, 1,250 GWh, and 950 GWh in the high, mid, and low demand cases, respectively.
- Additional electrification adds 80 GWh, 40 GWh, and 15 GWh to consumption in the high, mid, and low cases, respectively, by 2030.
- Projected behind-the-meter PV installed capacity reaches 1,100 MW, 1,800 MW, and 2,500 MW in the high, mid, and low demand cases, respectively, by 2030.

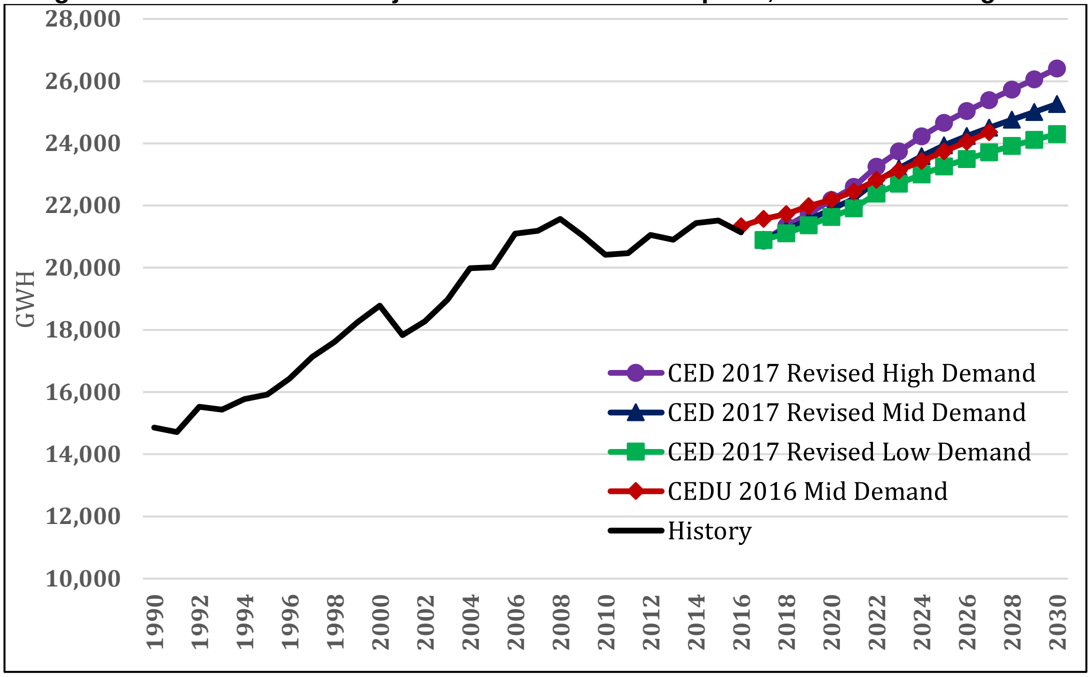
- Incremental climate change impacts are projected to add 125 GWh and 85 GWh to annual consumption and 130 MW and 70 MW to peak demand by 2030 in the high and mid demand cases, respectively.
- Traditional AAEE, additional SB 350 savings, and AAPV reduce mid demand sales by 2,550 GWh and 3,100 GWh under the mid-low and mid-mid scenarios, respectively, by 2030.
- Traditional AAEE, additional SB 350 savings, and AAPV reduce mid demand peak by 420 MW and 510 MW under the mid-low and mid-mid scenarios, respectively, by 2030.

Electricity Consumption and Sales

The *CED 2017 Revised* high, mid, and low demand case results for baseline electricity consumption are shown in **Figure 54**, along with the mid case from *CEDU 2016*. Additional efficiency programs push consumption in the new forecast below the projected 2017 level for *CEDU 2016*. A higher EV forecast pushes average annual growth in consumption in the new mid case higher than in *CEDU 2016* so that, by 2023, consumption in the new mid case rises above *CEDU* 2016. Annual growth from 2016 — 2027 for the *CED 2017 Revised* forecast averages 1.68 percent, 1.35 percent, and 1.05 percent in the high, mid and low cases, respectively, compared to 1.21 percent in the *CEDU 2016* mid case.

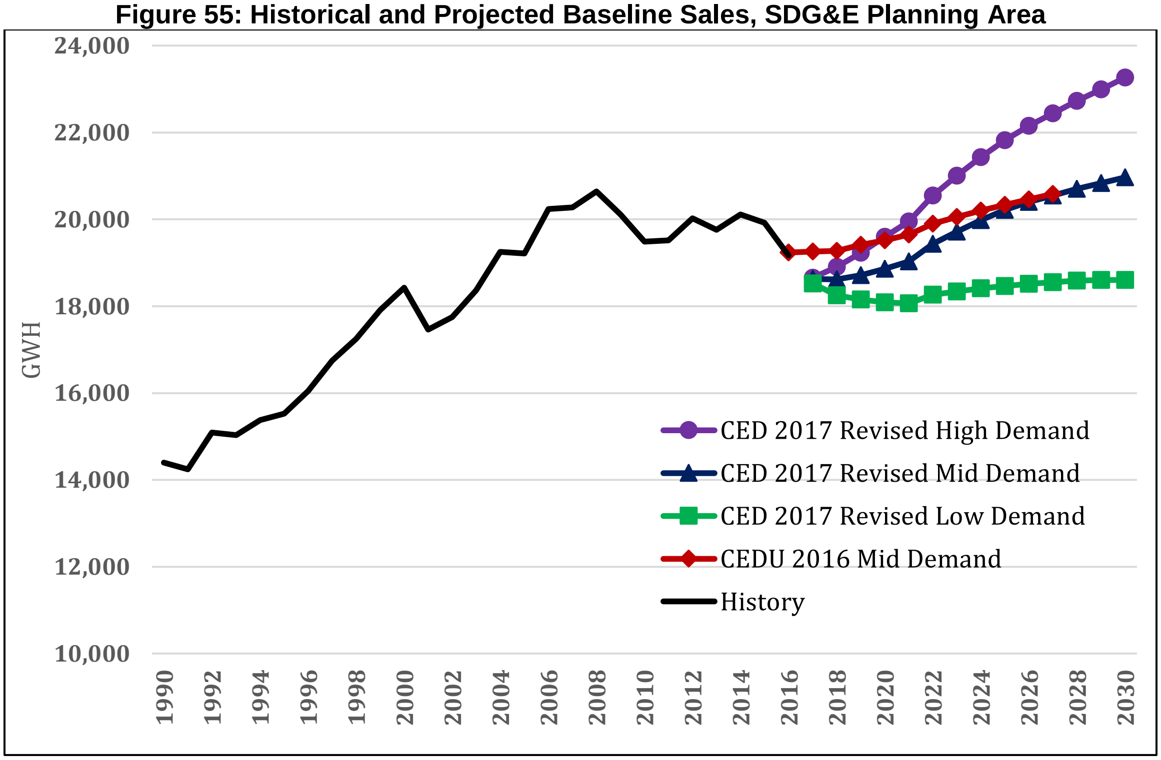
Projected baseline electricity sales for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case for the SDG&E planning area are shown in **Figure 55**. The new cases begin below *CEDU 2016* mid as new efficiency program savings are added and more electricity is generated from PV. Faster consumption growth thereafter pushes the new mid case to slightly below *CEDU 2016* by 2027. Annual growth from 2016 — 2027 for the *CED 2017 Revised* forecast averages 1.44 percent, 0.64 percent, and -0.30 percent in the high, mid, and low cases, respectively, compared to 0.62 percent in the *CEDU 2016* mid case.

Figure 54: Historical and Projected Baseline Consumption, SDG&E Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 55: Historical and Projected Baseline Sales, SDG&E Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 37 shows the traditional AAEE, additional SB 350, and AAPV consumption savings estimated for SDG&E for the mid-low and mid-mid scenarios, the two scenarios to be used for the planning forecasts, while **Table 38** provides the estimates for the high-low and low-high scenarios. By 2030, savings from these three sources combined reach about 2,550 GWh and 3,100 GWh in the mid-low and mid-mid scenarios, respectively.

Figure 56 shows the managed sales forecasts for SDG&E after adjusting for these three savings sources. The managed mid demand cases are relatively flat as the additional savings counters the effects of increasing EV consumption, while sales in the low case decline throughout the forecast period. In the managed high demand case, sales growth from 2017 onward is reduced by more than 50 percent. Annual growth from 2016 — 2030 in the managed mid demand case averages -0.29 percent and -0.50 percent under the mid-low and mid-mid scenarios, respectively. Over this period, average annual growth in the high and low managed demand cases equals 0.56 percent and -1.69 percent, respectively.

Table 37: Traditional AAEE, SB 350, and AAPV Consumption Savings (GWh), SDG&E Mid-Low and Mid-Mid Scenarios

	Mid-Low			Mid-Mid		
	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV
2017	10	11		13	11	
2018	140	21		164	21	
2019	282	24		341	24	
2020	425	24	11	520	33	13
2021	582	24	33	709	41	37
2022	744	23	55	900	50	62
2023	939	22	77	1,134	58	88
2024	1,129	22	99	1,354	66	113
2025	1,324	21	121	1,577	74	138
2026	1,516	20	143	1,802	82	164
2027	1,711	19	164	2,031	90	188
2028	1,910	18	186	2,258	98	212
2029	2,114	18	206	2,482	107	236
2030	2,320	18	226	2,711	116	259

Source: California Energy Commission, Energy Assessments Division, 2017.

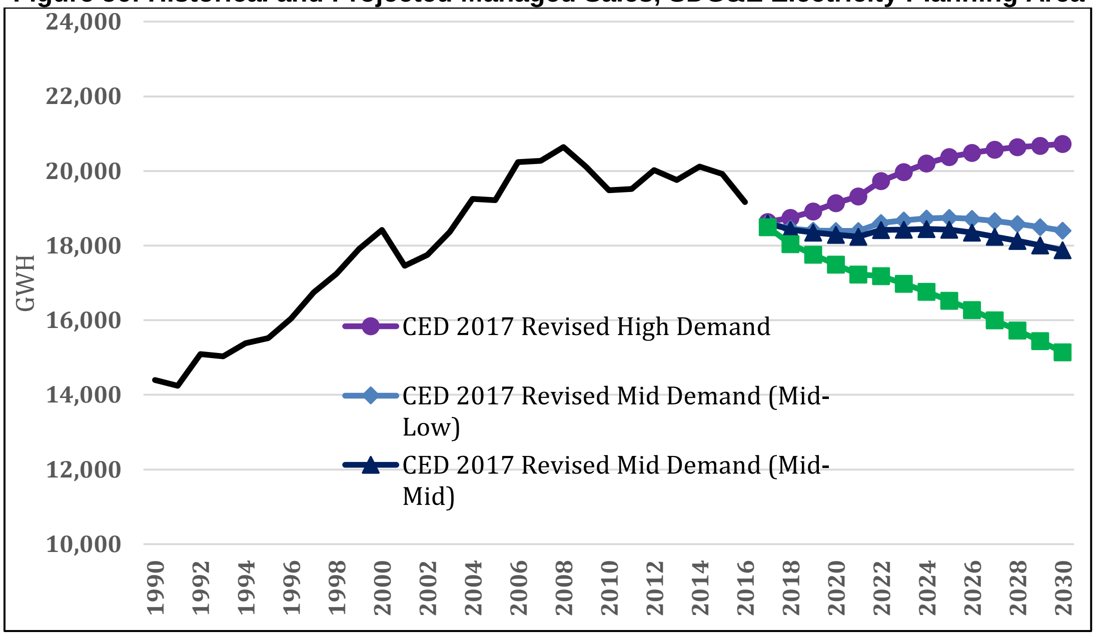
Table 38: Traditional AAEE, SB 350, and AAPV Consumption Savings (GWh), SDG&E High-Low and Low-High Scenarios

	High-Low			Low-High		
	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV
2017	10	11		13	11	
2018	140	21		184	21	
2019	282	24		371	24	
2020	418	24	18	559	33	8

	High-Low			Low-High		
	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV
2021	557	24	52	768	43	23
2022	701	23	87	981	54	38
2023	880	22	123	1,239	64	53
2024	1,053	22	159	1,481	98	67
2025	1,232	21	195	1,730	132	82
2026	1,408	20	231	1,981	168	96
2027	1,587	19	266	2,238	205	110
2028	1,772	18	300	2,490	242	124
2029	1,960	18	334	2,732	285	137
2030	2,150	18	368	2,979	325	149

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 56: Historical and Projected Managed Sales, SDG&E Electricity Planning Area

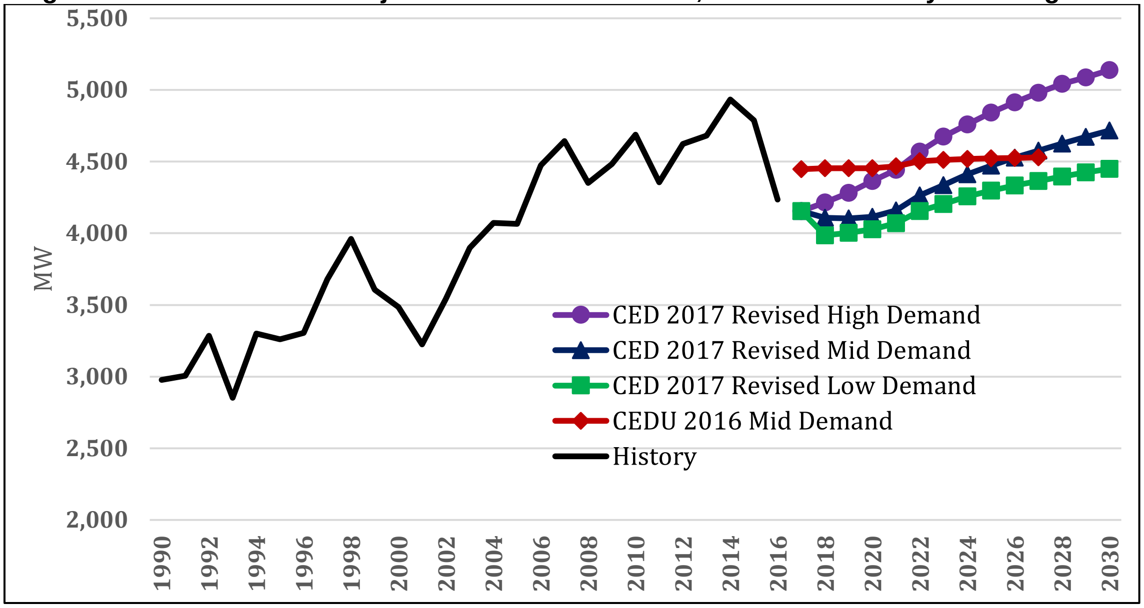


Source: California Energy Commission, Energy Assessments Division, 2017.

Peak Demand

The *CED 2017 Revised* high, mid, and low demand case results for baseline net peak are shown in **Figure 57**, along with the mid case from *CEDU 2016*. The new forecast starts below *CEDU 2016* as the most recent load data yield a lower (weather-normalized) value in 2017. The new mid and low cases grow faster than *CEDU 2016* due to incorporation of the peak shift, with the mid case reaching *CEDU 2016* by 2027. Annual growth from 2017 — 2027 for the *CED 2017 Revised* forecast averages 1.83 percent, 0.97 percent, and 0.50 percent in the high, mid and low cases, respectively, compared to 0.14 percent in the *CEDU 2016* mid case.

Figure 57: Historical and Projected Baseline Net Peak, SDG&E Electricity Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 39 gives the impact of the peak shift on baseline demand for the three cases, showing the "traditional" peaks, the amounts induced by the shift, and the final peaks as provided in **Figure 57.** Peak shift impacts are absent in the high demand case, but a four-hour shift by the end of the forecast period in the mid and low cases increases net peak by around 325 MW and 800 MW, respectively.

Table 39: Impact of Peak Shift on SDG&E Baseline Net Peak (MW)

	High Demand Case			Mid Demand Case			Low Demand Case		
	Trad. Peak	Peak Shift	Final Peak	Trad. Peak	Peak Shift	Final Peak	Trad. Peak	Peak Shift	Final Peak
2017	4,155	-	4,155	4,155	-	4,155	4,155	-	4,155
2018	4,215	-	4,215	4,109	-	4,109	3,986	-	3,986
2019	4,281	-	4,281	4,103	-	4,103	3,915	88	4,003
2020	4,364	-	4,364	4,114	-	4,114	3,858	170	4,028
2021	4,442	-	4,442	4,127	31	4,158	3,808	261	4,070
2022	4,569	-	4,569	4,194	70	4,264	3,815	341	4,156
2023	4,675	-	4,675	4,251	85	4,336	3,821	384	4,205
2024	4,758	-	4,758	4,274	136	4,410	3,783	475	4,258
2025	4,841	-	4,841	4,310	161	4,471	3,767	531	4,298
2026	4,912	-	4,912	4,337	191	4,528	3,750	582	4,333
2027	4,980	-	4,980	4,356	220	4,576	3,728	638	4,366
2028	5,043	-	5,043	4,390	235	4,625	3,734	663	4,397
2029	5,086	-	5,086	4,382	289	4,671	3,676	748	4,424
2030	5,138	-	5,138	4,390	326	4,716	3,643	807	4,449

Source: California Energy Commission, Energy Assessments Division, 2017.

Table 40 shows AAEE (including additional SB 350 savings) and AAPV peak demand savings estimated for SCE for the four scenarios used in the forecast. The estimates account for peak shift, so AAEE savings at peak are reduced as they generally occur later in the day. The later peak hour eliminates any impact from AAPV after 2020 in the mid-low, mid-mid, and mid-high scenarios. By 2030, savings from these sources combined reach about 420 MW and 510 MW in the mid-low and mid-mid scenarios, respectively. Note that results begin in 2018; AAEE peak savings are incorporated incremental to 2017, since the hourly load model is calibrated to actual historical 2017 peaks.

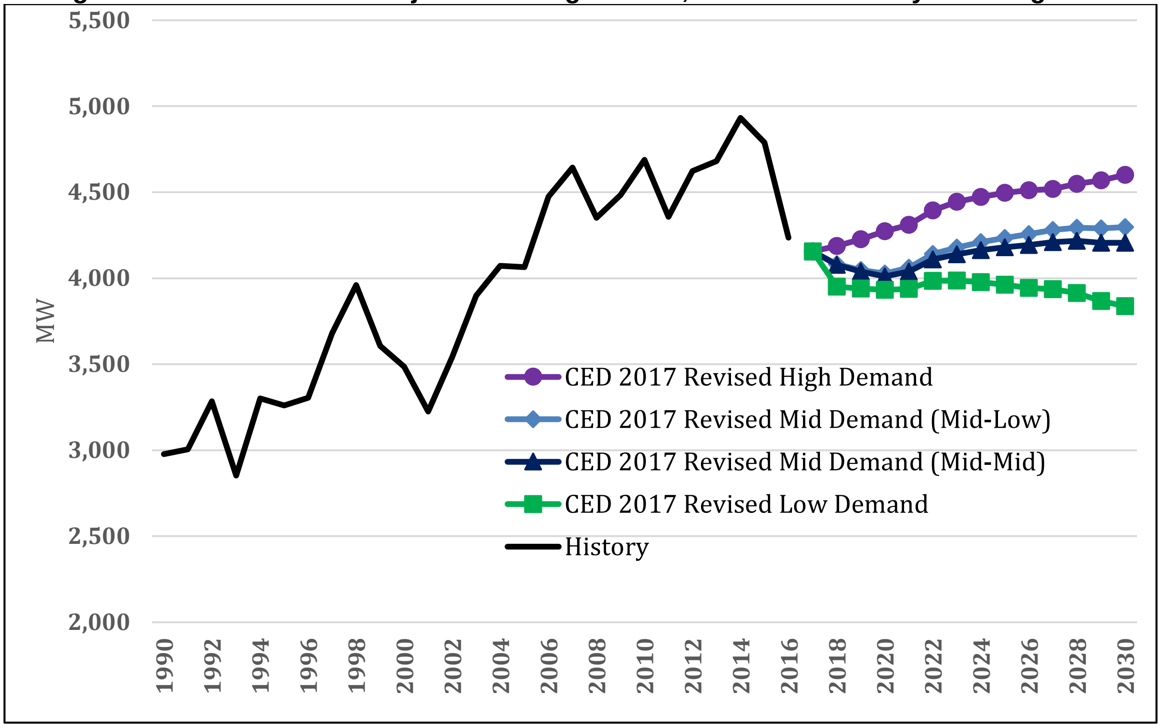
Table 40: AAEE and AAPV Peak Demand Savings (MW), SDG&E

	High-Low		Mid-Low		Mid-Mid		Low-High	
	AAEE*	AAPV	AAEE*	AAPV	AAEE*	AAPV	AAEE*	AAPV
2018	28	-	28	-	31	-	35	-
2019	55	-	55	-	65	-	63	-
2020	83	9	82	6	97	7	95	0
2021	111	21	97	0	121	0	132	0
2022	140	34	124	0	154	0	171	0
2023	185	45	159	0	198	0	219	0
2024	227	60	200	0	247	0	280	0
2025	272	73	236	0	291	0	335	0
2026	316	86	271	0	334	0	390	0
2027	363	98	296	0	365	0	429	0
2028	387	108	332	0	408	0	483	0
2029	395	123	382	0	466	0	557	0
2030	403	134	420	0	509	0	612	0
*Includes additional SB 350 savings. NOTE: Includes line losses.								

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 58 shows the managed net peak demand forecasts for SDG&E after adjusting for these savings sources. Peak demand in the managed mid demand case increases slightly over the forecast period under both the mid-low and mid-mid scenarios as the peak shift mutes the impact of additional efficiency savings. Annual growth from 2017 — 2030 in the managed mid demand case averages 0.26 percent and 0.09 percent for the mid-low and mid-mid scenarios, respectively. Over this period, average annual growth in the high and low managed demand cases equals 0.79 percent and -0.61 percent, respectively.

Figure 58: Historical and Projected Managed Peak, SDG&E Electricity Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 41 gives the impact of the peak shift for the two mid case scenarios, showing the "traditional" peaks (load estimated for the traditional peak hour), the amounts induced by the shift, and the final peaks as provided in **Figure 58**. **Table 42** provides these totals for the high and low demand cases. The differences between AAEE at the traditional peak hour and the shifted peak hour increase the impacts of the peak shift in the mid and low demand cases and induce a slight impact in the high demand case toward the end of the forecast period. The peak shift remains four hours in the mid and low cases by the end of the forecast period.

Table 41: Impact of Peak Shift on SDG&E Managed Net Peak (MW), Mid Demand Case

	Mid Demand (Mid-Low)			Mid Demand (Mid-Mid)		
	Traditional Peak	Peak Shift	Final Peak	Traditional Peak	Peak Shift	Final Peak
2017	4,155	-	4,155	4,155	-	4,155
2018	4,081	-	4,081	4,078	-	4,078
2019	4,048	-	4,048	4,038	-	4,038
2020	4,024	3	4,027	4,005	5	4,010
2021	3,998	63	4,061	3,971	67	4,038
2022	4,025	115	4,140	3,989	121	4,110
2023	4,027	150	4,177	3,978	160	4,138
2024	3,998	213	4,210	3,940	224	4,164
2025	3,979	256	4,235	3,910	271	4,180

	Mid Demand (Mid-Low)			Mid Demand (Mid-Mid)		
	Traditional Peak	Peak Shift	Final Peak	Traditional Peak	Peak Shift	Final Peak
2026	3,951	305	4,256	3,871	322	4,194
2027	3,910	369	4,280	3,817	394	4,210
2028	3,888	405	4,293	3,785	432	4,217
2029	3,826	463	4,289	3,717	489	4,206
2030	3,777	519	4,296	3,659	548	4,207

Source: California Energy Commission, Energy Assessments Division, 2017.

Table 42: Impact of Peak Shift on SDG&E Managed Net Peak (MW), High and Low Demand Cases

	High Demand			Low Demand		
	Traditional Peak	Peak Shift	Final Peak	Traditional Peak	Peak Shift	Final Peak
2017	4,155	-	4,155	4,155	-	4,155
2018	4,187	-	4,187	3,951	-	3,951
2019	4,226	-	4,226	3,844	96	3,939
2020	4,272	-	4,272	3,743	190	3,933
2021	4,309	-	4,309	3,643	294	3,937
2022	4,395	-	4,395	3,599	386	3,985
2023	4,444	-	4,444	3,534	451	3,985
2024	4,471	-	4,471	3,425	552	3,978
2025	4,497	-	4,497	3,334	629	3,963
2026	4,511	-	4,511	3,241	702	3,943
2027	4,519	-	4,519	3,132	805	3,937
2028	4,525	23	4,549	3,060	854	3,914
2029	4,508	61	4,569	2,933	934	3,867
2030	4,500	101	4,601	2,822	1,016	3,837

Source: California Energy Commission, Energy Assessments Division, 2017.

NCNC Planning Area

The Northern California Non-California ISO planning area includes the Turlock Irrigation District control area and the Balancing Authority of Northern California. By far the largest utility in this planning area is SMUD. Separate demand forms are provided for NCNC and SMUD.[86]

Key factors incorporated in the forecast include the following:

86 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

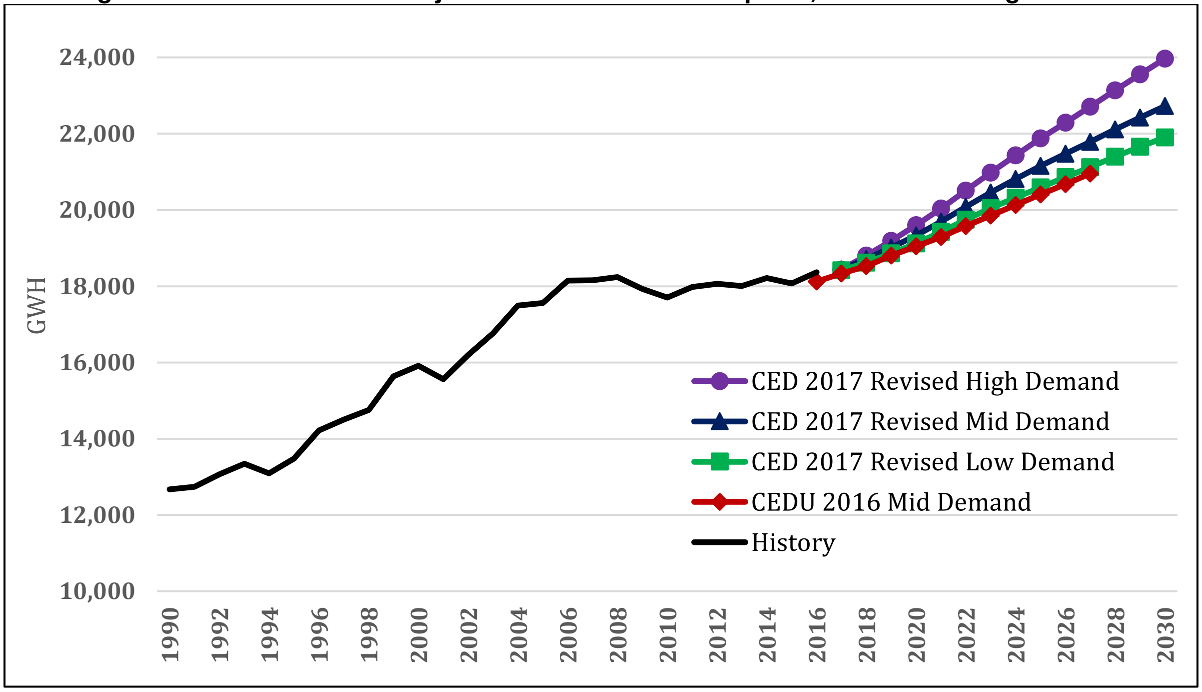
- Projected population growth averages 1.17 percent per year over 2016 — 2030, higher than the average for the state as a whole (0.81 percent) and highest of any planning area except for IID. Projected growth in the number of households in the mid case averages 1.12 percent per year, also higher than the state average (0.94 percent).
- Per capita income growth averages 1.85 percent per year from 2016-2030, slightly lower than the state average (1.88 percent).
- EV electricity consumption by 2030 is projected to be about 840 GWh, 750 GWh, and 610 GWh in the high, mid, and low demand cases, respectively.
- Additional electrification adds 60 GWh, 30 GWh, and 5 GWh to consumption in the high, mid, and low cases, respectively, by 2030.
- Projected behind-the-meter PV installed capacity reaches 520 MW, 800 MW, and 1,080 MW in the high, mid, and low demand cases, respectively, by 2030.
- Incremental climate change impacts are projected to add 125 GWh and 85 GWh to annual consumption and 80 MW and 60 MW to peak demand by 2030 in the high and mid demand cases, respectively.
- Traditional AAEE, additional SB 350 savings, and AAPV reduce sales by 3,650 GWh and net peak demand by 1050 MW in the mid demand case by 2030.

Electricity Consumption and Sales

The *CED 2017 Revised* high, mid, and low demand case results for baseline electricity consumption are shown in **Figure 59**, along with the mid case from *CEDU 2016*. Unlike the IOU planning areas, additional efficiency programs for 2016 and 2017 do not push consumption down below *CEDU 2016* at the beginning of the forecast period, as efficiency program efforts are not as intensive. Higher EV and manufacturing sector forecasts push average annual growth in consumption in the new mid case above that in *CEDU 2016*, which tracks closer to the new low demand case. Annual growth from 2016 — 2027 for the *CED 2017 Revised* forecast averages 1.95 percent, 1.56 percent, and 1.28 percent in the high, mid and low cases, respectively, compared to 1.33 percent in the *CEDU 2016* mid case.

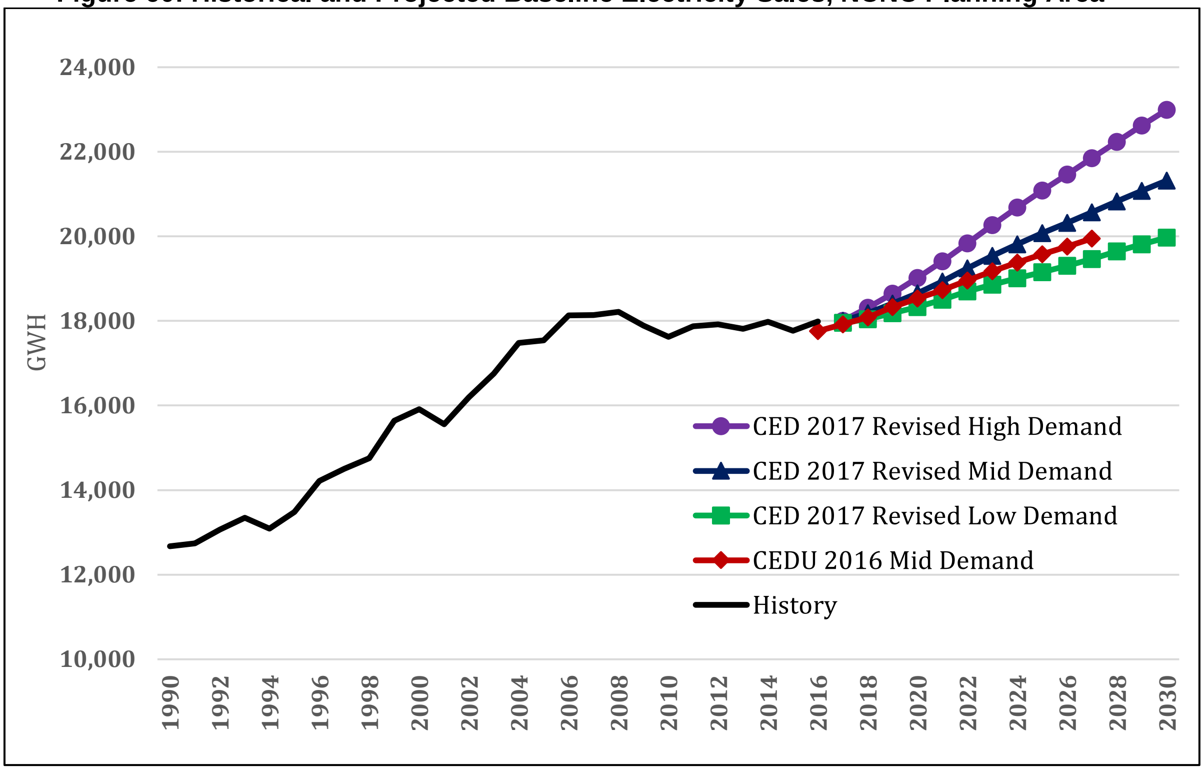
Projected electricity sales for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case for NCNC are shown in **Figure 60**. The relative increase in PV generation for NCNC is much smaller compared to *CEDU 2016* than for the IOU planning areas, so sales in the new mid case are above *CEDU 2016* mid throughout the forecast, growing at a faster rate along with consumption. Annual growth from 2016 — 2027 for the *CED 2017 Revised* forecast averages 1.78 percent, 1.23 percent, and 0.72 percent in the high, mid and low cases, respectively, compared to 1.06 percent in the *CEDU 2016* mid case.

Figure 59: Historical and Projected Baseline Consumption, NCNC Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 60: Historical and Projected Baseline Electricity Sales, NCNC Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

The demand forms accompanying this report[87] provide baseline results for consumption and sales by the three forecast zones within the NCNC planning area. With the fastest growth in per capita income and a relatively high proportion of EVs (thus a higher EV forecast), Forecast Zone 13 (SMUD service territory) shows the fastest growth in consumption and sales over 2016-2030.

Table 43 shows the traditional AAEE, additional SB 350, and AAPV consumption savings estimated for NCNC by scenario. By 2030, savings from these three sources combined reach about 3,000 GWh, 3,650 GWh, and 4,100 GWh in the high-low, mid-mid, and low-high scenarios, respectively.

Table 43: Traditional AAEE, SB 350, and AAPV Consumption Savings by Scenario (GWh), NCNC

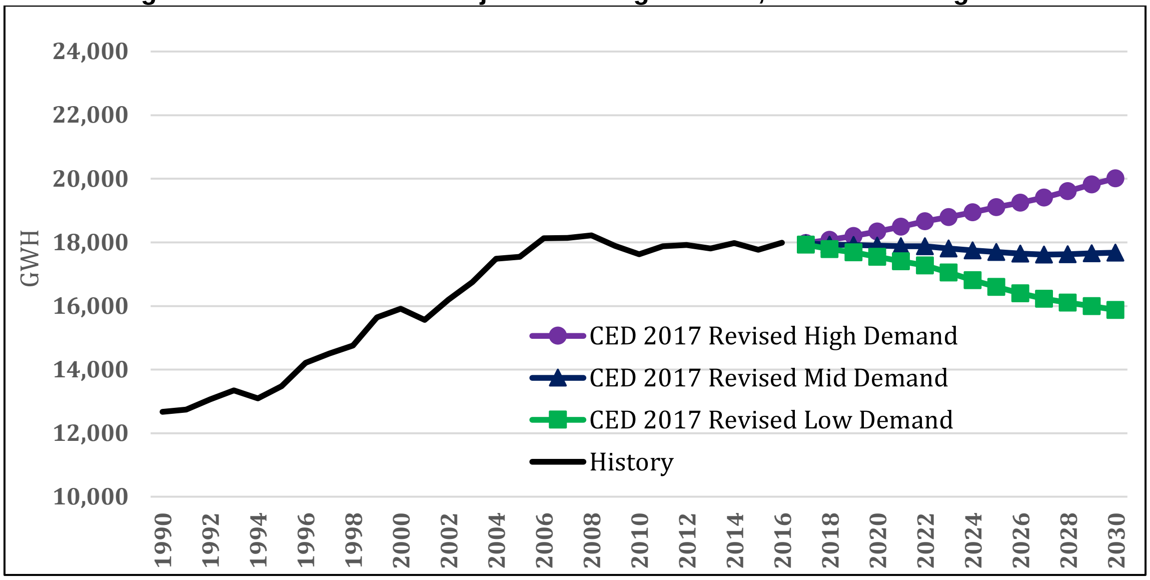
	High-Low			Mid-Mid			Low-High		
	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV
2017	13	14		16	14		16	14	
2018	207	27		226	27		230	27	
2019	420	30		459	30		469	30	
2020	626	31	18	695	42	19	714	42	20
2021	838	30	52	955	52	54	986	55	56
2022	1,056	29	88	1,219	63	91	1,265	69	94
2023	1,313	29	125	1,535	74	128	1,598	82	131
2024	1,544	28	161	1,821	84	165	1,899	124	168
2025	1,758	26	198	2,087	94	201	2,184	167	205
2026	1,956	25	234	2,334	104	238	2,450	214	242
2027	2,137	24	270	2,563	114	274	2,698	261	278
2028	2,297	23	304	2,762	125	309	2,915	308	314
2029	2,439	23	338	2,942	136	343	3,110	362	348
2030	2,585	23	371	3,123	147	376	3,305	412	381

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 61 shows the managed sales forecasts for NCNC after adjusting for these three savings sources. The managed mid demand case is flat while sales in the low case declines throughout the forecast period. Annual growth from 2016 — 2030 averages 0.77 percent, -0.13 percent, and -0.89 percent in the high, mid, and low cases, respectively.

87 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

Figure 61: Historical and Projected Managed Sales, NCNC Planning Area

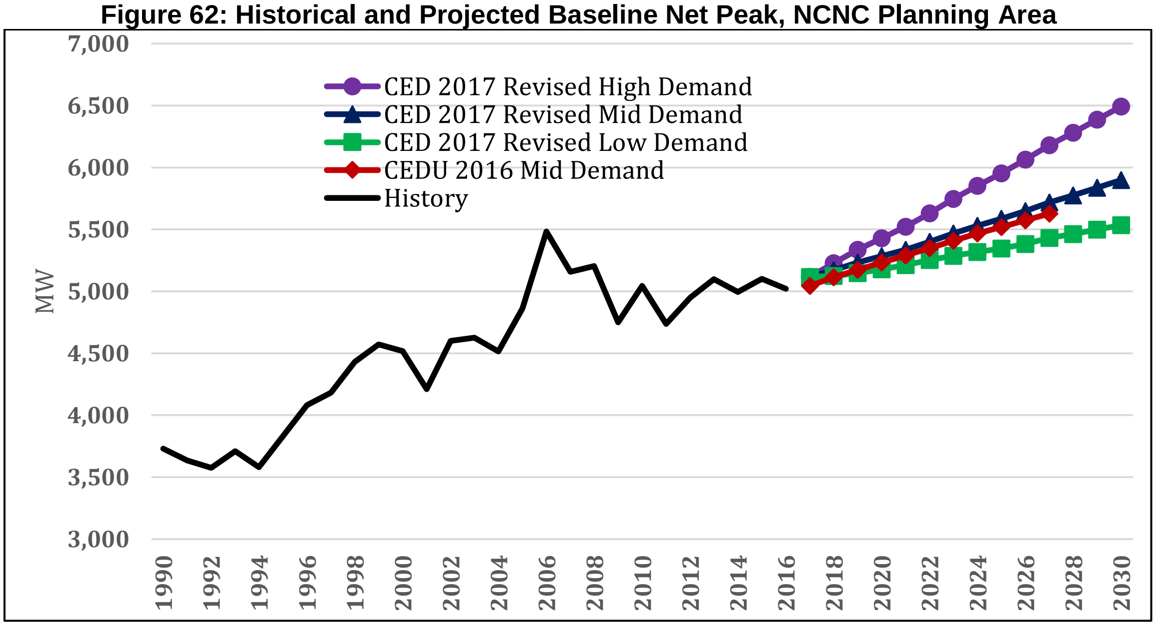


Source: California Energy Commission, Energy Assessments Division, 2017.

Peak Demand

Projected baseline net peak for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case for the NCNC planning area is shown in **Figure 62**. From 2017 onward, the new mid case grows at about the same rate as *CEDU 2016*. Peak demand in all three *CED 2017 Revised* cases grows more slowly during this period than the sales counterparts since EV demand at peak is relatively less important than annual EV consumption. Annual growth from 2017 — 2027 for the *CED 2017 Revised* forecast averages 1.91 percent, 1.12 percent, and 0.60 percent in the high, mid, and low cases, respectively, compared to 1.10 percent in the *CEDU 2016* mid case.

Figure 62: Historical and Projected Baseline Net Peak, NCNC Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 44 shows the traditional AAEE, additional SB 350 and AAPV peak demand savings estimated for NCNC by scenario. Peak savings do not incorporate any peak shift. By 2030, savings from these three sources combined reach about 700 MW, 1050 MW, and 1,200 MW in the high-low, mid-mid, and low-high scenarios, respectively.

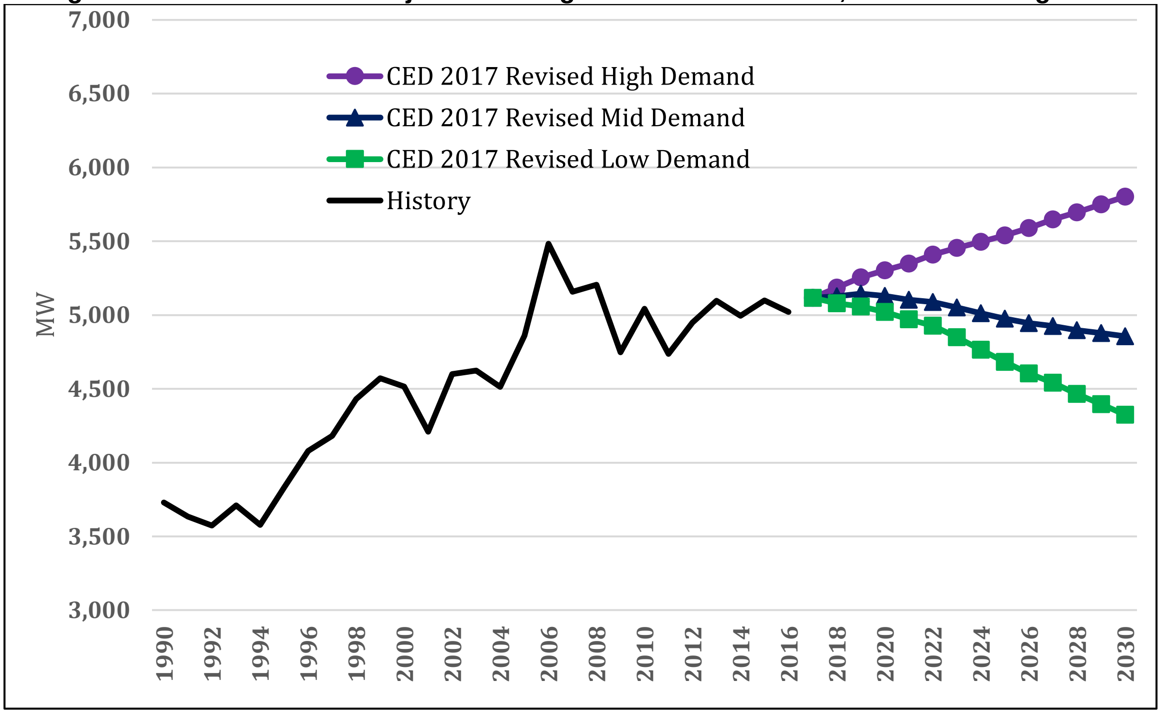
Applying these savings to the appropriate baseline forecast cases yields the managed net peak forecasts shown in **Figure 63**. The high demand case retains an upward trend (at about the same rate as the mid baseline case), the managed mid case drops slightly, and the low case drops steeply throughout the forecast period. Annual growth from 2017–2030 for the *CED 2017 Revised* forecast averages 0.96 percent, -0.41 percent, and -1.43 percent in the high, mid, and low cases, respectively.

Table 44: Traditional AAEE, SB 350, and AAPV Peak Savings by Scenario (MW), NCNC

	High-Low			Mid-Mid			Low-High		
	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV
2017	3	4	-	3	4	-	3	4	-
2018	39	7	-	43	7	-	44	7	-
2019	80	8	-	88	8	-	90	8	-
2020	120	8	4	139	16	4	143	16	4
2021	160	8	11	204	24	12	211	24	12
2022	201	8	19	268	31	20	280	33	20
2023	263	8	27	358	39	27	376	41	28
2024	319	7	34	442	46	35	466	57	36
2025	372	7	42	521	54	43	554	75	44
2026	424	7	50	598	61	51	639	94	51
2027	473	6	57	672	69	58	723	114	59
2028	520	6	65	743	77	66	802	134	67
2029	565	6	72	810	84	73	878	158	74
2030	611	6	79	878	92	80	954	180	81
NOTE: Includes Line Losses									

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 63: Historical and Projected Managed Net Peak Demand, NCNC Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

LADWP Planning Area

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

Key factors incorporated in the forecast include the following:

- Projected population growth averages 0.50 percent per year over 2016-2030, lower than the average for the state as a whole (0.81 percent) and lowest of any planning area except for BUGL. Projected growth in the number of households in the mid case averages 0.73 percent per year, also lower than the state average (0.94 percent).
- Per capita income growth averages 2.26 percent per year from 2016-2030, higher than the state average (1.88 percent).
- EV electricity consumption by 2030 is projected to be about 2,000 GWh, 1,800 GWh, and 1,300 GWh in the high, mid, and low demand cases, respectively.
- Additional electrification adds 260 GWh, 150 GWh, and 90 GWh to consumption in the high, mid, and low cases, respectively, by 2030.
- Projected behind-the-meter PV installed capacity reaches 520 MW, 650 MW, and 770 MW in the high, mid, and low demand cases, respectively, by 2030.

- Incremental climate change impacts are projected to add 180 GWh and 180 GWh to annual consumption and 125 MW and 70 MW to peak demand by 2030 in the high and mid demand cases, respectively.
- Traditional AAEE, additional SB 350 savings, and AAPV reduce sales by 6,000 GWh and net peak demand by 1,500 MW in the mid demand case by 2030.

Electricity Consumption and Sales

The *CED 2017 Revised* high, mid, and low demand case results for baseline electricity consumption are shown in **Figure 64**, along with the mid case from *CEDU 2016*. As *CEDU 2016* projections overstate consumption in 2016, the three new cases begin the forecast period below the *CEDU 2016* mid case. A higher EV forecast pushes average annual growth in consumption in the new mid case above that in *CEDU 2016*, although growth is tempered by lower population projections for Los Angeles County. The net result is almost identical consumption in 2027 for the two mid cases. Annual growth from 2016 — 2027 for the *CED 2017 Revised* forecast averages 1.58 percent, 1.21 percent, and 0.83 percent in the high, mid and low cases, respectively, compared to 1.02 percent in the *CEDU 2016* mid case.

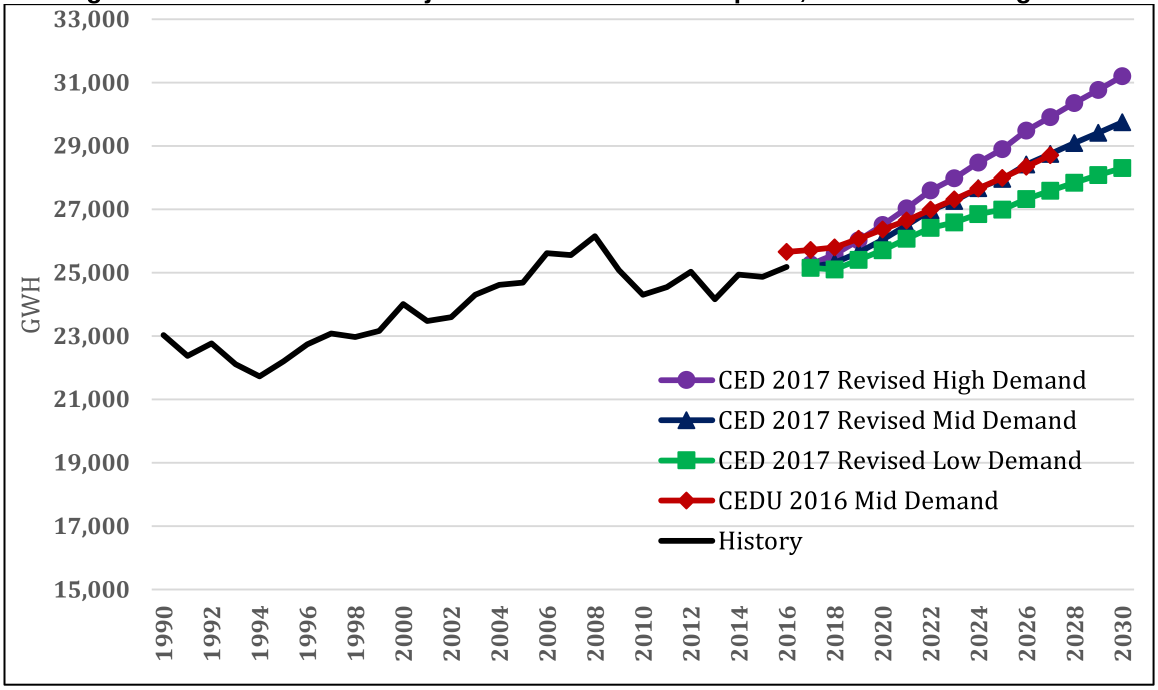
Projected electricity sales for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case for the LADWP planning area are shown in **Figure 65**. All four cases show a dip or flattening at the beginning of the forecast period as significantly more non-PV self-generation was added in 2017. From 2018 onward, sales growth is faster in the new mid case compared to *CEDU 2016*, fueled by faster consumption growth. Annual growth from 2016-2027 for the *CED 2017 Revised* forecast averages 1.33 percent, 0.87 percent, and 0.38 percent in the high, mid, and low cases, respectively, compared to 0.73 percent in the *CEDU 2016* mid case.

The demand forms accompanying this report[88] provide baseline results for consumption and sales by the two forecast zones within the LADWP planning area. Population and employment in Forecast Zone 17 (inland Los Angeles) are expected to grow faster than in Forecast Zone 16 (coastal Los Angeles), yielding faster growth in electricity consumption and sales.

Table 45 shows the traditional AAEE, additional SB 350, and AAPV consumption savings estimated for LADWP by scenario. By 2030, savings from these three sources combined reach about 5,300 GWh, 6,000 GWh, and 6,500 GWh in the high-low, mid-mid, and low-high scenarios, respectively.

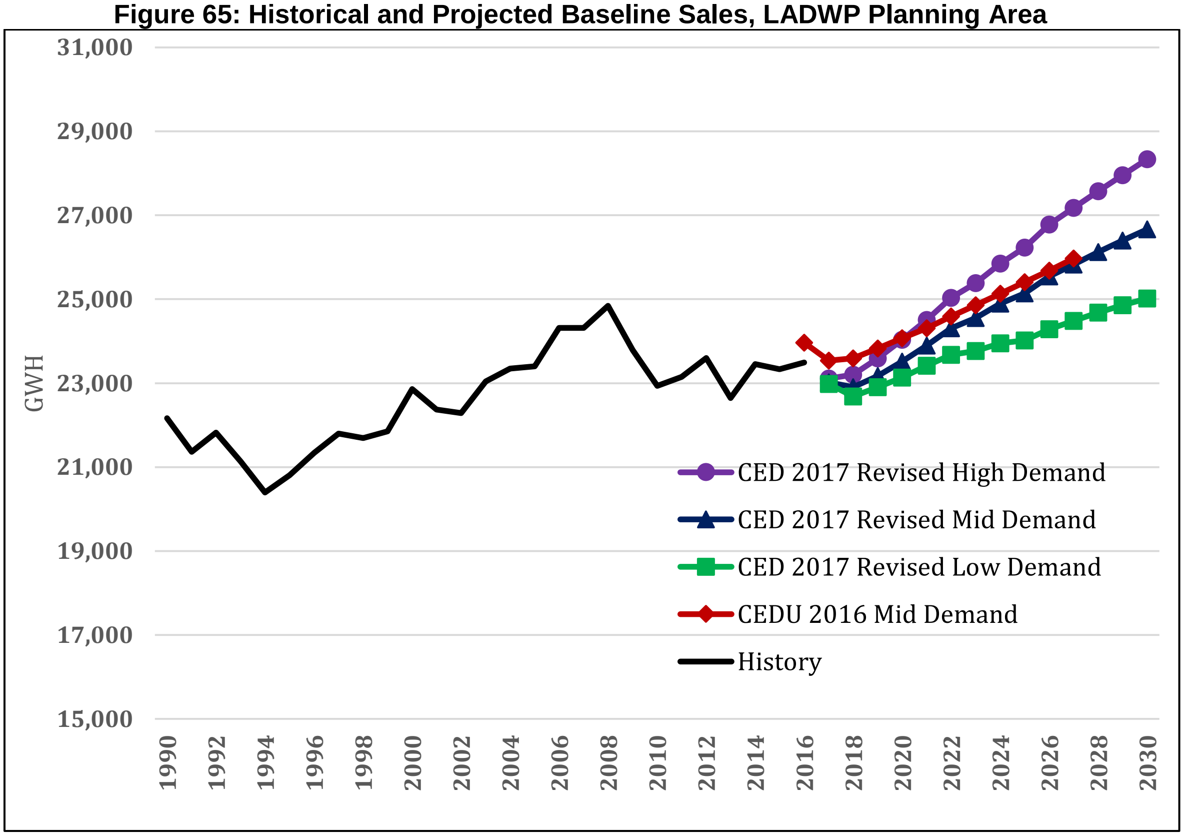
88 http://www.energy.ca.gov/2017_energypolicy/documents/#02212018

Figure 64: Historical and Projected Baseline Consumption, LADWP Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 65: Historical and Projected Baseline Sales, LADWP Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 45: Traditional AAEE, SB 350, and AAPV Consumption Savings by Scenario (GWh), LADWP

	High-Low			Mid-Mid			Low-High		
	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV
2017	13	15		17	15		17	15	
2018	401	29		421	29		425	29	
2019	816	32		858	32		868	32	
2020	1,192	32	13	1,265	44	14	1,285	44	16
2021	1,563	31	35	1,686	55	39	1,718	58	42
2022	1,926	31	56	2,098	67	61	2,145	72	66
2023	2,338	30	78	2,571	77	84	2,637	86	90
2024	2,739	29	98	3,030	88	105	3,113	130	113
2025	3,145	28	119	3,491	99	127	3,593	176	135
2026	3,549	26	139	3,947	109	149	4,069	225	158
2027	3,939	25	159	4,386	120	170	4,529	274	180
2028	4,316	24	178	4,806	131	190	4,966	324	202
2029	4,681	24	197	5,210	143	210	5,386	380	224
2030	5,072	24	216	5,638	154	230	5,830	434	245

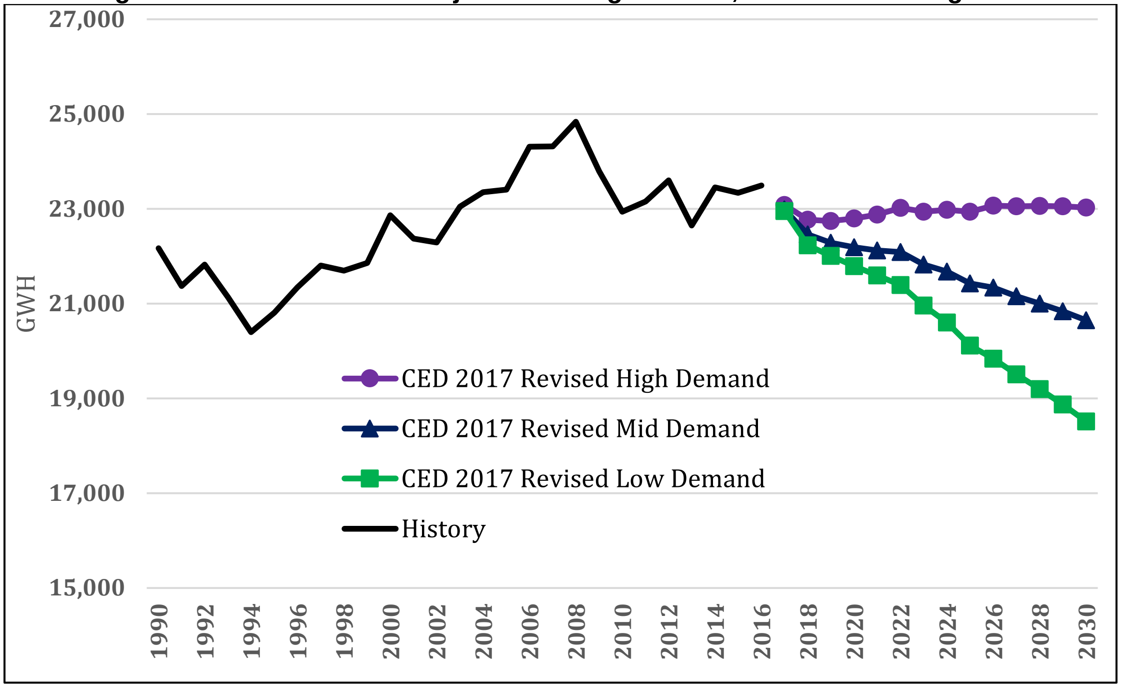
Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 66 shows the managed sales forecasts for LADWP after adjusting for these three savings sources. The managed high demand case is flat while sales in the other cases decline throughout the forecast period, reflecting the aggressiveness of LADWP efficiency goals. Annual growth from 2016 — 2030 averages -0.14 percent, -0.92 percent, and -1.69 percent in the high, mid, and low cases, respectively.

Peak Demand

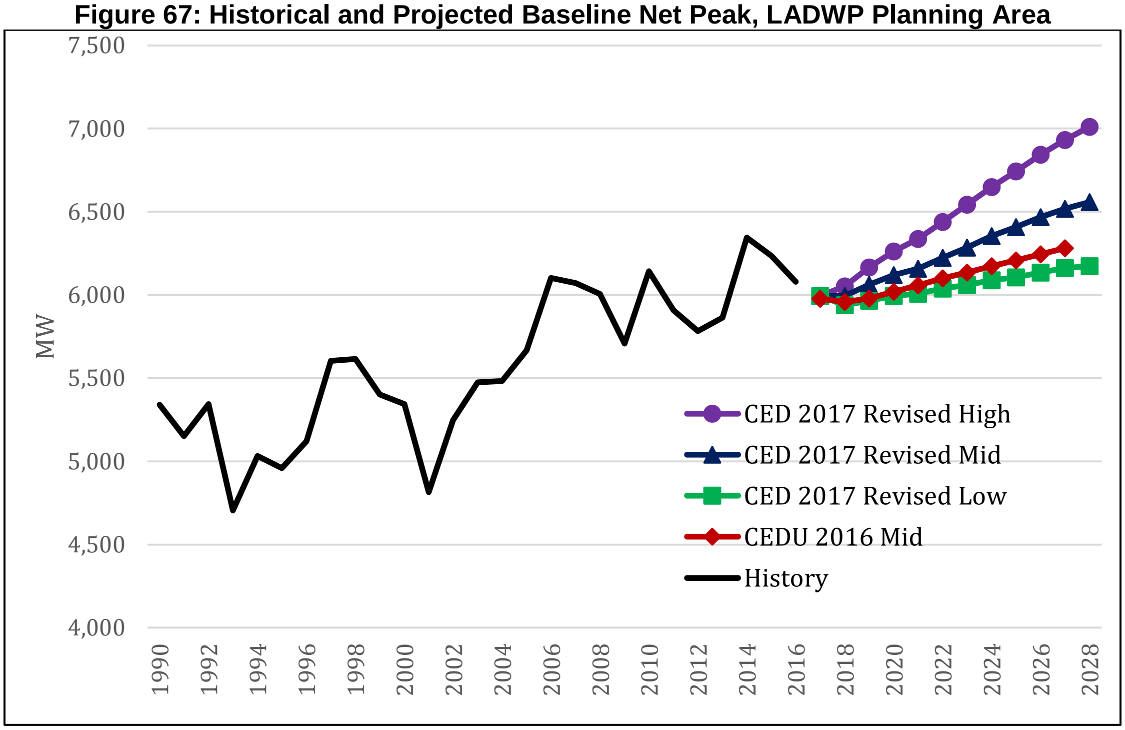
Projected baseline net peak for the three *CED 2017 Revised* cases and the *CEDU 2016* mid demand case for the LADWP planning area is shown in **Figure 67**. From 2017 onward, the new mid case grows faster than *CEDU 2016*, reflecting faster growth in sales. Peak demand in all three *CED 2017 Revised* cases grows more slowly during this period than the sales counterparts since EV demand at peak is relatively less important than annual EV consumption. Annual growth from 2017 — 2027 for the *CED 2017 Revised* forecast averages 1.46 percent, 0.84 percent, and 0.27 percent in the high, mid, and low cases, respectively, compared to 0.50 percent in the *CEDU 2016* mid case.

Figure 66: Historical and Projected Managed Sales, LADWP Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 67: Historical and Projected Baseline Net Peak, LADWP Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

Table 46 shows the traditional AAEE, additional SB 350 and AAPV peak demand savings estimated for LADWP by scenario. As with NCNC, peak savings do not incorporate any peak shift. By 2030, savings from these three sources combined reach about 1,100 MW, 1,500 GWh, and 1,700 GWh in the high-low, mid-mid, and low-high scenarios, respectively.

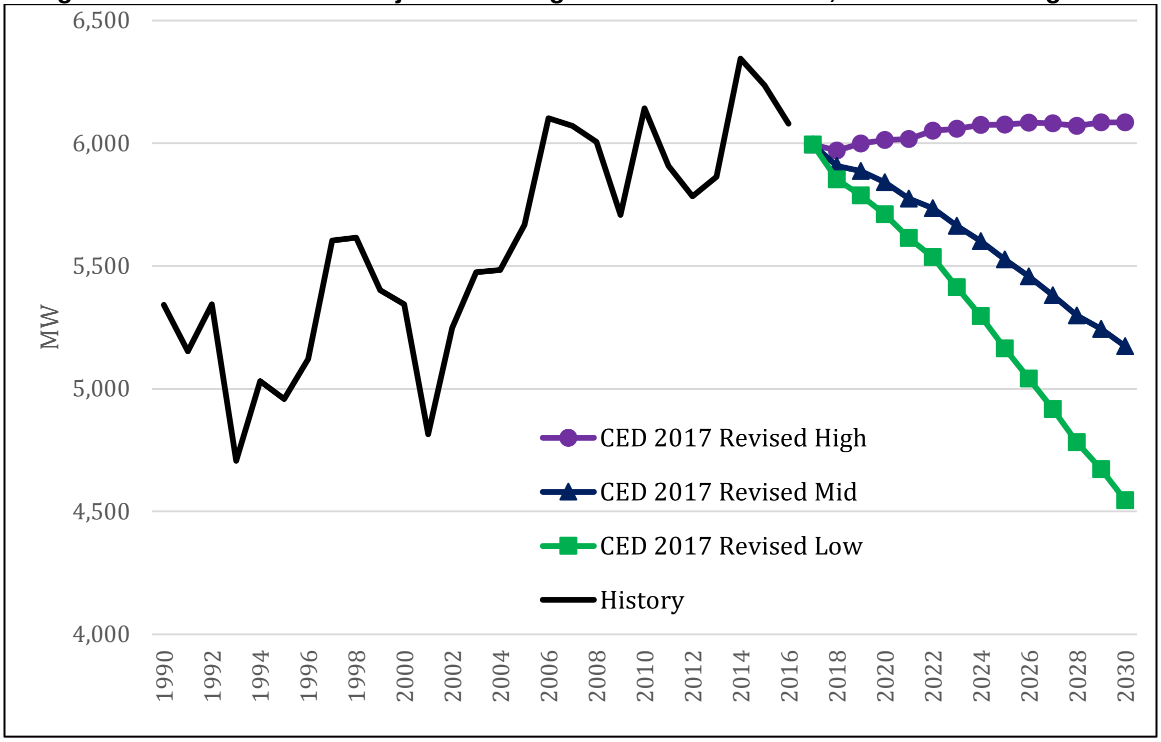
Applying these savings to the appropriate baseline forecast cases yields the managed net peak forecasts shown in **Figure 68**. The high demand case retains an upward trend while the other two cases drop steeply throughout the forecast period. Annual growth from 2017 — 2030 for the *CED 2017 Revised* forecast averages 0.11 percent, -1.13 percent, and -2.11 percent in the high, mid, and low cases, respectively.

Table 46: Traditional AAEE, SB 350, and AAPV Peak Savings by Scenario (MW), LADWP

	High-Low			Mid-Mid			Low-High		
	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV	Trad. AAEE	SB 350 Savings	AAPV
2017	3	4	-	4	4	-	4	4	-
2018	81	8	-	86	8	-	87	8	-
2019	166	9	-	175	9	-	177	9	-
2020	243	9	5	265	17	5	269	17	6
2021	307	9	11	354	26	12	363	26	13
2022	371	9	17	443	34	18	456	35	20
2023	460	8	23	563	42	25	583	44	27
2024	545	8	29	678	50	31	705	62	33
2025	632	8	35	794	59	37	829	81	40
2026	718	7	41	908	67	43	953	102	46
2027	804	7	46	1,021	75	49	1,076	124	52
2028	888	7	52	1,130	83	55	1,195	146	59
2029	971	7	57	1,238	92	61	1,311	172	65
2030	1,059	7	62	1,349	100	67	1,432	196	71
NOTE: Includes Line Losses									

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 68: Historical and Projected Managed Net Peak Demand, LADWP Planning Area



Source: California Energy Commission, Energy Assessments Division, 2017.

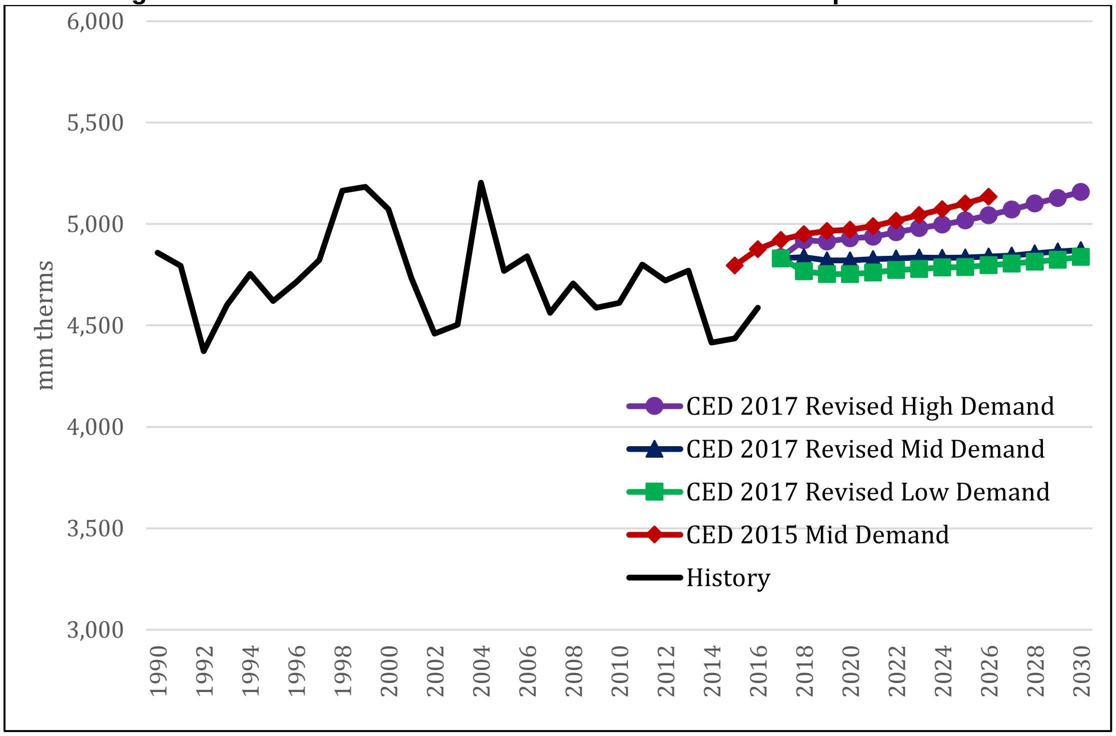
PG&E Natural Gas Planning Area

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

Figure 69 shows the three *CED 2017 Revised* baseline cases and the *CED 2015* mid baseline demand case. The projected jump in consumption in 2017 is noticeable, as the adjustment for average weather for the forecast period increases consumption by around 320 mm therms. The graph also shows the effect of climate change impacts, as the low demand case (with no climate change) almost overtakes the mid case by the end of the forecast period. Annual growth from 2016 — 2026 for the *CED 2017 Revised* forecast averages 0.94 percent, 0.54 percent, and 0.45 percent in the high, mid, and low cases, respectively, compared to 0.52 percent in the *CED 2015* mid case. From 2017 onward, the new mid case is flatter than *CED 2015* since it includes the impacts of the 2016 Title 24 building standards update, has a lower forecast for natural gas vehicles, and has slightly lower projected population growth.

Table 47 shows AAEE natural gas savings for PG&E by scenario. Note that additional SB 350 savings were not estimated for natural gas. Applying these scenarios to the appropriate baseline demand case gives **Figure 70**, the managed natural gas consumption forecast. Consumption in the managed mid and low demand cases decline throughout the forecast period. Growth from 2017 onward in the high demand case falls by around one-third. Annual growth from 2016 — 2030 for the *CED 2017 Revised* managed forecast averages 0.63 percent, 0.03 percent, and -0.08 percent in the high, mid, and low cases, respectively.

Figure 69: PG&E Baseline End-User Natural Gas Consumption Demand



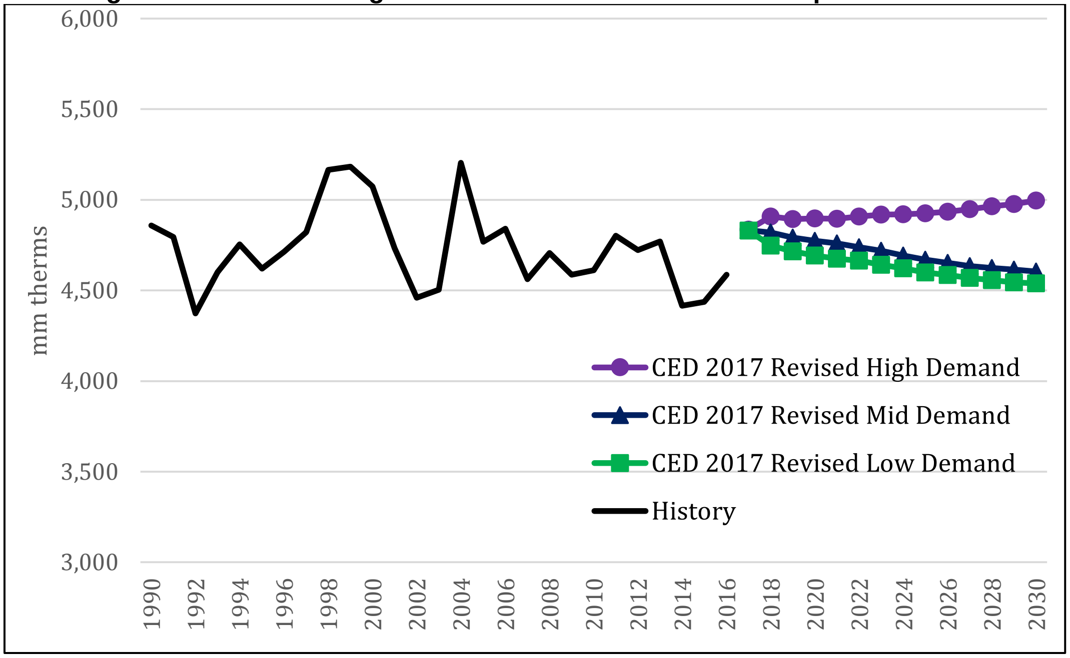
Source: California Energy Commission, Energy Assessments Division, 2017.

Table 47: PG&E AAEE Savings (mm Therms) by Scenario

	High-Low	Mid-Mid	Low-High
2017	0	0	0
2018	12	16	19
2019	21	30	37
2020	31	47	60
2021	42	68	85
2022	52	91	111
2023	63	116	137
2024	78	141	164
2025	93	165	188
2026	108	188	211
2027	123	211	235
2028	137	231	259
2029	151	249	279
2030	163	268	299

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 70: PG&E Managed End-User Natural Gas Consumption Demand



Source: California Energy Commission, Energy Assessments Division, 2017.

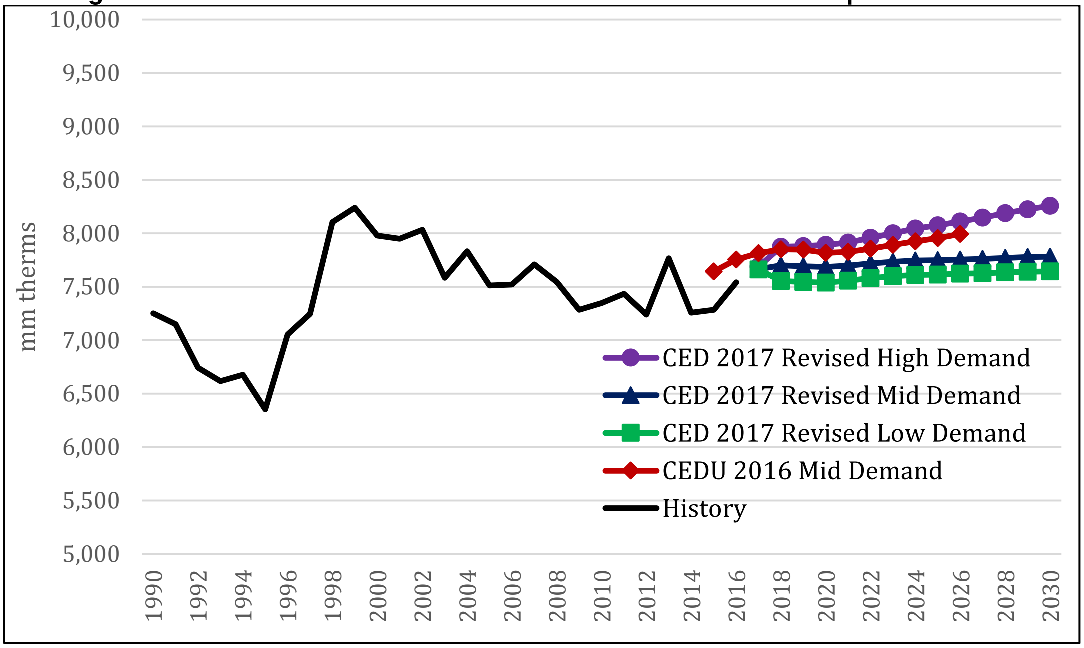
SoCal Gas Planning Area

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

Figure 71 shows the three *CED 2017 Revised* baseline cases and the *CED 2015* mid demand baseline case. As with PG&E, negative climate change impacts reduce the growth rate in the mid demand case versus the low. Consumption jumps in 2017 as the adjustment for average weather for the forecast period increases consumption by around 260 mm therms. Annual growth from 2016 — 2026 for the *CED 2017 Revised* forecast averages 0.73 percent, 0.28 percent, and 0.11 percent in the high, mid, and low cases, respectively, compared to 0.30 percent in the *CED 2015* mid case. The impacts of the 2016 Title 24 building standards update, a lower forecast for natural gas vehicles, and slightly lower projected population growth flatten growth in the new mid case relative to *CED 2015* from 2017 onward.

Table 48 shows AAEE natural gas savings for SoCal Gas by scenario. Applying these scenarios to the appropriate baseline demand case gives **Figure 72**, the managed natural gas consumption forecast. Consumption in the managed mid demand case declines after 2018 and low demand case consumption declines throughout the forecast period. Growth from 2017 onward in the high demand case falls by almost 50 percent. Annual growth from 2016 — 2030 for the *CED 2017 Revised* managed forecast averages 0.47 percent, -0.10 percent, and -0.26 percent in the high, mid, and low cases, respectively.

Figure 71: SoCal Gas Baseline End-User Natural Gas Consumption Demand



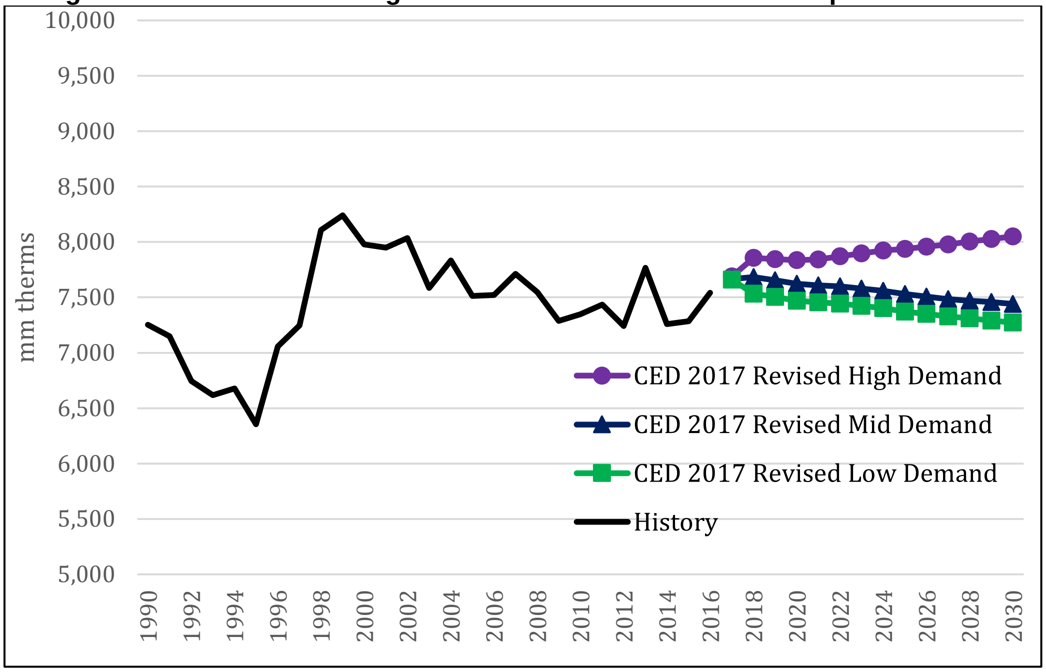
Source: California Energy Commission, Energy Assessments Division, 2017.

Table 48: SoCal Gas AAEE Savings (mm Therms) by Scenario

	High-Low	Mid-Mid	Low-High
2017	0	0	0
2018	19	20	21
2019	37	39	42
2020	56	64	70
2021	72	93	104
2022	88	122	139
2023	106	156	175
2024	122	188	210
2025	139	219	243
2026	154	249	272
2027	170	277	299
2028	185	299	325
2029	198	320	349
2030	209	340	372

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 72: SoCal Gas Managed End-User Natural Gas Consumption Demand



Source: California Energy Commission, Energy Assessments Division, 2017.

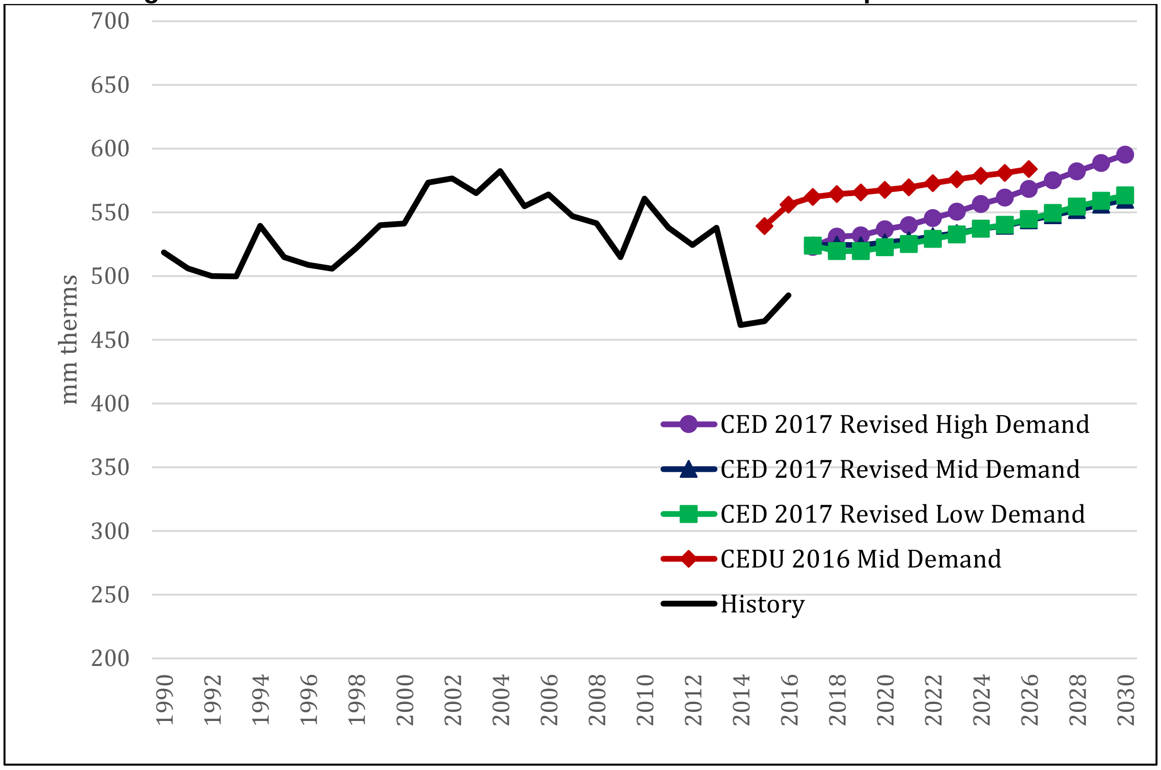
SDG&E Natural Gas Planning Area

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

Figure 73 shows the three *CED 2017 Revised* cases and the *CED 2015* mid demand case. For SDG&E, climate change impacts are sufficient to drop the mid case below the low by the end of the forecast period. Consumption jumps in 2017 as the adjustment for average weather for the forecast period increases consumption by around 70 mm therms. Annual growth from 2016–2026 for the *CED 2017 Revised* baseline forecast averages 1.60 percent, 1.15 percent, and 1.17 percent in the high, mid, and low cases, respectively, compared to 0.49 percent in the *CED 2015* mid case. Unlike PG&E and SoCal Gas, consumption growth in the new mid case roughly matches that in *CED 2015* from 2017 onward, reflecting higher projected population growth.

Table 49 shows AAEE natural gas savings for SDG&E. Applying these scenarios to the appropriate baseline demand case gives **Figure 74**, the managed natural gas consumption forecast. The mid and low demand cases become essentially flat from 2017 onward, while the high demand case, with significantly less AAEE savings attached, continues significant growth. Annual growth from 2016 — 2030 for the *CED 2017 Revised* managed forecast averages 1.34 percent, 0.64 percent, and 0.57 percent in the high, mid, and low cases, respectively.

Figure 73: SDG&E Baseline End-User Natural Gas Consumption Demand



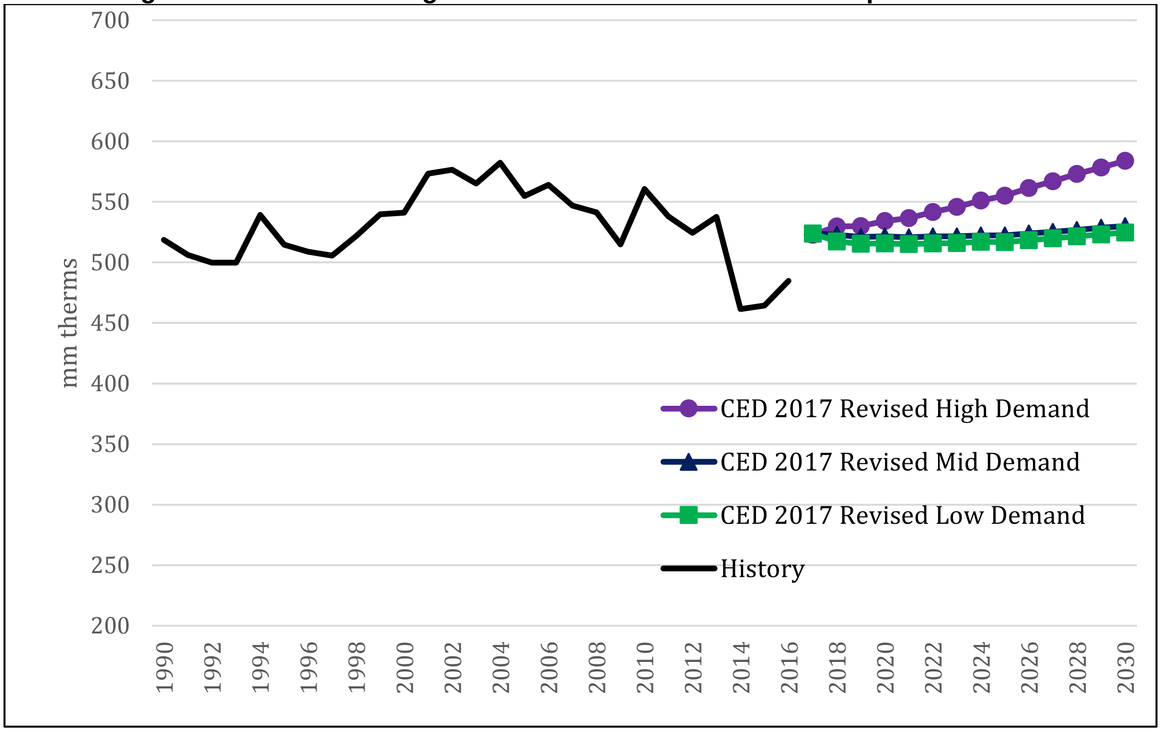
Source: California Energy Commission, Energy Assessments Division, 2017.

Table 49: SDG&E Natural Gas AAEE Savings (mm Therms) by Scenario

	High-Low	Mid-Mid	Low-High
2017	0	0	0
2018	1	2	2
2019	2	3	4
2020	3	5	7
2021	3	7	10
2022	4	9	13
2023	5	12	17
2024	5	15	20
2025	6	17	23
2026	7	20	26
2027	8	22	30
2028	9	25	33
2029	10	27	36
2030	11	30	39

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 74: SDG&E Managed End-User Natural Gas Consumption Demand



Source: California Energy Commission, Energy Assessments Division, 2017.

LIST OF ACRONYMS

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

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

APPENDIX A: Self-Generation Forecasts

Compiling Historical Distributed Generation Data

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

- New Solar Homes Partnership (NSHP)[89]
- Self-Generation Incentive Program (SGIP)[90]
- The California Solar Initiative[91]
- POU programs[92]
- Utility interconnection filing [93]
- Emerging Renewables Program (ERP)[94]

In addition, power plants with a generating capacity of at least 1 MW are required to submit fuel use and generation data to the Energy Commission under the Quarterly Fuel and Energy Report (QFER) Form 1304.[95] QFER data includes 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 collects information from the plant owner. Therefore, it is not possible to determine if a project from a DG incentive program is already reporting data to the Energy Commission under QFER. For example, the SGIP has 174 completed projects that are at least 1 MW and about 82 pending projects that are 1 MW or larger. Given the small number of DG projects meeting QFER's reporting size threshold, double-counting may not be significant but could become an issue as an increasing amount of large SGIP projects come online.

89 Program data received on September 12, 2017 from staff in the Energy Commission's Renewables Office.

90 Downloaded on September 29, 2017 from (http://www.cpuc.ca.gov/sgip/).

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

92 Program data submitted by POU's on July 2016 (http://www.energy.ca.gov/sb1/pou_reports/index.html).

93 *2017 Integrated Energy Policy Report* data request available at (https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-03).

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

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

QFER accounts for the majority of onsite generation in California with the representation of large industrial cogeneration facilities. With each forecast cycle, staff continues to refine QFER data to correct for mistakes in data collection and data entry. Because QFER data is 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 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 non-residential 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 19 demand forecasting climate zones based on utility and county information. These steps were used to process data from all incentive programs in varying degrees to account for program-specific information. For example, certain projects in the SGIP program have an IOU as the program administrator but are interconnected to a POU; these projects were mapped directly to forecasting zones. Finally, capacity and peak factors from DG evaluation reports and PV performance data supplied by the CPUC were used to estimate energy and peak impacts.[96] [97]

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.[98] Staff decided to not degrade output for non-PV technologies,

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96 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).

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

98 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.

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

Figure A-1 shows statewide energy use from PV and non-PV technologies. Historically, PV constituted a small share of total self-generation; however, PV generation begins to show a sharp increase as the CSI program started to gain momentum after 2007 and by 2016, PV accounted for over 38 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 2016, self-generation from the residential sector was estimated to be over 23 percent of the statewide total in 2016.

Figure A-2 shows PV self-generation by sector from 1995 to 2016. PV adoption is generally concentrated in the residential and commercial sectors.

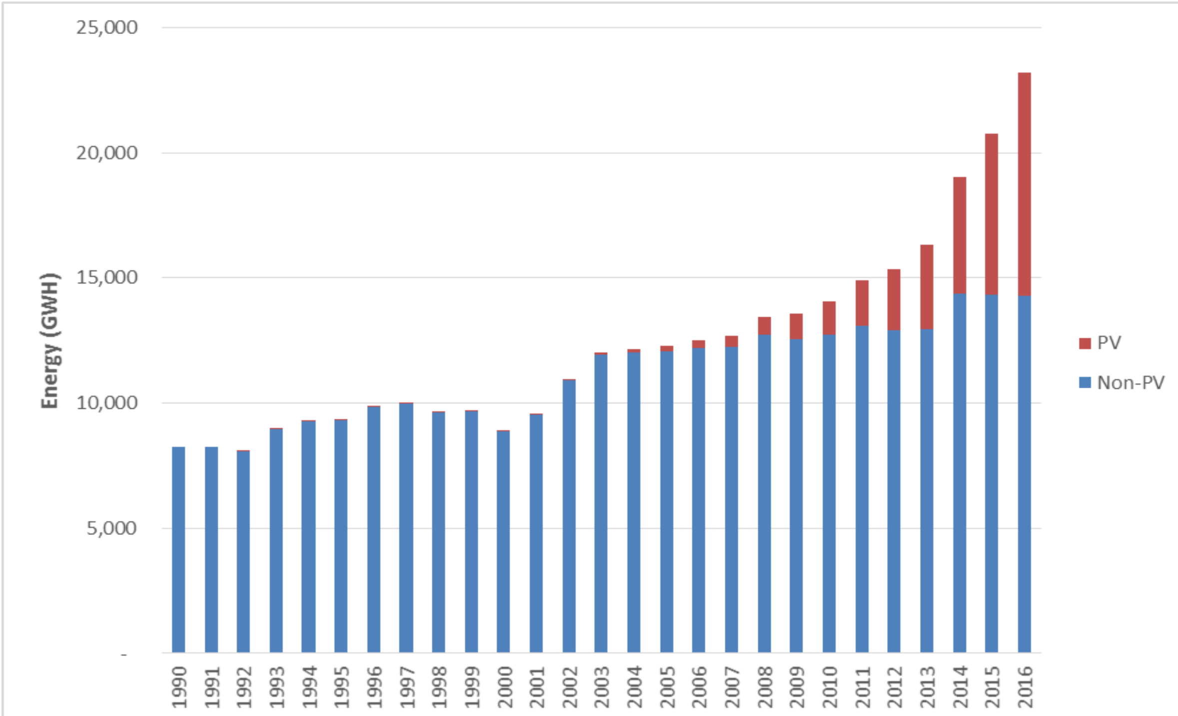
Figure A-3 shows the top 20 counties with PV by sector in 2015. PV capacity is led by Southern California with San Diego, Los Angeles, and Riverside counties making up the top 3 counties in the state with PV capacity.

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

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

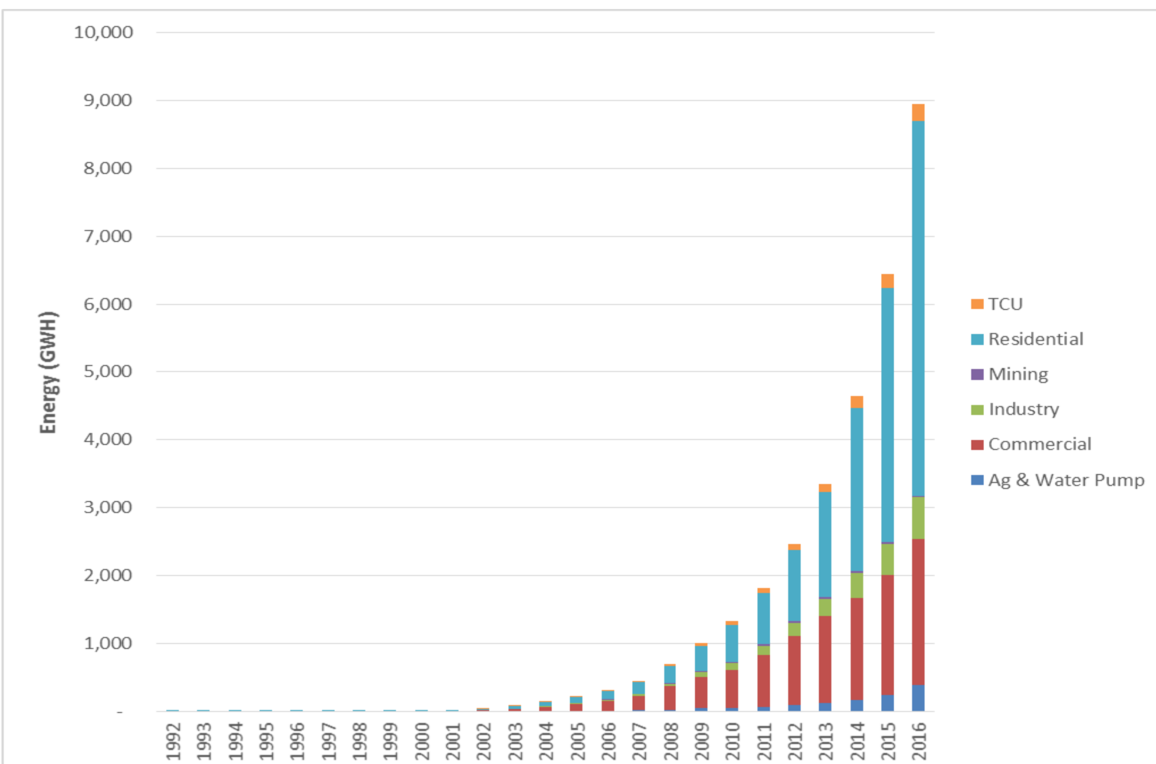
99 Navigant Consulting. April 2010. *Self-Generation Incentive Program Combined Heat and Power Performance Investigation.* Report available at (http://www.cpuc.ca.gov/NR/rdonlyres/594FEE2F-B37A-4F9D-B04A-B38A4DFBF689/0/SGIP_CHP_Performance_Investigation_FINAL_2010_04_01.pdf).

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



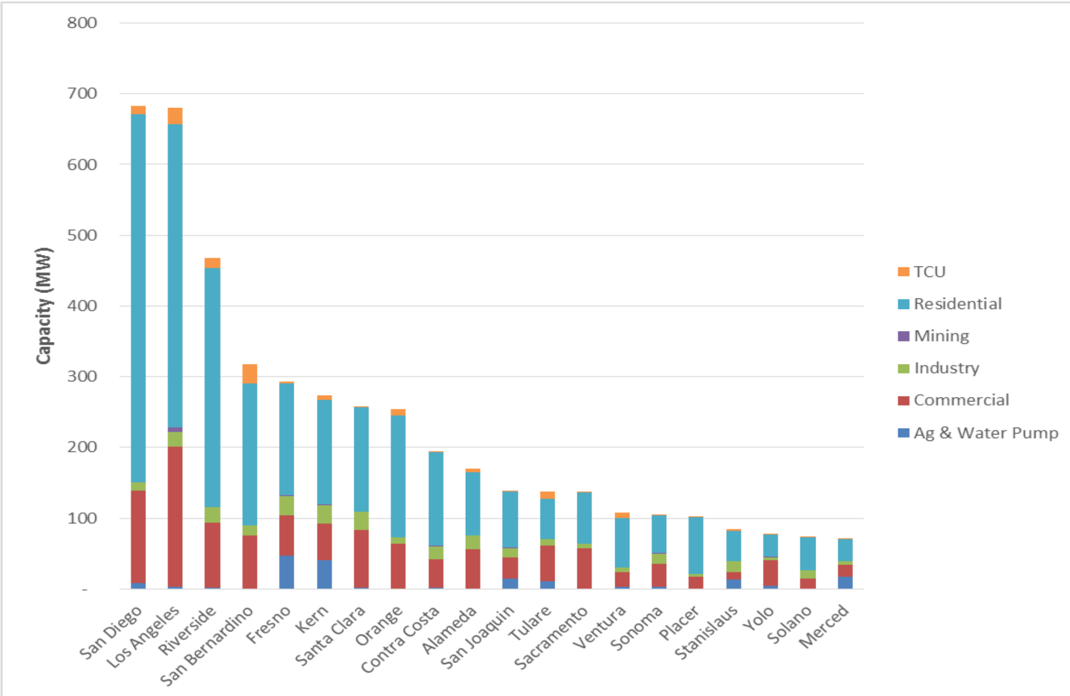
Source: California Energy Commission, Energy Assessments Division, 2017.

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



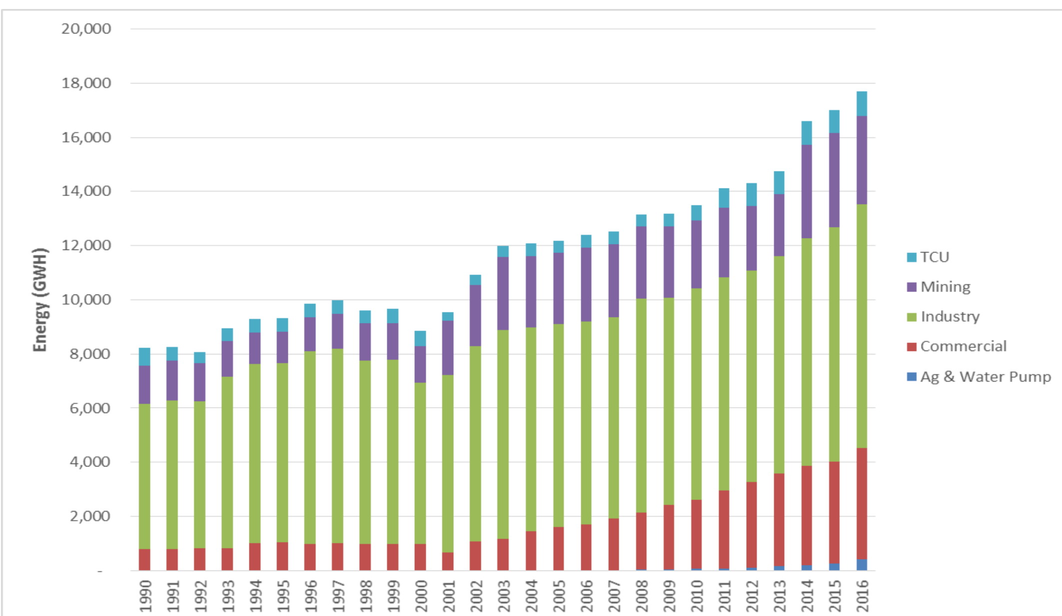
Source: California Energy Commission, Energy Assessments Division, 2017.

Figure A-3: Top 20 Counties With PV by Sector in 2016



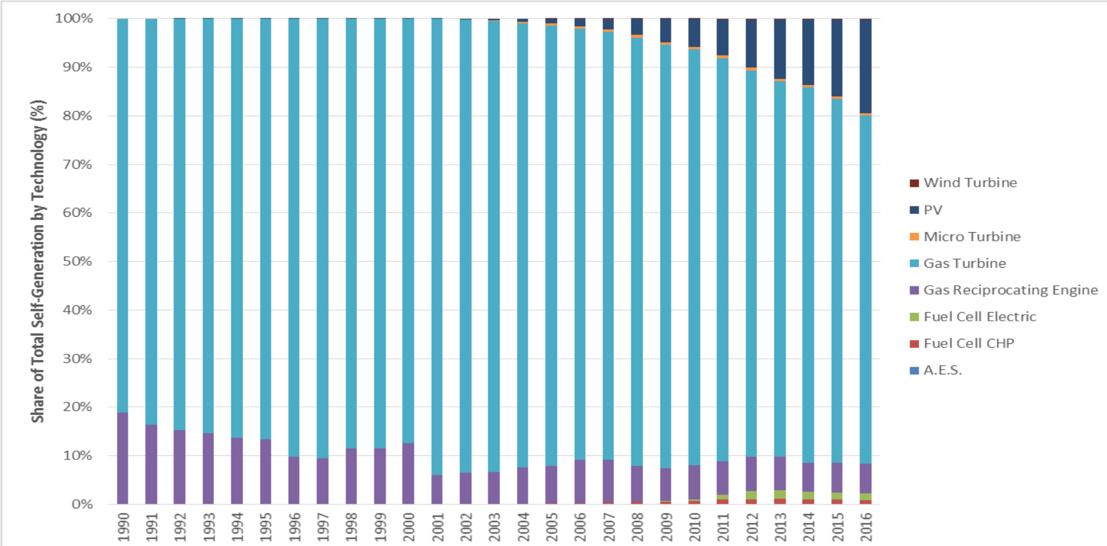
Source: California Energy Commission, Energy Assessments Division, 2017.

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



Source: California Energy Commission, Energy Assessments Division, 2017.

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



Source: California Energy Commission, Energy Assessments Division, 2017.

Residential Sector Predictive Model

The residential sector self-generation model was designed to forecast PV and SHW adoption based on considering a number of elements such as on fuel price, system cost, and performance assumptions. The model is similar in structure to the cash flow-based DG model in the National Energy Modeling System as used by the U.S. Energy Information Administration (EIA)[100] and the *SolarDS* model developed by the National Renewable Energy Laboratory (NREL).[101]

A number of changes to the residential sector model were made based on the need to account for the impact of net metering and the design of residential retail rates. Staff collected data on historical retail rates for the investor-owned utilities. Due to time constraints, staff will continue to use average sector rates as developed for *CED 2017 Preliminary* forecast for publically owned utilities.[102] Due to limited participation from the multifamily segment of the residential sector, staff limited its modeling of PV adoption to single family homes.[103]

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100 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).

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

102 Staff were able to incorporate retail rates for the Sacramento Municipal Utilities District.

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

PV cost and performance data were based on analysis performed by Energy and Environmental Economics (E3) for the CPUC.[104] [105] Historical PV price data was compiled from rebate program data and a comprehensive report from Lawrence Berkeley National Laboratory.[106] 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 approximately 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.[107] Adjustments were made for incentives offered by the appropriate utility to obtain the net cost.

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

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

105 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.

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

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

Table A-1: Residential TOU Rates

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

Source: California Energy Commission, Energy Assessments Division, 2017

Another change for *CED 2017 Preliminary* is concerned with valuation of excess production from a renewable resource such as PV relative to customer load. The CPUC issued a decision in late 2015 instituting modest reforms to NEM.[108] Staff incorporated several elements of the adopted NEM decision such as:

- Applying nonbypassable charges on delivered energy instead of net sales
- Applying a modest charge for interconnection
- Assuming new NEM customers will be on a TOU rate after an IOU reaches its NEM capacity limit[109]

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

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

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

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.[110] 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 in order to mitigate a perceived shift in cost from occurring by customers with PV to customers without PV. The Mid Demand case is similar to the High Demand scenario but does not include the $3/kW capacity charge. Bill savings, including NEM calculation, also incorporates data on annual electric consumption from the Energy Commission's 2009 Residential Appliance Saturation Survey (RASS) and residential load shape data submitted by utilities as part of the 2015 IEPR data request.[111] 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.[112]

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

Another change for *CED 2017 Preliminary* concerns PV system sizing. For *CED 2017 Preliminary*, staff added annual electric usage level as another variable to segment the residential sector for forecasting adoption of PV systems.[113] Staff let PV size vary such that the calculated system size was able to provide roughly 90 percent of annual electric usage. Further, staff in the Commission's Energy Efficiency division provided typical systems sizes for new construction. For PV systems, hourly generation over the life of the system was estimated based on data provided to staff by CPUC. For SHW systems, energy saved on an annual basis was used directly to estimate bill savings.

The different discounted cost and revenue streams were then combined into a final cash flow table so that the internal rate of return (IRR) and project payback could be calculated. Revenues include incentives, avoided purchase of electricity or natural gas

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

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

112 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).

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

from the grid, tax savings on loan interest, and depreciation benefits. Costs include loan repayment, annual maintenance and operation expense, and inverter replacement cost.

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.[114] 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 five 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.[115] Another change for *CED 2017 Revised* was to employ a different market share curve for IOUs and SMUD residential customers. The reason for using a new market share curve was based on stakeholder comments received in 2015 IEPR and 2016 IEPR Update.[116] [117] In general, comments from stakeholders suggested that adopters of PV may not respond as well to payback periods as much as they would to monthly bill savings motivated in part by innovative ownership models.[118] This alternative metric for estimating the market share curve, monthly bill savings, is currently used by NREL as part of their new PV adoption model dGen.[119] Staff found that monthly bill savings generally improved estimated adoption of PV systems in the historical period relative to using payback period for estimating the

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114 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.

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

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

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

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

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

market share curve. Further, for other utilities for which staff was using average sector rates developed for *CED 2017 Revised,* used an updated market share curve based on payback period from analysis in support of CPUC's NEM proceeding.[120]

For *CED 2017 Revised,* staff used monthly bill savings to forecast PV additions in the Low Demand scenario and the payback period in the High Demand scenario. The mean of PV additions between the two bookend cases was used for the Mid Demand scenario. Using different market share curves for the two bookend cases was another way to reflect uncertainty in adoption of PV. To estimate actual penetration, maximum market share was multiplied by an estimated adoption rate, calculated using a Bass Diffusion curve, to estimate annual PV and SHW adoption. The Bass Diffusion curve is often used to model adoption of new technologies and is part of a family of technology diffusion functions characterized as having an "S" shaped curve to reflect the different stages of the adoption process.

The adoption rate is given by the following equation:

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

The terms p and q represent the impact of early and late adopters of the technology, respectively. Staff used means values for p (0.03) and q (0.38), derived from a survey of empirical studies.[121]

Self-Generation Forecast, Non-residential Sectors

Commercial Combined Heat and Power and Photovoltaic Forecast

CED 2017 Revised continues to use the predictive model developed for the *2015 IEPR* demand forecast to model adoption of CHP and PV in the commercial sector. This model uses the same basic payback framework as in the residential predictive model. Staff began by allocating energy use to different building types using the 2006 Commercial End-Use Survey (CEUS).[122] 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.

120 See footnote 15

121 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.

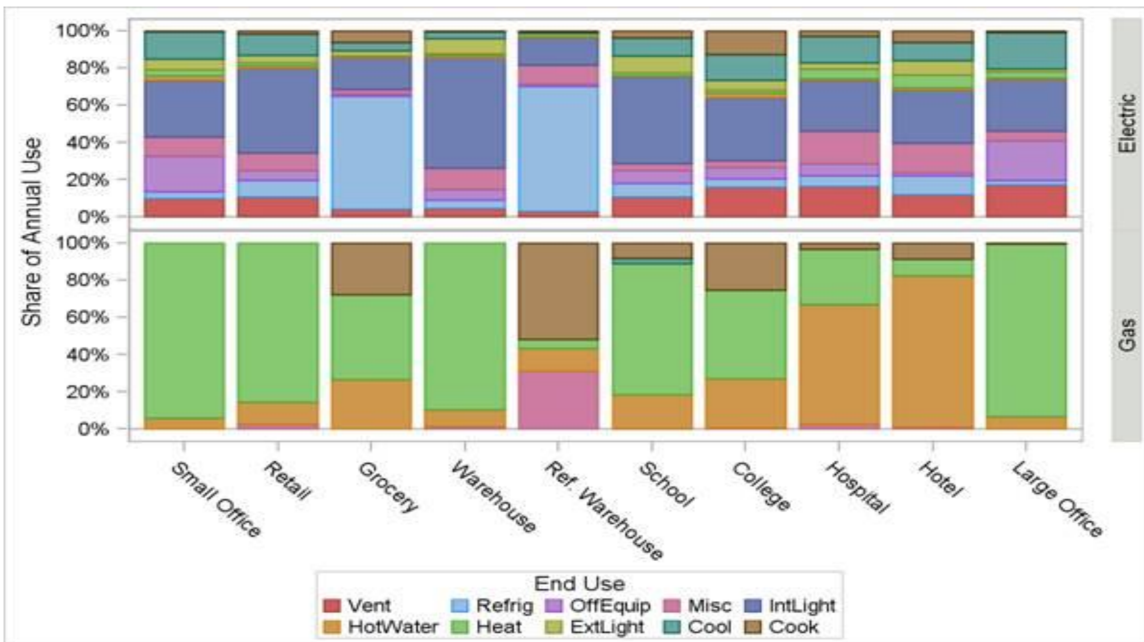
122 Itron. March 2006. Report available at (http://www.energy.ca.gov/2006publications/CEC-400-2006-005/CEC-400-2006-005.PDF).

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.

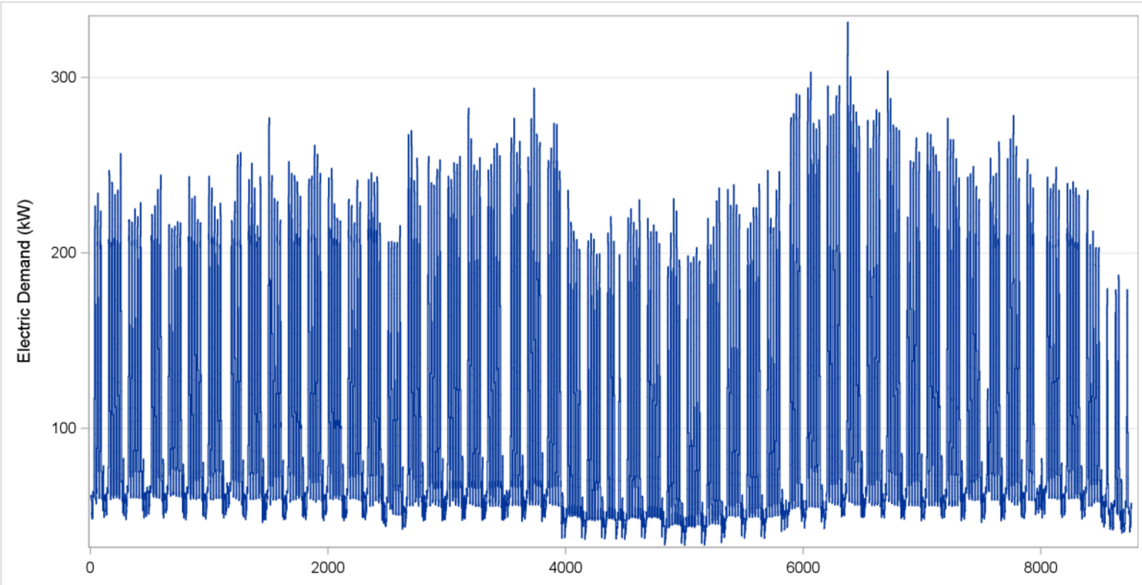
Staff grouped small and medium-size buildings together since the CEUS survey had a limited number of sample points for these building sizes. In addition, because of small sample sizes, staff grouped inland and coastal climate zones together. Four geographic profiles were created: north inland, north 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 A-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 A-7** shows hourly electricity loads for south coastal large schools.

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



Source: California Energy Commission, Energy Assessments Division, 2017.

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



*In chronological order (8760 annual hours).

Source: California Energy Commission, Energy Assessments Division, 2017.

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

For CHP, staff assumed that waste heat will be recovered to meet the site demand for hot water and space heating and that this will displace gas used for these two purposes.[123] 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.

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

Finally, cost and benefits were developed to derive payback. Staff applied the same set of assumptions used in a prior Energy Commission-sponsored report to characterize CHP technology operating characteristics such as heat rate, useful heat recovery, installed capital cost, and operating costs.[124] PV technology details such as installed cost and operating cost were based from the same E3 dataset used for the residential sector predictive model. Avoided retail electric and gas rates were derived from utility tariff sheets and based on estimated premise-level maximum demand. Current retail electric and gas rates were escalated based on the rates of growth for fuel prices developed for the *CED 2017 Preliminary*. In addition, CHP technologies may face additional costs such as standby and departing load charges. Details for these charges were also collected and used in the economic assessment. Staff examined details surrounding the applicability of these charges and applied them as appropriate.

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

Other Sector Self-Generation

Staff used a trend analysis for forecasting adoption of PV in the non-commercial/non-residential sectors. *CED 2017 Revised* continues to forecast energy storage systems based on a trend analysis approach similar to *CED 2017 Preliminary*. Data on energy storage projects from the SGIP rebate program was 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 2018 subject to funding availability.

Statewide Modeling Results

The following figures show results prepared for *CED 2017 Revised* by demand case. **Figure A-8** shows the PV generation, which reaches over 33,000 GWH in the Mid Demand case and nearly 47,000 GWH in the Low Demand case by 2030.

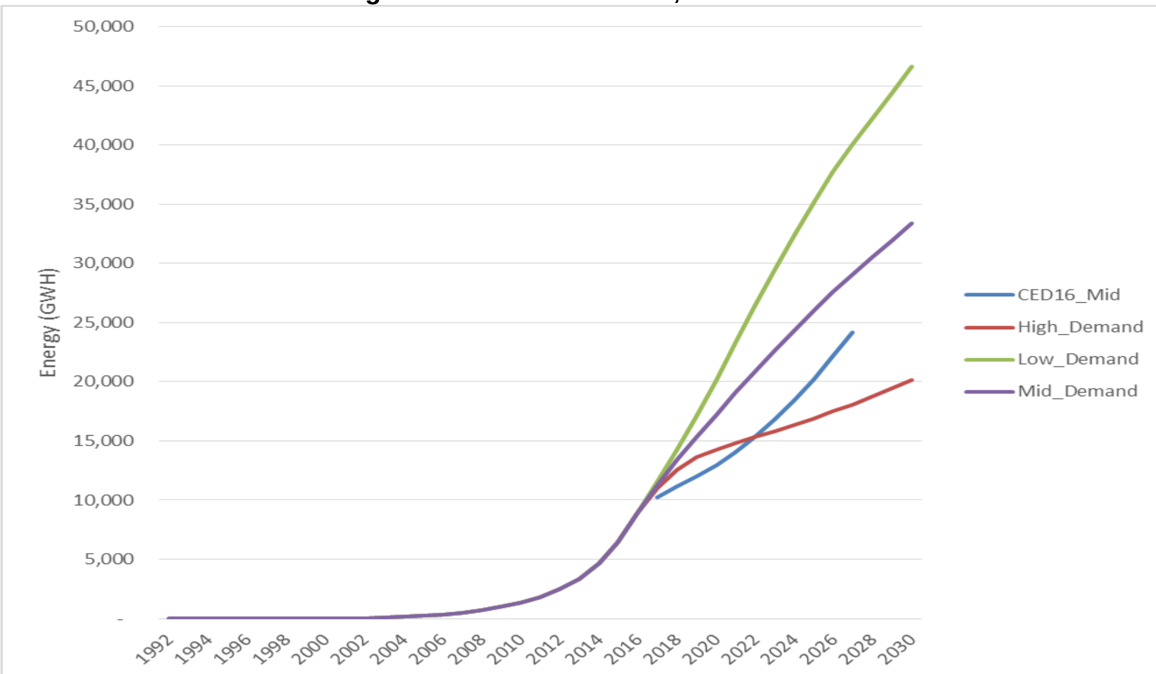
Figure A-9 shows the non-PV generation, which reaches over 17,000 GWh by 2030 in all three cases. The rapid increase after 2018 occurs because of the need to account for pending fuel cell projects currently moving through the SGIP program. CHP additions in the SGIP slowed because of changes in program design, which limited participation mainly in fuel cells; SGIP now provides incentives for conventional CHP technologies and this has led to many pending projects moving through the various application stages. However, recent modifications to SGIP could limit participation for fossil-fueled CHP technologies.[125] Higher commercial floor space projections in the high demand case increase adoption relative to the other cases, while higher rates in the low case have the same effect. The net result is that all three scenarios are very similar throughout the

124 Ibid.

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

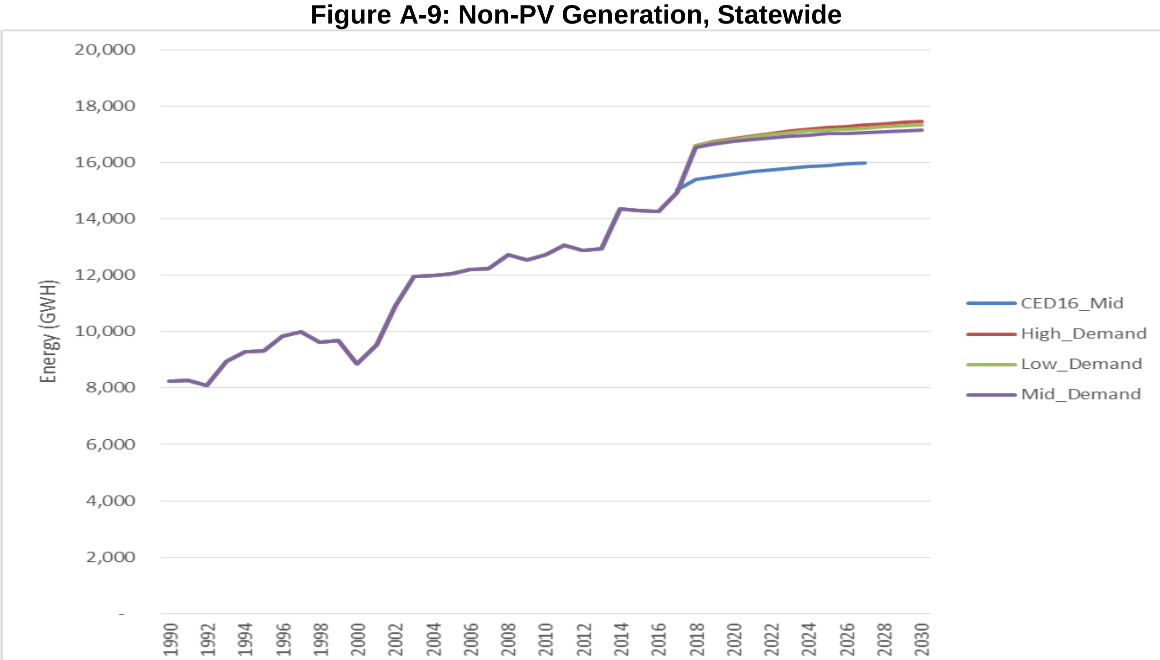
forecast period, with the high demand case yielding slightly more impact than the mid and low cases.

Figure A-8: PV Generation, Statewide



Source: California Energy Commission, Energy Assessments Division, 2017.

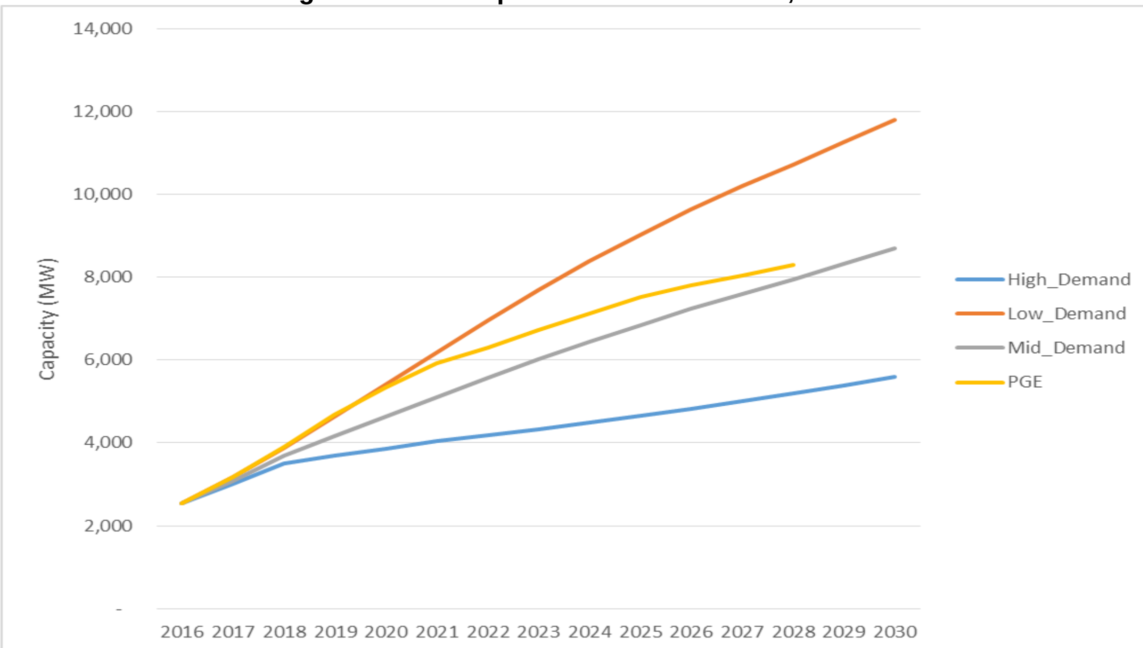
Figure A-9: Non-PV Generation, Statewide



Source: California Energy Commission, Energy Assessments Division, 2017.

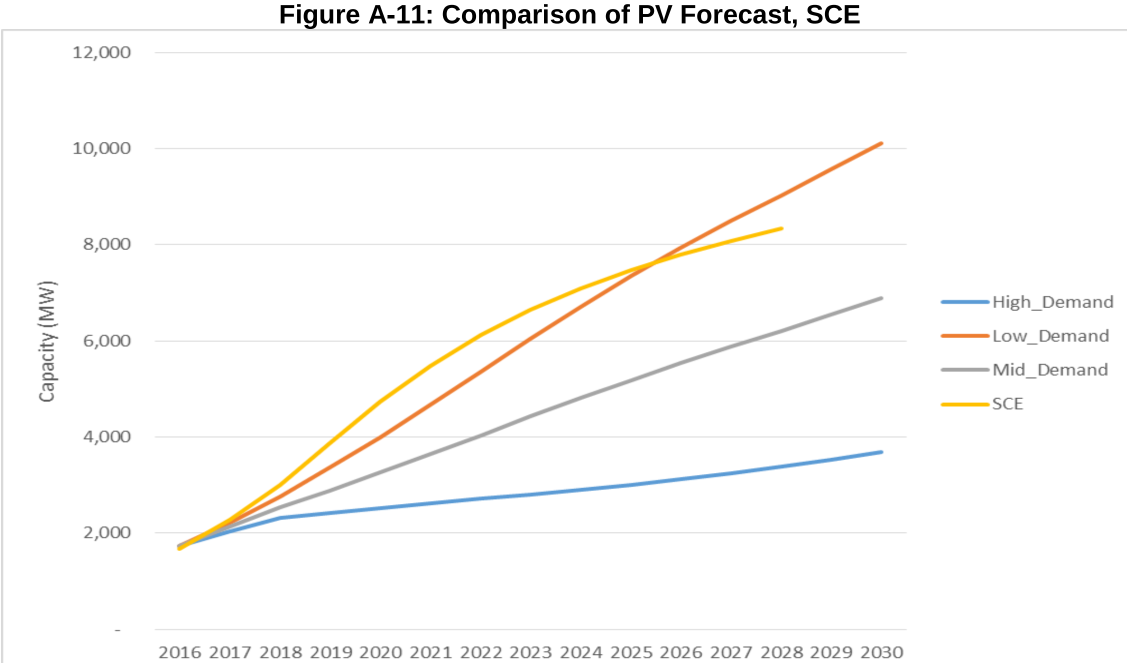
As part of the regular IEPR data collection, each utility submits a long-term demand forecast which includes impacts of distributed generation, energy efficiency, and demand response programs. **Figures A-10** through **A-12** compares staff's PV forecast to the PV forecast submitted by the investor-owned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

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



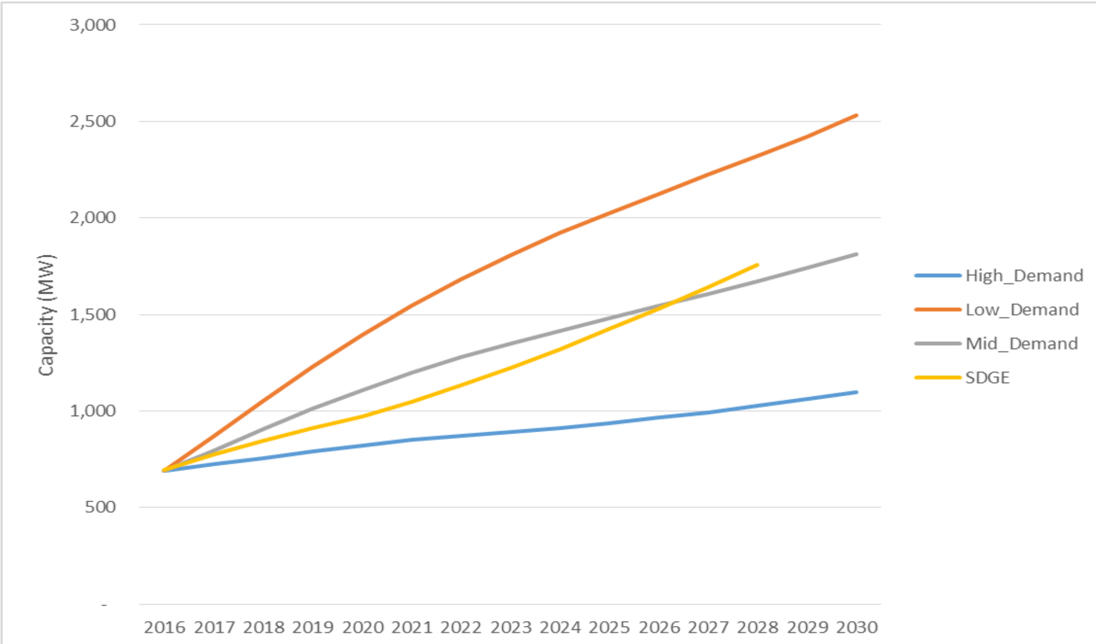
Source: California Energy Commission, Energy Assessments Division, 2017.

Figure A-11: Comparison of PV Forecast, SCE



Source: California Energy Commission, Energy Assessments Division, 2017.

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



Source: California Energy Commission, Energy Assessments Division, 2017.

Staff's forecast of PV adoption is lower than PGE's forecast over the forecast period for the mid (4 percent and 336 MW lower than PGE by 2028) and High Demand (37 percent and 3,000 MW lower than PGE by 2028) scenarios. Staff's forecast is higher than PGE's forecast for the Low Demand (30 percent and 2,400 MW higher than PGE by 2028) scenario.

Staff's forecast of PV adoption is lower than SCE's forecast over the forecast period for the mid (26 percent and 2,100 MW lower than SCE by 2028) and High Demand (60 percent and 5,000 MW lower than SCE by 2028) scenarios. Staff's forecast is higher than SCE's forecast for the Low Demand (8 percent and 700 MW higher than SCE by 2028) scenario.

Staff's forecast of PV adoption is lower than SDGE's forecast over the forecast period for the mid (5 percent and 84 MW lower than SDGE by 2028) and High Demand (42 percent and 700 MW lower than SDGE by 2028) scenarios. Staff's forecast is higher than SDGE's forecast for the Low Demand (32 percent and 500 MW higher than SDGE by 2028) scenario.

Additional Achievable PV Forecast

For *CED 2017 Revised,* staff developed scenarios to show the potential impacts of the Commission's 2019 Title 24 building standards. Specifically, the upcoming standards may require, where feasible, that new homes be built with a PV system. This scenario is based on the Zero Net Energy (ZNE) work underway at the Energy Commission and the

CPUC.[126] [127] For this scenario, staff limited their focus to single-family homes and used PV system sizes as recommended by staff in the Commission's Energy Efficiency division. The PV additions modeled in this scenario are incremental to the amount of PV already projected to be installed in new single-family homes from the baseline forecast. Based on stakeholder comments and internal discussions with staff from the Commission's Energy Efficiency division, for modeling this ZNE scenario, staff assumed that 70 percent of single family homes built after 2019 will have a PV system in the High Demand scenario and 90 percent in the Low Demand scenario while the mean of the additions between the two bookend scenarios making up the Mid Demand scenario.[128] [129] **Table A-2** compares PV capacity in the baseline forecast against the uncommitted PV scenario in 2030.

Table A-2: PV Capacity in 2030 (MW)

Demand Scenario	Baseline	Uncommitted	Difference
High_Demand	11,591	14,344	2,753
Mid_Demand	19,078	21,300	2,222
Low_Demand	26,564	28,256	1,692

Source: California Energy Commission, Energy Assessments Division, 2017.

Existing CHP Retirement Scenario

A scenario staff considered for *CED 2017 Revised* concerns the retirement of existing large-scale CHP plants, generally concentrated in industrial and mining sectors. As described earlier, staff updates historical generation data from existing CHP plants and assumes that these plants will continue operating over the forecast period at a constant annual output level–set at the generation level in the base year. Concerns surrounding ability of existing CHP plants to obtain new contracts could result in either early retirement or curtailment in output.[130] Staff worked collaboratively with the Commission's Supply Analysis Office (SAO) to develop alternative scenarios around existing CHP as shown in **Figure A-14**. In particular, staff assumed that in the Low Demand scenario, existing CHP plants would continue to operate at a constant annual output level similar to the assumption made in *CED 2017 Preliminary*. In the High Demand scenario, staff assumed that existing CHP plants would operate up to their existing contract end data and then shut down. For the Mid Demand scenario, staff

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

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

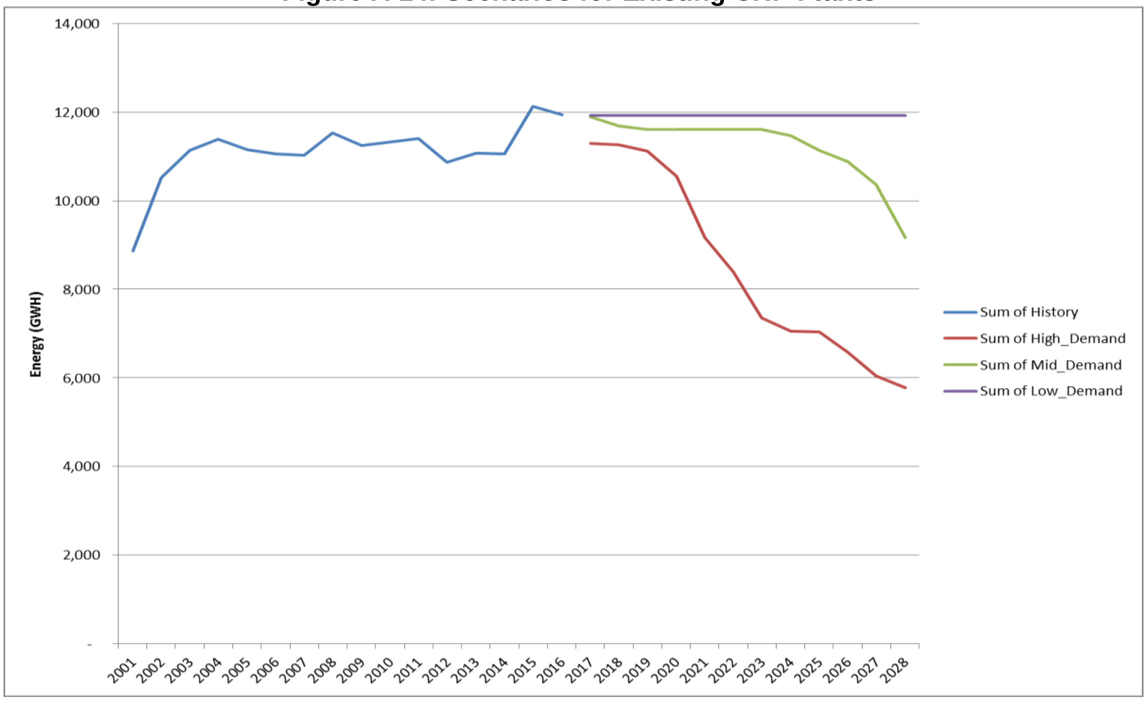
128 Demand Analysis Working Group meeting on 2017 IEPR Preliminary forecast held on July 14, 2017. (http://www.dawg.info/meetings/dawgs-demand-forecasting-subgroup).

129 IEPR workshop on the 2017 IEPR Preliminary forecast on August 3, 2017 (http://www.energy.ca.gov/2017_energypolicy/documents/#08032017).

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

assumed that CHP plants would operate up to their existing contract end date and then reduce total generation back to meet only the host's onsite demand up to the nameplate capacity of their newest generating unit until this unit is 40 years old, at which point the plant shuts down.

Figure A-14: Scenarios for Existing CHP Plants



Source: California Energy Commission, Energy Assessments Division, 2017.

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

APPENDIX B: Potential Energy Demand from Legalized Cannabis

Introduction

On November 8, 2016, Californians approved Proposition 64, the *California Marijuana Legalization Initiative* that made it legal for individuals to grow and consume marijuana for recreational purposes on and after November 9, 2016. Proposition 215 in 1996 had already legalized the medical use of marijuana in California. Proposition 64 made it legal for persons of age 21 and older to grow and consume marijuana for recreational purposes in a private home or a licensed business establishment. Individuals could also share limited amounts of marijuana with each other. The sale of recreational marijuana became legal on January 1, 2018, although consumption of marijuana in public places remains illegal. California is the fifth state to legalize the recreational use of marijuana after Colorado, Washington, Oregon, and Alaska.[131] Legalization creates concerns from an energy point of view because cultivation can be quite energy intensive. This appendix discusses the potential ramifications for the electricity grid of cannabis legalization. Note that references referred to in the footnotes are provided at the end of this appendix.

Legalization of cannabis production raises several issues for energy forecasting, system reliability, rate design, and energy efficiency policies. Obviously, the most important question is the effect of marijuana production on electricity demand and load. Indoor production of marijuana is known to be quite energy intensive. The first challenge in assessing the effect of cannabis production on energy, load, and system reliability is that reliable and comprehensive data on the subject does not exist. This is mainly because of the illegal nature of the production and consumption of the commodity. A 2012 study by Evan Mills estimated that electricity consumption attributable to cannabis in the United States was 1 percent of total energy consumption, with a value of $6 billion. The same study indicated that indoor cannabis production was responsible for 3 percent of California's total energy usage, or 9 percent of residential usage.[132] Obviously, these statistics are old and pertain to the pre-legalization era. They nevertheless suggest the potential size of the problem. Collecting reliable and comprehensive data on cannabis production and energy usage should be a priority for both utilities and regulators.

131 See Steinmetz (2016) and Ballotperdia (2016).

132 Mills (2012).

Legalization of marijuana could lead to several trends in production and consumption, sometimes with opposite impacts on energy demand and load. This results in a great deal of uncertainty about the effects of these activities on energy demand and CO_2 emissions. Legalization could encourage more indoor production with the resulting increase in energy demand and the reduction in system reliability.[133] On the other hand, the illicit nature of the commodity and the need for secrecy had resulted in suboptimal production techniques with adverse impacts on the environment. For example, some growers use in-house generators to escape detection by utilities and authorities. The amount of CO_2 emitted by these generators is about three times the amount that would be produced through the grid. Therefore, legalization could increase energy consumption, but reduce CO_2 emissions.[134] Moreover, legalization could reduce energy theft by grow houses and increase utility revenues, which could be spent on system reliability or energy efficiency upgrades.[135]

A related issue for California is that consumption of marijuana at a national level will affect energy demand in California through the export of this commodity to other states. As noted below, according to some anecdotal evidence, California's exports to other states are about four times the state consumption. If legalization trends continue, California exports could increase or decrease in the future, depending on other states' production relative to consumption. If legalization of marijuana in other states results in consumption increasing more than production, California's exports to those states could increase, causing increases in in-state production. In the opposite case, exports could decrease resulting in a reduction in production. The Energy Commission's forecasting models and methods should, therefore, take out-of-state developments and the corresponding uncertainties into consideration.

What makes this issue particularly important for both utilities and regulators is that cannabis production is a highly energy intensive process. Commercial producers of marijuana generally prefer indoor production facilities, partly because they have better control on lighting and temperature. Moreover, while outdoor production has generally one to two growth cycles per year, indoor production can achieve five or more cycles per year.[136] Additionally, land-use restrictions by local and city governments further encourage indoor production of the crop.[137]

133 As reported by Crandel (2016), both Oregon and Portland have experienced system outages and equipment breakdowns attributable to grow houses.

134 Mills (2012) and Ashworth and Vizuete (2016).

135 BC Hydro (British Columbia) reported to have identified $100 millions of lost revenue due to electricity theft the majir portion of which came from marijuana producers. See Crandel (2016, page 8).

136 See Crandall (September 2016). In a recent survey conducted by CalCannabis, 45 percent of California growers indicated their preference for indoor production. See Mulqueen, et. al. (2017 page 17). The CalCannabis survey can be found in https://www.cdfa.ca.gov/is/mccp/news/36.

137 See Mulqueen, et. al. (2017 page 18-19).

Traditional indoor production facilities use highly energy-intensive sodium floodlights to grow the cannabis plants. These lights also create heat. Therefore, grow facilities use air-conditioning to reduce the temperature. Cannabis plants also create water vapor. As a result, ventilators and dehumidifiers are used to control moisture. Grow houses generally use energy intensive dehumidification systems to maintain indoor conditions required for cannabis farming.[138] Lighting, air-conditioning, dehumidification, and venting account for about 90 percent of energy consumption in grow facilities. Drying and curing the final product require additional energy usage.[139]

Besides the effects on energy demand and system reliability, legalization of cannabis production raises serious questions about its effect on the environment, both in terms of CO_2 emissions and water contamination. In addition to the sub-optimal production techniques mentioned above, the illicit nature of the commodity has resulted in a paucity of relevant data on CO_2 emissions. Better and reliable data is needed to evaluate the effect of marijuana production on the environment. According to Mills (2012), lighting, ventilation, dehumidification, and air-conditioning account for about 80 percent of CO_2 emissions from an indoor grow facility. Given possible information problems and a lack of incentives on the part of the producers concerning energy-efficient production methods, legalization could provide opportunities for both utilities and regulators to design polices to reduce energy consumption as well as carbon emissions.

Energy efficiency audits and information campaigns by utilities could be effective in educating grow house operators about more efficient production techniques and emerging new technologies. For example, incentive payments and rebate programs for grow houses to switch to LED lights could have measurable impact on energy usage. Moreover, efficient rate design such as time of use rates could incentivize producers to adopt energy efficient growing techniques.[140]

Cannabis Energy Usage Issues

At the most basic level, total energy used to produce marijuana can be represented by the following simple formula:

$$E = e \times Q,$$

Where *e* is the energy used per unit of marijuana produced, or energy intensity, and Q is the quantity of marijuana produced per unit of time, such as a year. As simple as the above formula looks, its implementation is beset with several challenges.

To begin with, historical data on the production and consumption of marijuana is scarce because of the illegal nature of these activities in the past. This by itself makes the

138 See Western Cooling Efficiency Center (WCEC), undated.

139 See Crandall (September 2016), Kat Kerlin (December 2016), and Evergreen Economics (2016, page 9).

140 See Evergreen Economics (2016) and Crandel (2016).

implementation of the above formula a daunting task. Most existing estimates of production and energy use are based on a combination of surveys collected by state governments and private business firms, as well as anecdotal evidence.

Scant information exists on the amount of marijuana consumed per user. The major reason for the lack of reliable data on the quantity of marijuana consumed is that respondents to survey questions generally do not have a sense of the weight of the cigarettes they are consuming. Further complicating the matter is the fact that marijuana is consumed through different media, such as candy bars and brownies, and that different groups consume it with different frequencies and intensities. Moreover, since cigarettes are frequently shared among users, estimates of grams consumed per user would be somewhat unreliable.[141]

As further examples of challenges facing the analyst, energy used per unit (*e*) depends on the method of growing the cannabis plant (outdoors, greenhouses, or indoors). Moreover, as mentioned, marijuana can be consumed through non-smoking means. Therefore, estimation of energy use should probably also include or make assumptions about the amount of energy used to produce the complementary ingredients in the candy bars and brownies (such as sugar), as well as the energy used by the equipment that produces these intermediary products. To be comprehensive, energy used in distribution of the product should also be taken into consideration. Finally, the quantity of marijuana (Q) produced must be estimated as published data on this variable is rather scarce.

Cannabis Demand

The Substance Abuse and Mental Health Services Administration (SAMHSA) of the U.S. Department of Health and Human Services collects samples of substance abuse at the national and state levels called the National Survey on Drug Use and Health (NSDUH). These samples are collected over a period of two years and the averages for those two years are reported annually. The surveys ask respondents whether they had used an illegal substance in the past year or the past month. For example, the average over two years 2014 and 2015 of the number of respondents who had said they had used marijuana in the past year was over 35 million.

Table B-1 presents the sample results on marijuana use for the United States and California for recent years for those 12 years and older. These are the only years for which such sample data are available. The **Table B-1**shows that the number of people using marijuana in California has been increasing over time and, in 2014-2015, close to five million Californians used marijuana. The table also shows that California users constituted about 14 percent of national users during this period.

141 Kilmer, et. al. (2013).

Table B-1: Number of Marijuana Users in the Past Year 12 Years and Older, Annual Averages

	United States (Thousand Persons)	California (Thousand Persons)	Ratio of California to U.S.
Based on 2009 and 2010 NSDUH	28,996	4,148	14.3%
Based on 2010 and 2011 NSDUH	29,523	4,304	14.6%
Based on 2011 and 2012 NSDUH	30,627	4,379	14.3%
Based on 2012 and 2013 NSDUH	32,231	4,384	13.6%
Based on 2013 and 2014 NSDUH	34,038	4,633	13.6%
Based on 2014 and 2015 NSDUH	35,584	4,936	13.9%
Over the two-year period indicated in column 1, respondents are asked if they had used marijuana in the past year. Annual averages are the averages of users in those two consecutive years.			

Source: Substance Abuse and Mental Health Services Administration, 2016.

Table B-2 presents the results of the samples asking respondents whether they had used marijuana in the past month. These numbers are broadly consistent with those in **Table B-1**. The table shows that the number of past-month users has been increasing over the last several years and that California users constitute about 14 percent of the national total. Since people generally have a better memory of the past month than the past year, researchers generally use the past-month data for their analyses, and staff will follow suit.

Figure B-1 shows the prevalence of marijuana usage since 2002 estimated by SAMHSA. These are the percentages of population 12 years old and older that have used marijuana since 2002. Two patterns stand out. First, the percentage was more or less constant from 2002 through 2007. Second, it began to increase in 2008. The latter pattern coincides with the era of Great Recession. Further research is needed to analyze whether the recession was the cause of the increase in usage. Note that the percentages for past-month responders are lower; respondents tend to be more certain of use over a year compared to a much shorter period of time.

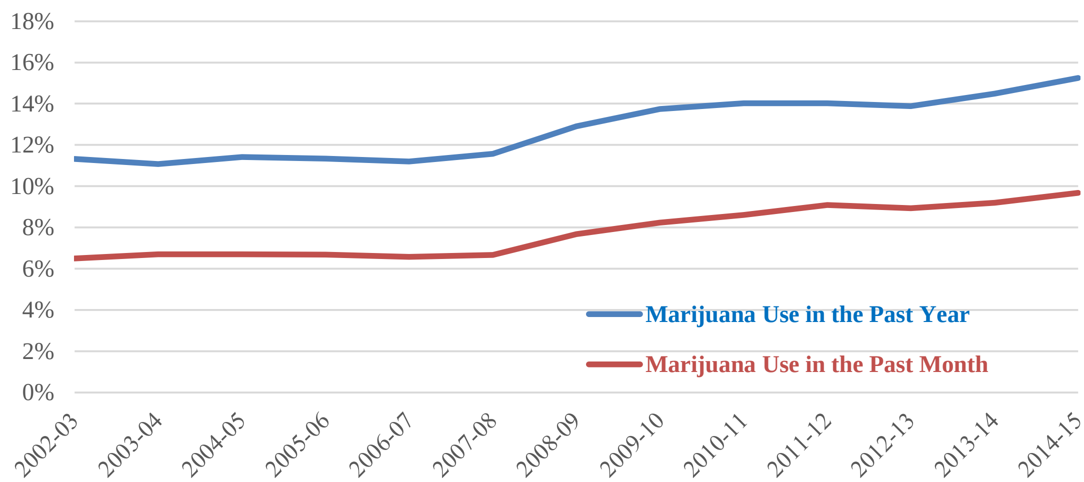
Table B-2: Number of Marijuana Users in the Past Month 12 Years and Older, Annual Averages

	United States (Thousand Persons)	California (Thousand Persons)	Ratio of California to U.S.
Based on 2009 and 2010 NSDUH	17,119	2,487	14.5%
Based on 2010 and 2011 NSDUH	17,741	2,642	14.9%
Based on 2011 and 2012 NSDUH	18,463	2,836	15.4%
Based on 2012 and 2013 NSDUH	19,332	2,822	14.6%
Based on 2013 and 2014 NSDUH	20,999	2,942	14.0%
Based on 2014 and 2015 NSDUH	22,207	3,133	14.1%

Over the two-year period indicated in column 1, respondents are asked if they had used marijuana in the past month. Annual averages are the averages of users in those two consecutive years.

Source: Substance Abuse and Mental Health Services Administration, 2016.

Figure B-1: Prevalence of Marijuana Usage in California, Age 12 Years and Older



Source: Substance Abuse and Mental Health Services Administration, 2016.

Estimating the Historical Quantity of Usage and Electricity in California

According to Light, Orens, et. al. (2014), who studied the marijuana market for Colorado, due to different frequency and intensity of marijuana use by different consumer groups, estimating and forecasting the total usage by simply multiplying the average usage by the number of users would lead to biased and imprecise estimates. If the distribution of marijuana usage over different groups was flat or symmetric, multiplying the average usage per day by the total number of days would give an accurate answer. Otherwise, the result would be biased. As explained below, in the case of marijuana, we would be underestimating the usage. To see this, suppose that 100 users consume 1 gram of marijuana each day for 10 days a month. Another 100 users consume 2 grams for 20 days a month. In that case, the total monthly marijuana consumption by these two groups equals 5,000 grams:

$$100 \times 10 \times 1 + 100 \times 20 \times 2 = 5{,}000 \text{ grams}$$

If we applied the average usage of 1.5 grams per day to 30 days of the month we would underestimate the usage:

$$100 \times 30 \times 1.50 = 4{,}500 \text{ grams}$$

Several studies have documented a positive correlation between use frequency and use intensity. In other words, as in our example above, those who use marijuana more frequently (larger number of days per year) also use it more intensively (larger quantities per each day) compared to other, less frequent users. For this reason, heavy users generally dominate the demand side. The amounts consumed by heavy users (those who use marijuana more than 20 days a month) are estimated to be 2 to 4 times those consumed by other less frequent users.

Table B-3, adopted from Kilmer et. al. (2013), shows the results of a 2001 survey by the National Epidemiologic Survey on Alcohol and Related Conditions (NESARC) on the number of marijuana cigarettes consumed by different groups of users. The table multiplies the survey data by the estimated average weight of a cigarette from Kilmer, Caulkins, Bond, and Reuter (2010, Appendix A). According to these authors, this average is 0.46 grams (with a 95-percent confidence interval of 0.43-0.50). The table clearly shows the positive correlation between frequency and intensity of use. The usage by heavy users (20+ days per month) is more than three times that of light users (less than 1 day a month). Caulkins and Kilmer (2013) report a similar pattern for Europe.

Table B-3: NESARC Mean Number of Cigarettes and Grams Per Day (2000/2001)

Type of User	Cigarettes	Grams
20+ days a month	3.87	1.7802
Less than 20 more than 3 days a month	1.92	0.8832
1 to 3 days a month	1.68	0.7728
less than I day a month (less than 12 days per year)	1.17	0.5382
Grams were calculated by multiplying 0.46 grams per cigarettes from Kilmer, Caulkins, Bond, and Reuter (2010) by the number of joints.		

Source: National Epidemiologic Survey on Alcohol and Related Conditions, 2001.

Staff used a methodology similar to the one employed by Kilmer et. al. (2013, page 13) and Light, Orens, et. al. (2014, page 10) to estimate the amount of marijuana used in California. It must be emphasized that these estimates are quite preliminary and are mostly for illustrative purposes. Staff will improve the estimates as new and better data become available on marijuana production and usage. The marijuana consumption in

California in a particular year using SAMHSA national data can be estimated using the following formula:

$$Q = \sum_{D=1}^{30} N_D \times R_{CA} \times D \times G_D \times 12$$

Where,

Q = Average marijuana usage in a particular year in California.

N_D = Number of consumers who consume marijuana D days per month in the U.S.

R_{CA} = Ratio of California users to national users from Table 4.

D = Number of days a consumer consumes marijuana per month.

G_D = Grams of marijuana consumed by the consumers who consume D days per month.

Staff used SAMHSA's Public-Use Data Analysis System (PDAS) to obtain estimates of the number of users and usage amounts for the United States for the years 2002 to 2015. This is an online data analysis system that provides the number of marijuana users and the number of days in a month each user consumed marijuana. PDAS does not provide state-level data and, thus, staff had to share down the national level numbers to California using the ratios in **Table B-2**. For instance, the 2014-2015 ratio was applied to 2015 national numbers from PDAS to obtain the California number for 2015. Similarly, the 2009-2010 ratio was used to estimate the 2010 numbers for California. For the years prior to 2009, the average of the ratios in Table 4 was used for pro-ration. Finally, as in Kilmer et. al. (2013) and Light, Orens, et. al. (2014), we adjusted the estimates for an assumed 22 percent underreporting by respondents by dividing the unadjusted numbers by 1 –22% = 78%. Underreporting occurs partly due to the perceived illegal nature of marijuana and partly due to the stigma attached to its usage.

For every year from 2002 to 2015, the PDAS database provides the average of the number of days respondents had used marijuana in the past 30 days. Therefore, if, for instance, the survey asks the question of a respondent in March 2015 about the number of days of usage in the past 30 days, and if the respondent's answer is 3 days, then all of the 3 days would fall in February 2015. However, if the question were asked in January 2015 and the answer were 4 days then some of these days might fall in December 2014. The point is that a small number of days reported in 2015 PDAS dataset pertain to both 2015 and 2014. This does not seem to be a significant problem and most other researchers have ignored it.

As to the quantity of marijuana consumed per day, a study by Kilmer et. al. (2013) estimates that heavy users (those who consume marijuana 21 days of the month or more) consume 1.6 grams per day. The literature seems to agree on this number.[142] Staff further follows the same study and the existing literature by assuming the light users (those using one day a month), use one third of that amount or 0.53 grams per day. The amount of usage between 2 days a month and 20 days a month is then interpolated linearly between those two anchor numbers.

We provide an example to demonstrate the working of the above formula. According to PDAS, 4,245,310 consumers used marijuana 30 days a month in 2013 in the United States. California's share in 2015 was 14.6 percent from Table 4, or 619,712 users for a total of 4,245,310 × 30 = 18,591,347 person-days. Each of these users consumed 1.60 grams per day for a period of 12 months. So, total marijuana consumed by these heavy users was:

$$N_D \times R_{CA} \times D \times G_D \times 12 = 4{,}245{,}310 \ \times 0.146 \times 30 \times 1.60 \times 12 = 356{,}953{,}853 \text{ grams}$$

Therefore, this group of Californians alone consumed an estimated 357 metric tons of marijuana in 2013.

Table B-4 shows the results for six user groups for 2015. As estimated, close to 22 million Americans and 3 million Californians used marijuana in 2015. The total amount used, adjusting for underreporting, was 1,018.6 metric tons of the product. It is noteworthy that, as expected, heavy users dominate the estimates. Close to 76 percent of the usage comes from heavy users (21 days of usage or more). In addition, those who consume marijuana 16 days or more account for 87 percent of usage.[143]

Table B-4: Estimated Marijuana Usage in California, 2015

Number of Days per Month	Grams Used Per Day	Number of Users in 2015 (U.S.) (thousands)	Number of Users in 2015 (CA) (thousands)	2015 Total Used in California (Metric Tons)	2015 Total for California Adjusted for 22% Under-reporting (Metric Tons)	Percent of Total
1	0.53	2,927	413.01	2.6	3.4	0.3%
2 - 5	0.67	5,512	777.70	20.5	26.2	2.6%
6 - 10	0.91	2,588	365.09	33.8	43.3	4.3%
11 - 15	1.18	1,559	219.90	45.0	57.7	5.7%
16 - 20	1.44	1,825	257.44	91.5	117.3	11.5%
21 - 31	1.60	7,815	1,102.54	601.1	770.7	75.7%
Totals		22,226	3,136	794.5	1,018.6	100.0%

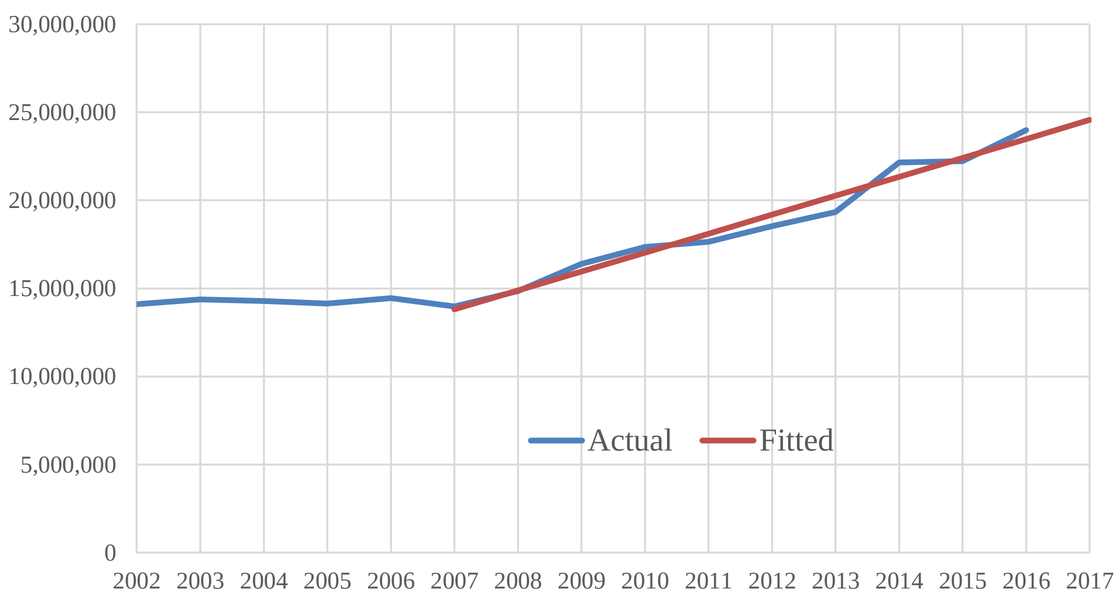
Source: California Energy Commission, Energy Assessments Division, 2017.

142 Light, Oren et. al. (2014) also use this number in their study of Colorado market.

143 Staff had to adjust the original 2015 estimates. The original usage estimates based on SAMSHA data were deemed too low, perhaps due to sampling error. However, SAMSHA had later updated estimates of total users in the U.S. for 2015 and 2016. Staff used the 2015 estimate of total users and the 2015 distribution of the number of users over the number of days to generate the estimates for California.

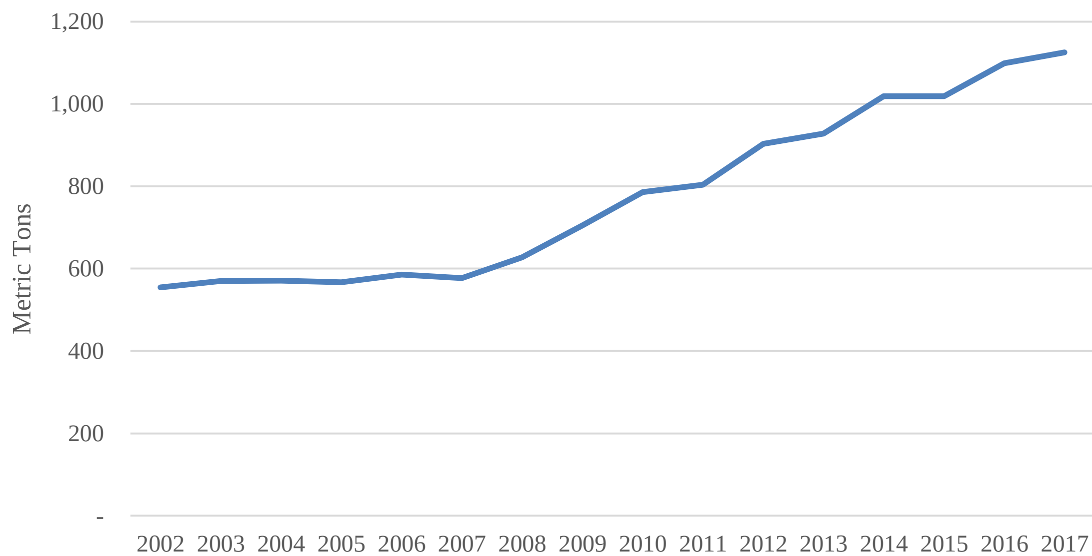
Staff repeated this exercise for all years 2002 — 2014 assuming the same grams per day by type of user and the same adjustment for under-reporting. To complete an historical time series, usage for the two pre-legalization years 2016 and 2017 was estimated. Recently, SAMHSA has estimated the total number of users for 2015 and 2016 for the United States. Staff employed the 2016 estimate and the 2015 distribution of the percentage of users over the number of days to estimate the distribution of the *number* of users over the number of days. Staff shared down these numbers to California using the average of the ratios of California to U.S. users for 2002 through 2015 from SAMHSA. At this point, staff used the same assumptions about the number of grams to estimate the total amount consumed in California. For 2017, staff used a simple time trend of the total number of users in the United States from 2007 to 2016 to project the number of users in 2017, as shown in **Figure B-2**. Staff chose the year 2007 as the starting point due to the observed break in the time-series pattern in this year (see **Figure B-1**). The projected number of users in 2017 turned out to be 24,557,000 persons in 2017. Staff then used this number and the same methodology used to forecast the 2016 usage to estimate 2017 usage in California. **Figure B-3** shows the resulting estimates for metric tons for each year 2002 — 2017.

Figure B-2: Fitted Time Trend for Total Number of Marijuana Users in the United States



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure B-3: Estimated Historical Usage of Marijuana in California



Source: California Energy Commission, Energy Assessments Division, 2017.

At least two more basic adjustments should be made to any demand side estimate of cannabis in order to obtain estimates of production quantities relevant to energy usage. First, some anecdotal evidence indicates that California's marijuana exports to other states are about four times the in-state consumption.[144] Adopting this assumption means that, using the estimate in **Table B-2**, 2015 total cannabis production in California was roughly five times cannabis consumption, or approximately 4,718 metric tons. The second adjustment necessary to make the production amount relevant for energy consumption is to eliminate outdoor production. The available data, provided by DrugScience.org for 2006 and presented in **Table B-5**, indicate that total indoor production in California accounted for 20 percent of plants and 11 percent of production quantities.[145] Staff believes that the best indicator is the number of cannabis *plants* grown indoors as opposed to production quantity, because it is the plants that use energy to grow. Based on this estimate, one can conclude that about 943 metric tons of cannabis was produced indoors in California in 2015 (0.20 × 4,718 metric tons). Data permitting, this number would further need to be decomposed into greenhouse and "true" indoor production amounts because of the different impacts of these two production methods on energy consumption. At this point, though, staff has not been able to find the relevant data on this breakdown. The two adjustments, then, roughly cancel each other out, so staff used the totals in **Figure B-3** to also represent indoor production.

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144 Mulqueen, Lee, and Zafar (2017). According to Gettman (2006), the ratio of California's production to usage in 2006 was 2.92. This indicates that exports were only twice the state consumption. These numbers, however, pertain to pre-legalization era.

145 Jon Gettman (2006). The same report indicated that at the federal level, outdoor production accounted for 83 percent of plants. The report did not provide a breakdown of production quantities into indoor and outdoor components.

As in other aspects of cannabis production, data on energy usage is very limited. As mentioned above, of the three production activities taking place outdoors, in a greenhouse, and indoors, the indoor production method is the most energy intensive. Moreover, there seems to be an upward trend in this production method because producers have greater control on such production conditions as temperature, lighting, and humidity. This production method could reduce the production life cycle and result in more predictable quantities and better product qualities. In general, cannabis production energy costs accounts for 20 to 50 percent of the total production cost of a grow facility.[146]

Table B-5: 2006 Plants and Production of Marijuana in California and the U.S.

	Plants		Production		
	Number of Plants	Percent of Total	Production Quantity (lbs.)	Percent of Total	Value ($1000s)
Outdoor (California)	17,445,553	80%	7,692,043	89%	$12,353,421
Indoor (California)	4,222,055	20%	930,788	11%	$1,494,846
Total California	21,667,608	100%	8,622,831	100%	$13,848,267
United States	68,100,000		22,300,000		$35,800,000

Source: Drugscience.org, 2017.

Table B-6 shows the energy intensities for indoor and greenhouse cannabis production by end use as estimated by Mills (2012). It shows that lighting, venting, and air conditioning account for about 90 percent of total energy usage. These data could indicate the reason why several electric utility companies have experienced power outages after the increase in cannabis production in their states.147 Mills estimated these intensities assuming "standard" production conditions. The table also shows the overall electricity intensity of cannabis production. There is of course a great deal of uncertainty about these estimates, as Mills notes.

Applying the estimated total energy intensity in **Table B-6** to the estimated indoor cannabis production quantities gives electricity usage in California, as shown in **Table B-7.** The table also shows cannabis electricity consumption as a percentage of residential and total electricity consumption, both of which have been on the rise in California.

146 See Evergreen Economics (July 15, 2016), and the references therein.

147 See Evergreen Economics (July 15, 2016), and the references therein.

Table B-6: Energy Intensity of Marijuana Production by End Use

End-Use	Energy Intensity (kWh/kg Yield)	Percent of Total Usage	Cumulative Sum
Lighting	2,283	38%	38%
Venting and Dehumidifying	1,848	30%	68%
Air Conditioning	1,284	21%	89%
Space Heating	304	5%	94%
Water Consumption	173	3%	97%
CO2 Injection	93	2%	99%
Drying	90	1%	100%
Total	6,075	100%	

Source: Mills (2012).

Table B-7: Estimates of Total Cannabis Energy Consumption in California

Year	Estimated Indoor Production Including Exports (Metric Tons)	Electricity Used for Indoor Cannabis Production (GWh)	Residential Electricity Demand (GWh)	Ratio of Cannabis to Residential Electricity Demand	Total Electricity Demand (GWh)	Ratio of Cannabis to Total Electricity Demand
2002	554.89	3,371	76,765	4.4%	256,348	1.3%
2003	570.31	3,465	81,715	4.2%	261,937	1.3%
2004	570.68	3,467	83,838	4.1%	271,026	1.3%
2005	566.98	3,444	85,677	4.0%	272,726	1.3%
2006	585.53	3,557	89,728	4.0%	281,662	1.3%
2007	576.94	3,505	89,100	3.9%	285,366	1.2%
2008	627.65	3,813	90,946	4.2%	285,447	1.3%
2009	705.40	4,285	90,084	4.8%	277,258	1.5%
2010	786.02	4,775	87,448	5.5%	272,703	1.8%
2011	804.17	4,885	88,748	5.5%	275,646	1.8%
2012	903.49	5,489	91,124	6.0%	281,313	2.0%
2013	927.70	5,636	90,030	6.3%	279,172	2.0%
2014	1,018.93	6,190	90,078	6.9%	281,891	2.2%
2015	1,018.60	6,188	90,677	6.8%	282,380	2.2%
2016	1,045.83	6,353	90,886	7.0%	284,060	2.2%
2017	1,070.97	6,506	92,072*	7.1%	285,011*	2.3%

*Forecast

Source: California Energy Commission, Energy Assessments Division, 2017

It must be stressed that the paucity of data and the anecdotal nature of most of what is available generate a great deal of uncertainty about these estimates. The major uncertainties relate to the sampling errors in the SAMHSA's estimates of the number of users, grams used per day, and the extent of underreporting, as well as energy intensity.

Forecasting Cannabis Energy Use

At this point, predicting cannabis energy consumption in California is obviously quite speculative. Industry experts and commentators have conflicting opinions about the direction of the movement in energy usage.[148] There are factors that point to an increase in energy usage:

- Legalization will increase demand and production.
- Stand-alone inefficient generators will disappear and indoor grow houses will draw power from the grid. This will simultaneously increase energy and load and reduce carbon emissions.
- The lucrative nature of the product will incentivize some farmers and wineries to switch to cannabis production. Many warehouses will also be converted into indoor grow houses.
- Due to high yield and better quality of the product produced indoors, not many indoor facilities will convert to greenhouses or outdoors.

There are also those who argue that energy consumption may not increase and may even decrease:

- Legalization will incentivize growers to adopt more energy efficient equipment. For example, they could install better air conditioners or dehumidifiers. They could also install energy-efficient LED lights. This last point is somewhat controversial, as some believe that LED lights are inferior to the lights used currently in terms of the quality of the product.
- Indoor grow houses could use renewable sources of energy such as solar power.
- State subsidies and proper rate design could provide incentives for the growers to invest in energy efficient methods.
- California's weather is conducive to outdoor production. Therefore, some indoor facilities will move to greenhouses and outdoors. This point is also controversial, as others believe that the main reason for producing marijuana indoors is greater yield and better quality and this will not change with legalization.

148 See Martin (2017), Mulqueen et. al. (2017), and Sangree (2017) for a brief discussion.

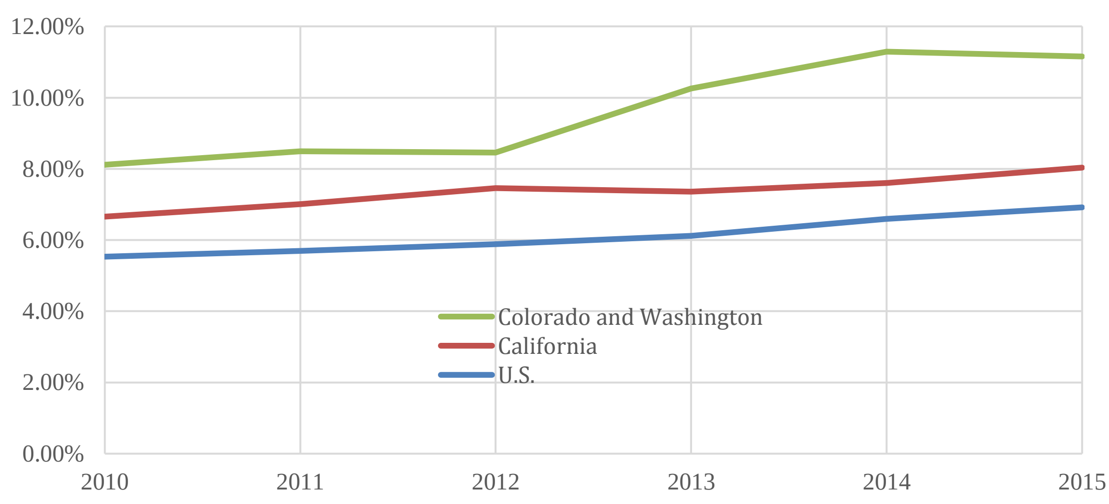
- Possible legalization in other states and even by the federal government in the future could reduce California's exports and production.
- The federal government could strictly enforce federal laws prohibiting the distribution and sale of cannabis.

The actual experience with legalization also seems to be mixed. According to Xcel Energy, a provider of power in Colorado, legalization resulted in 1 to 2 percent increase in power usage.[149] Similar gains have been observed in Washington State. However, according to Martin (2017), some of the gains have not lasted.

Post-Legalization Forecast for California

For an illustrative post legalization forecast for California, staff considered the experiences of Colorado and Washington State, each of which legalized marijuana in 2012. **Figure B-4** shows the ratios of marijuana users to population in the United States, California, and combined Colorado and Washington State (the sum of the users in the two states divided by the sum of the populations of the two states). We consider the ratios in order to eliminate the possible effect of population growth on cannabis consumption. The post-legalization jump in this ratio for the two states is unmistakable. This ratio increased at a decreasing rate for two years after 2012 and became flat (even somewhat decreasing) in the third year. The same pattern is evident for the total number of users in the two states.

Figure B-4: Marijuana Users as a Percentage of Population



Source: Substance Abuse and Mental Health Services Administration, 2016.

Three points should be made in this connection. First, the increase in the ratios and number of users in Colorado and Washington State may well be the artifact of

149 In Mulqueen (2017 page 6) this percentage is quoted as 0.6 percent.

legalization rather than a true increase. In other words, the number of users could have been the same before and after legalization, but more people might have been willing to admit use after the legalization. This could be a reason why researchers and observers have not found drastic post-legalization increases in marijuana *usage* in these states even in the face of a large increase in the *number* of users. We will come back to this point again below.

Second, the increase in the number of users, although a useful benchmark, may not perfectly correlate with the amount of energy usage. This is because, as discussed below, changes in the production methods and/or improvements in energy efficiency might result in lower energy usage even in the face of an increase in the number of users. Third, one can see in **Figure B-4** a slight reduction in the ratio of users in California for 2012 — 2013. It is curious whether this is a mere coincidental correlation, or if there is a causal link between the two patterns. For example, legalization of marijuana in the two neighboring states might have led some Californians to buy the product in those states and this might have caused a change to their responses to the questionnaires.

Staff conducted a simple counterfactual experiment with the Colorado and Washington State data. As the pre-legalization number of users was nearly flat, we assumed the same pattern for the future absent legalization that the growth rate between 2011 and 2012 would continue into the future. Subtracting these totals from the actual number of users gives a rough estimate of the increase in the number of users because of legalization and yields percentages that we can apply to California with some modifications noted below. **Table B-8** shows the number of users estimated by SAMHSA and the counterfactuals after 2013. Staff will use this information in forecasting cannabis energy usage in California.

Table B-8: Colorado and Washington State Estimated Actual and Counterfactual Number of Users

Year	CO and WA Actual	Growth Rate	CO and WA Counterfactual	CO and WA Actual as a Percentage of Counterfactual
2010	957		957	0%
2011	1,014	6.0%	1,014	0%
2012	1,022	0.8%	1,022	0%
2013	1,255	22.8%	1,030	22%
2014	1,401	11.6%	1,038	35%
2015	1,407	0.4%	1,046	34%

Source: Substance Abuse and Mental Health Services Administration, 2016, and California Energy Commission, Energy Assessments Division, 2017.

Staff generated forecasts of cannabis energy usage for California from 2018 through 2030 as follows. For 2018 and 2019 we generated counterfactual business-as-usual forecasts of number of users assuming no legalization using the time trend noted in **Figure B-2**. Then, on the basis of the experiences of Colorado and Washington State observed in **Table B-8**, we assumed 22 percent increase in the number of users *relative to this counterfactual* number in 2018. However, we assumed that most of this increase—20 percent—come from non-heavy users and only 2 percent from heavy users. For 2019 we assumed a 35 percent increase in the number of users relative to the counterfactual, 32 percent from heavy users and 3 percent from non-heavy users.

Beginning in 2020, staff assumed that the number of users of both types will increase at the population growth rate of 1 percent. Although the data indicates that during 2008 to 2015, the number of users grew much faster than California population, such a high growth rate is not sustainable for the long run. We are also mindful of the distinct possibility that energy efficiency improvements and efficient rate designs will dampen energy usage somewhat in the future. Assuming 1 percent growth for the number of users is a compromise between the observed historical high growth rates and the possible effects of energy efficiency programs in the future.

Table B-9 presents the forecast of number of California users as well the amounts used by different groups. After legalization, the number of non-heavy users is assumed to increase faster than heavy users, so the percentage of usage by heavy users drops slightly after legalization. According to our assumptions and according to what has been observed for other states, the increase in the number of users in the first two years after legalization is more dramatic than the amounts used.

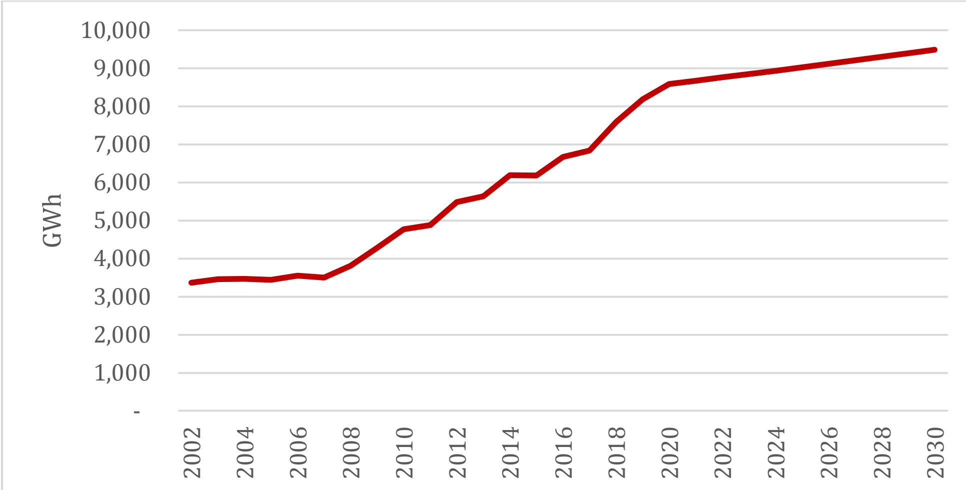
Figure B-5 shows the resulting projections for marijuana electricity use in California, which reach around 9,500 GWh in 2030, around 7.9 percent and 2.8 percent of residential and total baseline consumption, respectively, in the *CED 2017 Revised* mid case. These percentage are up from those estimated for 2017 (7.1 percent and 2.3 percent), although not drastically given staff assumptions.

Table B-9: Forecasts of Number of California Marijuana Users and Amounts Used

Year	Number of Users in California (Thousands)	Total Usage Adjusted for 22% Under-reporting (Metric Tons)	Usage by Heavy Users (21+ Days of Usage) (Metric Tons)	Percent Used by Heavy Users (21+ Days of Usage)	Usage by Frequent Users (16-20 Days of Usage) (Metric Tons)	Percent Used by Frequent Users (16-20 Days of Usage)	Usage by Light Users (1-15 Days of Usage) (Metric Tons)	Percent Used by Light Users (1-15 Days of Usage)
2002	2,055	554.6	372.1	67.1%	79.5	14.3%	103.0	18.6%
2003	2,096	570.0	384.1	67.4%	82.8	14.5%	103.0	18.1%
2004	2,083	570.4	393.8	69.0%	81.0	14.2%	95.5	16.7%
2005	2,062	566.7	397.0	70.1%	72.5	12.8%	97.2	17.1%
2006	2,107	585.2	394.2	67.4%	89.9	15.4%	101.1	17.3%
2007	2,038	576.7	425.1	73.7%	62.4	10.8%	89.2	15.5%
2008	2,165	627.3	442.0	70.5%	85.2	13.6%	100.2	16.0%
2009	2,390	705.1	505.3	71.7%	97.2	13.8%	102.6	14.5%
2010	2,520	785.7	580.0	73.8%	96.6	12.3%	109.1	13.9%
2011	2,629	803.8	594.0	73.9%	96.7	12.0%	113.1	14.1%
2012	2,846	903.1	667.3	73.9%	111.3	12.3%	124.5	13.8%
2013	2,823	927.3	707.5	76.3%	106.2	11.5%	113.7	12.3%
2014	3,104	1018.5	766.2	75.2%	116.8	11.5%	135.5	13.3%
2015	3,136	1018.2	770.7	75.7%	117.1	11.5%	130.4	12.8%
2016	3,383	1098.6	831.6	75.7%	126.3	11.5%	140.7	12.8%
2017	3,465	1125.0	851.5	75.7%	129.4	11.5%	144.1	12.8%
2018	4,111	1249.1	906.6	72.6%	162.1	13.0%	180.5	14.4%
2019	4,590	1346.4	953.9	70.8%	185.7	13.8%	206.8	15.4%
2020	4,813	1413.4	1001.9	70.9%	194.7	13.8%	216.8	15.3%
2021	4,862	1427.5	1011.9	70.9%	196.6	13.8%	218.9	15.3%
2022	4,910	1441.8	1022.1	70.9%	198.6	13.8%	221.1	15.3%
2023	4,959	1456.2	1032.3	70.9%	200.6	13.8%	223.3	15.3%
2024	5,009	1470.8	1042.6	70.9%	202.6	13.8%	225.6	15.3%
2025	5,059	1485.5	1053.0	70.9%	204.6	13.8%	227.8	15.3%
2026	5,110	1500.3	1063.6	70.9%	206.7	13.8%	230.1	15.3%
2027	5,161	1515.3	1074.2	70.9%	208.7	13.8%	232.4	15.3%
2028	5,212	1530.5	1084.9	70.9%	210.8	13.8%	234.7	15.3%
2029	5,264	1545.8	1095.8	70.9%	212.9	13.8%	237.1	15.3%
2030	5,317	1561.2	1106.7	70.9%	215.1	13.8%	239.5	15.3%

Source: California Energy Commission, Energy Assessments Division, 2017.

Figure B-5: Historical and Projected Electricity Use for Marijuana in California



Source: California Energy Commission, Energy Assessments Division, 2017.

Staff also developed alternative scenarios for electricity usage. SAMHSA reports the standard errors corresponding to their estimates of the number of users in the United States. For a low scenario, staff used two standard errors less than the SAMHSA mean estimates for the number of users in the U.S. and added two standard errors to the SAMHSA mean estimates to obtain the estimates under a high scenario. Kilmer, et. al. (2013) report that across many compositions of assumptions about the type and number of users in their study, the value of grams per day fell in the range from 1.30 to 1.90 with the modal value of 1.6. This modal number is what staff used in the estimates above. Moreover, assuming a normal distribution, with 90 percent probability the underreporting percent fell in the range 2 percent to 43 percent, with a mean of 22 percent as used above.[150] Staff used the lowest and highest numbers to generate low-high scenarios for energy consumption. The low scenario used 1.30 grams per day and an underreporting percent of 2 percent. The high scenario used 1.90 grams per day and an underreporting percent of 43 percent. Each layer of uncertainty was added into the estimates separately to get a sense of the importance of each for the forecasts. **Table B-10** shows the results of this exercise. As an example, accounting for uncertainty around the number of users means an error band of 8,156 GWh to 10,813 GWh in 2030; accounting for all three critical variables means an error band of 5,275 GWh to 17,571 GWh.

Concluding Observations

Staff provides this analysis as a way to begin to understand the issues involved in measuring and forecasting cannabis energy use along with some very preliminary magnitudes rather than as a forecast for policymakers. Cannabis production methods at existing indoor grow facilities are highly energy intensive. Besides this simple and well-known fact, there is a great deal of uncertainty about almost every aspect of marijuana

150 The Colorado study also used this 22 percent as noted previously.

production and consumption. There is not even a firm consensus among researchers and industry experts about the extent of increase in cannabis demand after legalization or whether energy use will increase or decrease. Given the potential importance of cannabis production for energy demand and system reliability as well its impact on carbon emissions, a careful study is warranted once better data on production methods and consumer demand become available.

Table B-10: Various Scenarios for California Cannabis Electricity Usage (GWh)

Year	Low Scenario: Under-reporting = 2%	Low Scenario: Grams Used = 1.30	Low Scenario: Number of Users Minus 2 Standard Errors	Mean Scenario: Grams Used = 1.6 & Under-reporting = 22%	High Scenario: Number of Users Plus 2 Standard Errors	High Scenario: Grams Used = 1.90	High Scenario: Under-reporting = 43%
2002	1.695	2.130	2.622	3.369	4.117	4.888	6.690
2003	1,753	2,202	2,711	3,463	4,215	5,005	6,849
2004	1,685	2,117	2,606	3,465	4,324	5,135	7,027
2005	1,654	2,078	2,557	3,443	4,328	5,140	7,034
2006	1,730	2,174	2,675	3,555	4,435	5,266	7,207
2007	1,762	2,214	2,725	3,503	4,282	5,085	6,959
2008	1,863	2,340	2,880	3,811	4,742	5,631	7,705
2009	2,181	2,740	3,372	4,283	5,195	6,169	8,441
2010	2,406	3,023	3,720	4,773	5,826	6,918	9,467
2011	2,500	3,141	3,865	4,883	5,901	7,008	9,589
2012	2,780	3,493	4,299	5,486	6,673	7,924	10,844
2013	2,841	3,570	4,394	5,634	6,873	8,162	11,169
2014	3,306	4,154	5,113	6,187	7,262	8,624	11,801
2015	3,312	4,162	5,122	6,185	7,249	8,608	11,779
2016	3,628	4,558	5,610	6,674	7,737	9,188	12,573
2017	3,732	4,689	5,771	6,834	7,898	9,379	12,834
2018	4,167	5,236	6,444	7,588	8,733	10,370	14,191
2019	4,519	5,678	6,988	8,180	9,371	11,128	15,228
2020	4,775	5,999	7,384	8,586	9,789	11,624	15,906
2021	4,823	6,059	7,458	8,672	9,886	11,740	16,065
2022	4,871	6,120	7,532	8,759	9,985	11,858	16,226
2023	4,920	6,181	7,608	8,846	10,085	11,976	16,388
2024	4,969	6,243	7,684	8,935	10,186	12,096	16,552
2025	5,019	6,305	7,761	9,024	10,288	12,217	16,718
2026	5,069	6,369	7,838	9,114	10,391	12,339	16,885
2027	5,120	6,432	7,917	9,206	10,495	12,462	17,054
2028	5,171	6,497	7,996	9,298	10,600	12,587	17,224
2029	5,222	6,562	8,076	9,391	10,706	12,713	17,397
2030	5,275	6,627	8,156	9,485	10,813	12,840	17,571

Note: The Low and high scenarios are cumulative

Source: California Energy Commission, Energy Assessments Division, 2017.

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