Appendix E to California's Compliance Plan for the Federal Clean Power Plan:

Documentation of Modeling Assumptions

This appendix describes the methodology used to construct the demand forecast, and the supply and demand assumptions and analyses used to construct the IEPR cases that underlie the CPP compliance demonstration detailed in the Compliance Plan.

Constructing the California Demand Forecast

The Energy Commission has, since the 19702, regularly developed an independent electricity and natural gas demand forecast. Although the methods to estimate energy efficiency impacts and self-generation have undergone refinement in recent years, the *CED 2015 Revised* uses the same sort of detailed sector models supplemented with single equation econometric models as previous long-term staff demand forecasts. More detailed descriptions of the sector models are available.[1] The Energy Commission's demand forecasting methodology features a variety of different sector-based models that include annual electric and natural gas consumption models and an electric hourly peak load model. In most sectors, the Energy Commission's methodology attempts to simulate individual energy use decisions as they pertain to end use energy services. Examples of energy services or end uses are heating in a home, dishes cleaned in a dishwasher, illumination from a light fixture and evaporation of water from pulp in a paper making machine. Energy in the form of natural gas and electricity (or other fuels) operates machinery to produce the service derived.

End use energy consumption estimates can be developed from the application of analytical engineering techniques and econometric techniques for extracting information from customer use data. Early generation end use models were developed using largely engineering methods. As better data became available, disaggregate econometric techniques were incorporated. The advantage of end use modeling over other forecasting techniques is the ability to explain more fully how energy is actually used and factors affecting change in energy use. For example, the Energy Commission staff uses models involving different levels of end use detail to characterize the manner in which efficiency programs affect both energy requirements and peak demand.
The Energy Commission's demand forecasting methodology is also based upon classes of energy users (households, business types, etc.) whose behavioral responses to key energy use determinants are reasonably homogeneous. Residential behavior, uses, and needs differ from those of commercial end users, just as they differ from those of industrial consumers. The sectoral groups modeled balance the desire to capture end use detail with available data resources.

The demand forecast models have been built up over the past 35+ years with data regarding sectoral and statewide estimates of aggregate energy consumption. Each demand forecast update cycle considers incremental changes to a large number of interacting variables, comparing those changes to overall sectoral and statewide trend data, calibrating potential revisions to the model to avoid contradictions to the incremental change in trend data for that update cycle.

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[1] California Energy Commission, *Energy Demand Forecast Methods Report*, June 2005, #CEC-400-2005-036. This report provides a very detailed description of the methods, models and data the Energy Commission uses in developing the demand forecast.

The Energy Commission uses five sector models along with a summary model which aggregates the energy demand requirements from the sectoral models and prepares them for input to the final model in the forecast process: the peak demand and hourly load model. The Energy Commission also developed a model to project retail electricity rates. The different models are described below.

Residential Energy Demand Forecast Model

The residential model forecasts energy demand for a number of end uses, housing types and fuel types. End uses include space heaters, air conditioners, refrigerators, color televisions, lighting, water heating, etc. Electricity and natural gas consumption are fully modeled for all relevant end uses, while saturations are maintained for other fuels (principally wood, liquid propane gas, and solar). Vintages of housing construction are used to represent the eras in which building codes and code revisions significantly influenced the thermal characteristics of residential buildings. These housing vintages are grouped by homes built before the standards were initiated in 1975 and those built in subsequent years as energy building standards became more stringent.

The residential model forecasts energy demand in three principal components. First, the number of households of each housing type is forecasted. Household projections are the main explanatory variable for the residential sector. Second, the saturation of appliances for each of three fuel types is projected. For example, the number of households having a gas space heating unit is determined. Finally, the model determines the amount of energy expected to be used by each end use appliance; this depends, in part, on the age profile of the appliance stock, as revised appliance standards have resulted in their increased efficiency over time. Total residential electricity consumption is the product of projected households, the fraction of households possessing a particular appliance, and the yearly average energy use for that appliance, summed over all end uses.

A very important element in forecasting demand for the residential and commercial sectors is capturing and incorporating state and federal building and appliance efficiency standards. A more detailed description of how the residential and commercial models address standards is provided below.

Commercial Energy Demand Forecast Model

The commercial energy forecasting model is similar to the residential model with respect to the degree of disaggregation. The model first forecasts the amount of floor space and vacancy rates for different building types. Second, the model determines the fraction of floor space in each building “saturated” with commercial equipment for electricity and other fuel types. The nature of the energy-using equipment in each building type determines the commercial end uses. For example, restaurants contain ovens and stoves, therefore, cooking is a principle end use for that building type. Finally, the amount of energy required per square foot of floor space is determined for each fuel type. The commercial model relies heavily on end use intensities, which are the energy use estimates per square foot of building type. Total commercial energy demand is the product of these three factors and summed for all end uses and building types. The model considers the effects on energy use of changes in floor space, vacancy rates, energy prices, the Energy Commission's building and appliance standards, and other major efficiency programs.

Industrial Energy Demand Forecast Model

The industrial sector is divided into process and assembly groups. Process industries primarily involve the processing of raw materials, generally by chemical or physical transformations using thermal and electrical inputs. Individual process industries include food products, wood products, pulp and paper, petroleum refining, cement and glass. Also included in this group are the extraction industries which include petroleum and natural gas extraction and mining. The assembly industry group includes industries whose primary activity is to shape and form materials and assemble components to produce final goods in a noncontinuous production environment. Covering most manufacturing, these industries are relatively electricity intensive.

Projections of industrial energy demand for most sectors except extraction industries are driven by forecasts of output [added value of shipments or gross domestic product (GDP)]. For extraction industries forecasts of employment are used because the volatility of the prices of such commodities as oil, natural gas and precious metals leads to volatility in values of shipments or GDP.

To forecast annual electricity demand the Energy Commission uses a model that can account for energy use trends, price effects and exogenous improvements in efficiency by end use and industry.[2] The major end uses in the model are motors, thermal processes, lighting, heating, ventilation and air conditioning (HVAC) and miscellaneous. Energy Commission staff use the model to project demand for electricity, natural gas and other fuels for these five major end uses over a 12 year period. Demand for electricity, natural gas and other fuels for each of these five major end uses is forecast for each process and assembly industry.

Agricultural and Water Pumping Energy Demand Forecast Models

The agricultural sector is subdivided into three subsectors: crop production, dairy and livestock production, and urban water pumping. A separate forecasting model has been developed for each subsector, although the major focus is on water pumping for crop production as this consumes more electricity than other end uses.

The crop production model consists of two econometric equations, one for the amount of electricity used to pump ground water and the other to pump surface water. The equations are based on the economics of water usage in the agricultural sector. Demand for electricity to pump water depends on the level of crop production, the price

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[2] The Energy Commission uses the Industrial End use Forecasting Model (INFORM), developed by the Electric Power Research Institute (EPRI) to forecast industrial demand.

of electricity, the price of diesel, and the amount of rainfall. In the dairy and livestock subsector, the demand for electricity is forecast in three steps. Econometric models relate energy consumption to levels of dairy and livestock production, as well as electricity prices. The levels of dairy and livestock production are forecast using econometric models or trend analyses. Forecasts of these variables are used in the estimated energy equations to generate forecasts of energy consumption.

Urban water pumping requirements are forecast by estimating econometric equations in which energy consumption for water pumping is regressed on the determinants of urban water demand. These variables include total homes, persons per household, per capita income, and cooling degree days; the most important of them is the total number of homes in each planning area.

Energy Demand Summary Forecast Model

Individual sectoral model energy demand forecasts are processed by the Energy Demands Summary Forecast Model in order to calculate planning area total forecasts. The summary model adjusts the sectoral forecasts for weather and DSM program savings. Weather adjustments are made to the residential and commercial model forecast results because these two models forecast (and backcast) on the basis of long-run normal weather. The sectoral model backcast and recorded energy consumption are not directly comparable due to the influence of abnormal weather on actual consumption. Energy demand for weather sensitive end uses is adjusted to accommodate the deviation between actual weather and normal weather for each climate zone in the planning area. After the weather adjustment, minor adjustments are performed to account for demand side management (DSM) programs which have not been incorporated into the structure of or input data used in the sectoral models. The final adjustment to the forecasts is to calibrate the results using the recorded energy consumption. Calibration is a process of "scaling" the adjusted sectoral results based on the differences between the adjusted results and recorded energy consumption.

Peak Demand Forecast Model and Hourly Electric Load

The Energy Commission staff employs the Hourly Electric Load Model (HELM) to directly use the end use electricity demand projections of the individual sectoral energy models. Projecting hourly peak load is more difficult than projecting energy consumption because the instantaneous demand for electricity changes constantly. Appliances are used more during the day than in the middle of the night (hourly change), lights are on more in the winter than in the summer (season), and refrigerators cycle more often in hot weather (temperature). Moreover, historical data on customer load consists mainly of system and sector load; relatively little customer type, or end use information is known with certainty.

HELM forecasts hour-by-hour end use demand for every day of the year. Peak days and peak hours on those days are then determined by locating maximum values from many individual hourly load forecasts. This method allows peak load to be directly determined from energy forecasts rather than constrained to follow past consumption patterns. Peak calibration is needed to compensate for discrepancies between model results and recorded peak data. In calibration, the staff takes advantage of both data on the estimated coincident peak by sector and the historical system peak. The calibration procedure compares model estimates of peak demand with the recorded peak data for a historic period.

Electricity Rate Model

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

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

The largest component of a utilities' electric revenue requirement is the cost of procuring electricity supply. This includes the cost of purchased power, capital expenditures, fuel, and operating costs for utility-owned resources. To estimate procurement costs, staff first identified energy production and costs for existing resources, either owned or under long-term contract. The cost of additional energy and capacity needed to meet each utility's stated Renewables Portfolio Standard (RPS) targets, serve load, and ensure reliability are then calculated. An average price for incremental renewable purchases is developed using levelized costs projections. Weighting each technology cost by percentage of renewable resource additions in the staff production simulation model produced a procurement price in dollars per megawatt hour ($/MWh).

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

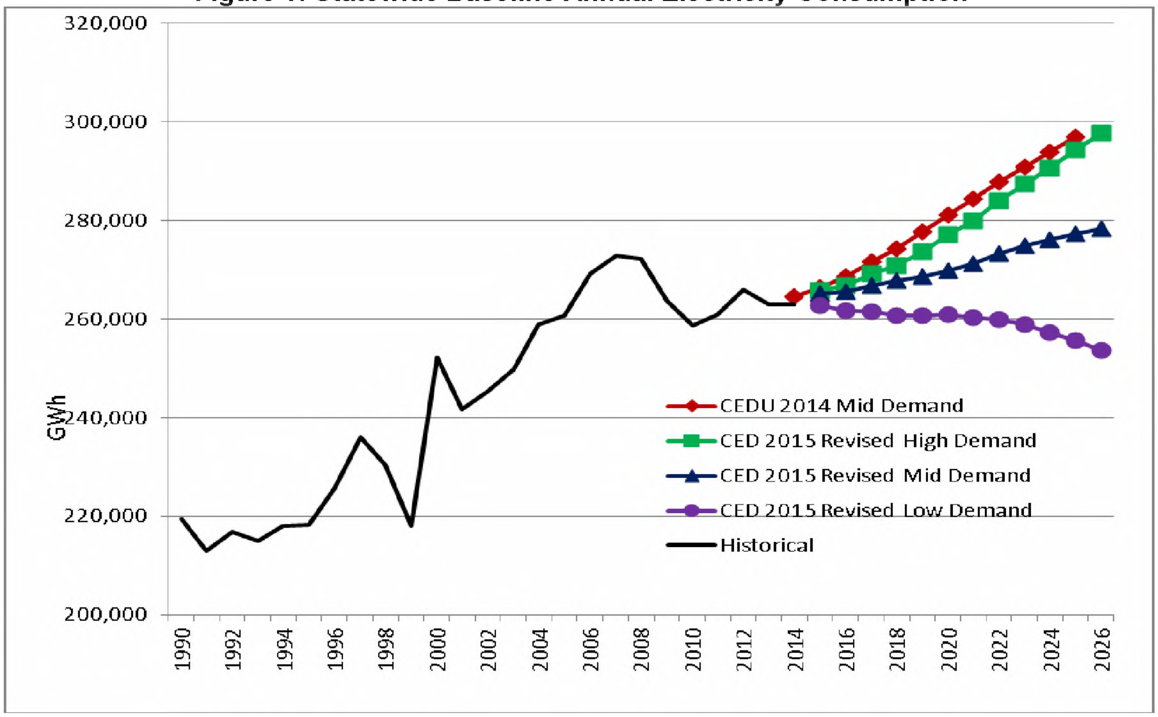
Growth in distribution revenue requirements are driven primarily by the capital investment needed to maintain and expand the distribution system and supporting infrastructure. Current data on distribution revenue requirements, collected from utility data submittals, financial statements, and board or CPUC decisions, are incorporated into the model. Transmission revenue requirements were developed using utility 2015 IEPR data submittals, recent transmission owner rate cases, and the California ISO 2015 Transmission Access Charge Forecasting Model. This includes renewables integration projects and ongoing reliability upgrades.

<u>2015 IEPR California Electricity Demand</u>

The *CED 2015 Revised* includes three baseline cases designed to capture a reasonable range of demand outcomes over the next 10 years. The high energy demand case incorporates relatively high economic/demographic growth, relatively low electricity and CO_2e prices, and relatively low self-generation and climate change impacts. The low energy demand case includes lower economic/demographic growth, higher assumed electric rates, and higher self-generation impacts.[3] The mid case uses input assumptions at levels between the high and low cases.[4] Annual growth rates from 2014-2025 for *2015 CED Revised* average 1.27 percent, 0.97 percent, and 0.54 percent in the high, mid and low cases, respectively.[5] Forecasted electricity demand in 2026 is 326,491 GWh for the high case; 314,970 GWh in the mid case and 299,372 GWh in the low case, as shown in **Figure 1**.

[3] The analysis relied primarily on the mid and the high demand case to construct the two scenarios. The one exception is the use of the high CO_2e price projections from the low demand case for California CO_2e emitting resources for the Stress Case as described earlier.
[4] These forecasts are referred to as baseline cases, meaning they do not include additional achievable energy efficiency (AAEE) savings. AAEE estimates for the investor-owned utilities (IOUs) and the two largest publicly owned utilities (POUs) are discussed later in this section.
[5] 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.

Figure 1: Statewide Baseline Annual Electricity Consumption

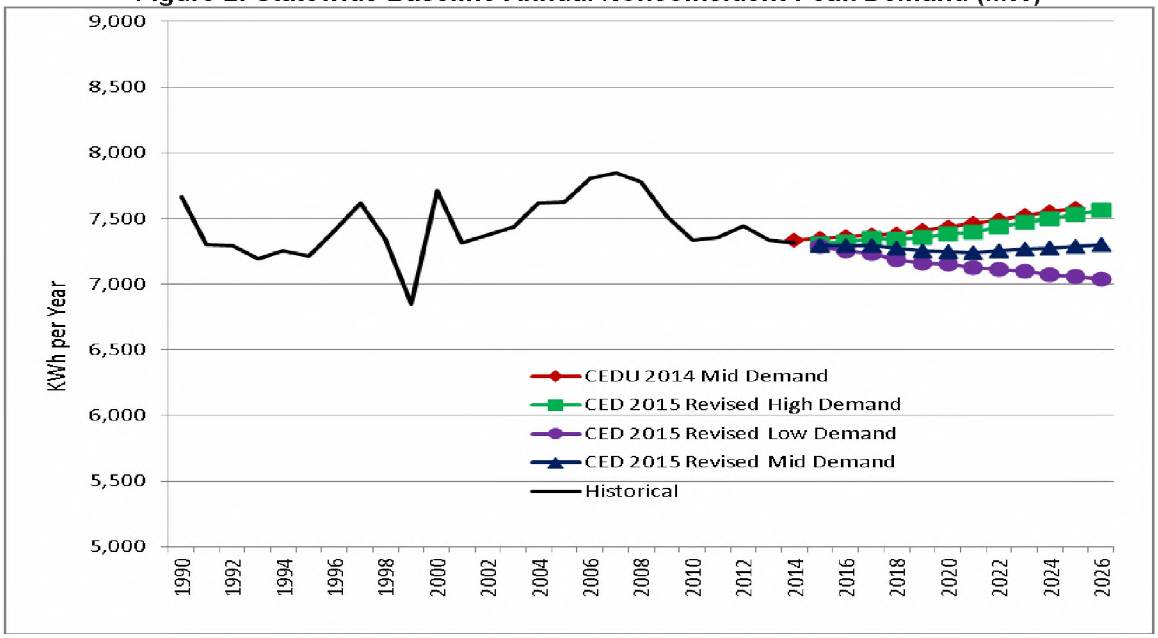


Source: California Energy Commission, Demand Analysis Office

The statewide *CED 2015 Revised* projects annual growth rate for statewide baseline non-coincident peak demand (adjusted for atypical weather) from 2015 to 2025 of 0.97 percent, 0.46 percent and -0.28 percent in the high, mid, and low cases, respectively.[6] Statewide noncoincident peak demand increases to 67,167 MW, 63,848 MW, and 59,293 in the high, mid and low cases, respectively, as shown in **Figure 2**.

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

Figure 2: Statewide Baseline Annual Noncoincident Peak Demand (MW)



Source: California Energy Commission, Demand Analysis Office

The California Energy Commission (Energy Commission or CEC) develops forecasts of statewide electricity demand as well as forecasts for eight electric utility planning/service areas. The compilation of planning area forecasts requires the aggregation of county data to the planning area level. For example, county-level housing construction, population and income estimates form the basis of a planning-area residential consumption forecast. Recent energy demand forecasts have been developed for 8 specific planning areas based on utility service territories and 16 climate zones. To better serve users of this forecast, staff has modified the planning area definitions for *CED 2015 Revised*. The new scheme is more closely based on California's electricity balancing authority areas, where resource plans must maintain the proper balance for load, transmission, and generation. As part of a continuing effort to provide more geographic granularity in the forecast results, staff increased the number of forecast (climate) zones from 16 to 20.

Economic and Demographic Inputs

Economic and demographic factors are major drivers of the demand and peak forecasts. As in previous forecasts, staff relied on Moody's Analytics and IHS Global Insight to develop the economic growth scenarios to drive the three *CED 2015 Revised* demand cases. Demographic inputs relied on these two sources as well as the California Department of Finance (DOF). For the economic inputs, staff used the IHS Global Insight Optimistic economic scenario for the high demand case, Moody's Analytics Below-Trend Long-Term Growth case for the low demand case, and Moody's Analytics Baseline economic forecast for the mid demand case. For population and number of households, the low case comes from the DOF's 2015 long-term projections, and the mid and high cases from Moody's Analytics.16 The key assumptions used by

Moody's Analytics and IHS Global Insight to develop the three economic scenarios are provided in **Table 1**.

The aggregate demand for energy services increases with growth in economic activity and population and as new energy services (frequently possible due to the emergence of new technologies) become available. The Energy Commission's demand forecasts are driven by projections of the sector-specific economic variables such as: personal income and household population for the residential sector; floor space and employment for the commercial sector; fuel prices and output by industry for industrial sector; and crop production or rainfall for the agricultural sector. In addition, updated forecasts must reflect the penetration rates at which more efficient equipment and new energy services enter into use. These key drivers of demand discussed in the following sections.

Table 1: Key Assumptions Embodied in *CED 2015 Revised* Economic Case

High Demand Case (IHS Global Insight *Optimistic* Scenario), July 2015	**Mid Demand Case (Moody's Analytics *Baseline* Scenario), July 2015**	**Low Demand Case (Moody's Analytics *Below-Trend Long-Term Growth* Scenario), July 2015**
National unemployment rate falls to 4 percent by 2018.	National unemployment rate below 5 percent through 2018.	The unemployment rate stays higher than in the baseline, just above 5 percent in early 2018.
European Central Bank's quantitative easing and the structural reforms implemented by emerging markets yield stronger foreign growth.	The Federal Reserve will normalize U.S. monetary policy by early 2018, but the European Central Bank will not be able to normalize policy until near decade's end.	The Eurozone recovery is slower than expected. Therefore, gains in U.S. exports are slow.
National light-duty vehicles sales reach more than 18.0 million in 2016.	National light-duty vehicle sales are above 16.5 million in 2016.	National light-duty vehicle sales decline to 16.2 million in 2016.
National housing starts improve to near 1.5 million units by the end of 2016.	National housing starts are expected to break 1.6 million units by 2016.	National housing starts decline to 1.2 million units by 2016.

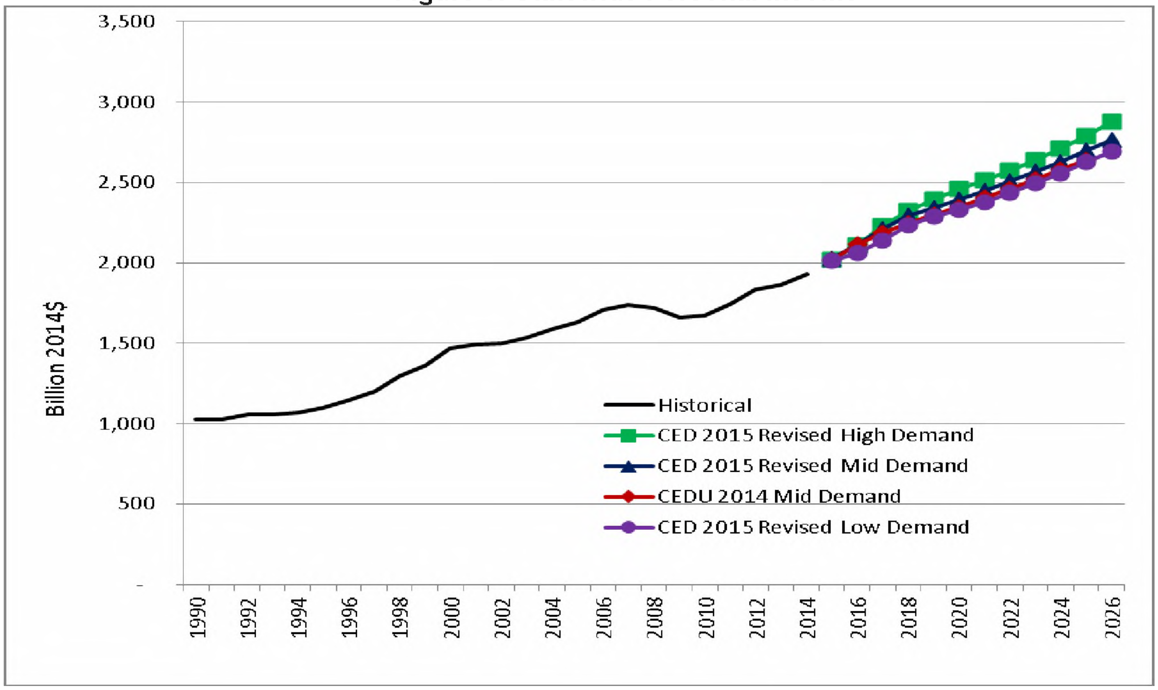
As a result of the higher demand coming with the strong global growth, oil prices initially move above their baseline. As global oil production increases in the second half of 2016, oil prices drop permanently below baseline levels.	Oil prices should slowly rebound given the pullback in investment in North American shale oil production. Global oil demand will also receive a lift from the lower prices.	Oil and gas prices fall in the short term.
With economic growth surging, the Fed raises interest rates in late 2015, and accelerates the pace starting from 2016.	The Federal Reserve has begun what is expected to be a slow process to normalize monetary policy. The first step is to end its bond-buying program, which it did in October. The Fed will begin raising short-term interest rates in late 2015. Short-term interest rates will normalize by early 2018.	Same as in mid case.
There is an expected grand bargain for social insurance in the form of higher taxes on individuals to finance the looming demographic shift of those entering retirement. The Congressional Budget Office released its long term outlook indicating that a continually rising level of federal debt relative to GDP will eventually require an increase in revenue or spending cuts.	The federal government's fiscal situation continues to improve. The deficit is expected to stabilize at just over $500 billion in the next several years. The budget deal reached at the end of 2013 to keep the government open for at least two years is holding firm. This, combined with strong tax revenue growth, has resulted in a shrinking deficit.	The pace of economic growth remains below that of the baseline for an extended time for several reasons, including a combination of much weaker exports, business investment, and housing construction.

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

Personal Income

Historical and projected personal income at the statewide level for the three *CED 2015 Revised* cases is shown in **Figure 3**. Annual growth rates from 2014-2025 average 3.42 percent, 3.10 percent, and 2.85 percent in the *CED 2015 Revised* high, mid, and low cases, respectively.

Figure 3: Statewide Personal Income

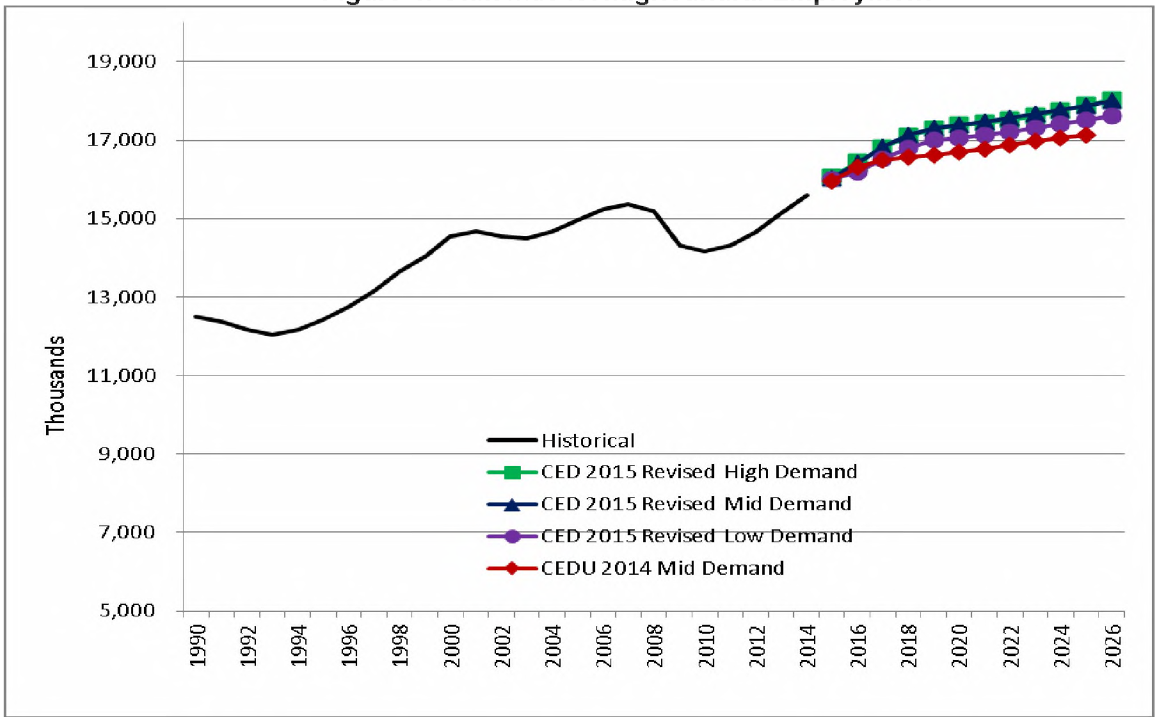


Sources: Moody's Analytics and IHS Global Insight, 2014-2015.

Employment

As shown in **Figure 4**, projected growth for statewide non-agricultural employment 2014-2025 average 1.25 percent, 1.25 percent, and 1.06 percent in the high, mid, and low cases, respectively, reflecting a slightly more optimistic view of the California economy over the next 10 years.

Figure 4: Statewide Nonagricultural Employment

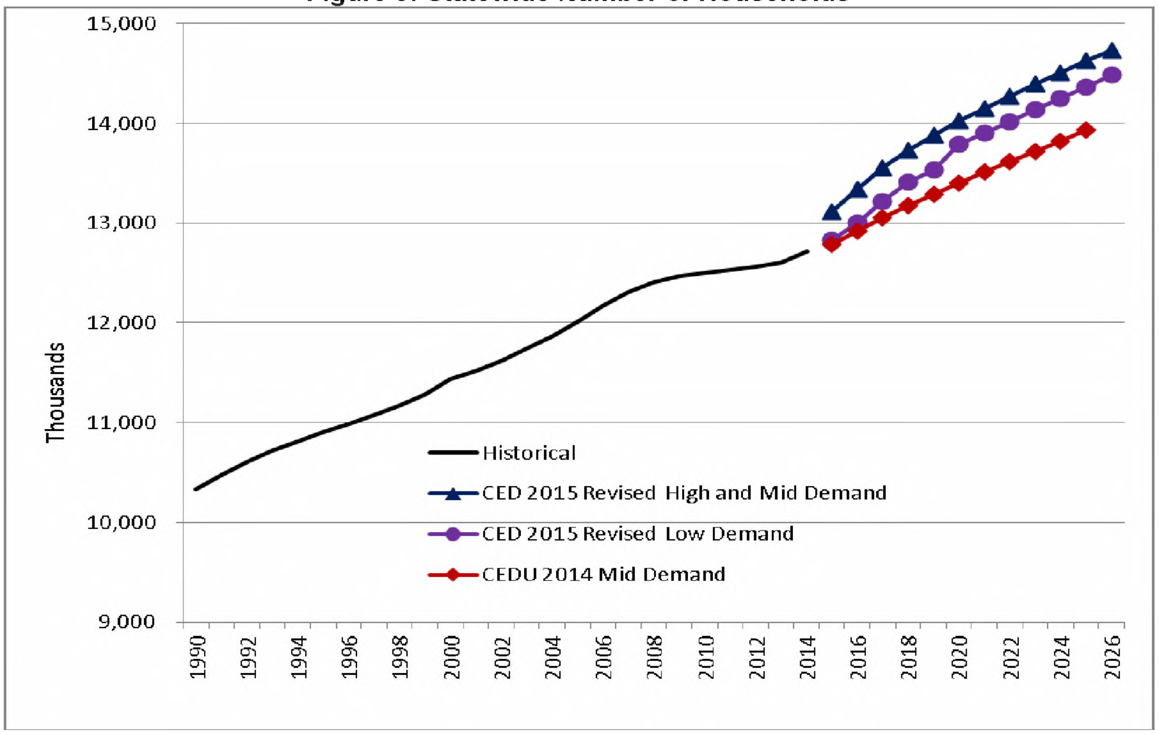


Sources: Moody's Analytics and IHS Global Insight, 2014-2015.

Households

Projections for the number of California households, the key driver for the residential forecast, are shown in **Figure 5**. The high and mid demand cases are identical and have higher projected growth in the short- term and anticipated reductions in persons per household in California, consistent with assumptions from Moody's Analytics, IHS Global Insight, and the California Department of Finance.

Figure 5: Statewide Number of Households

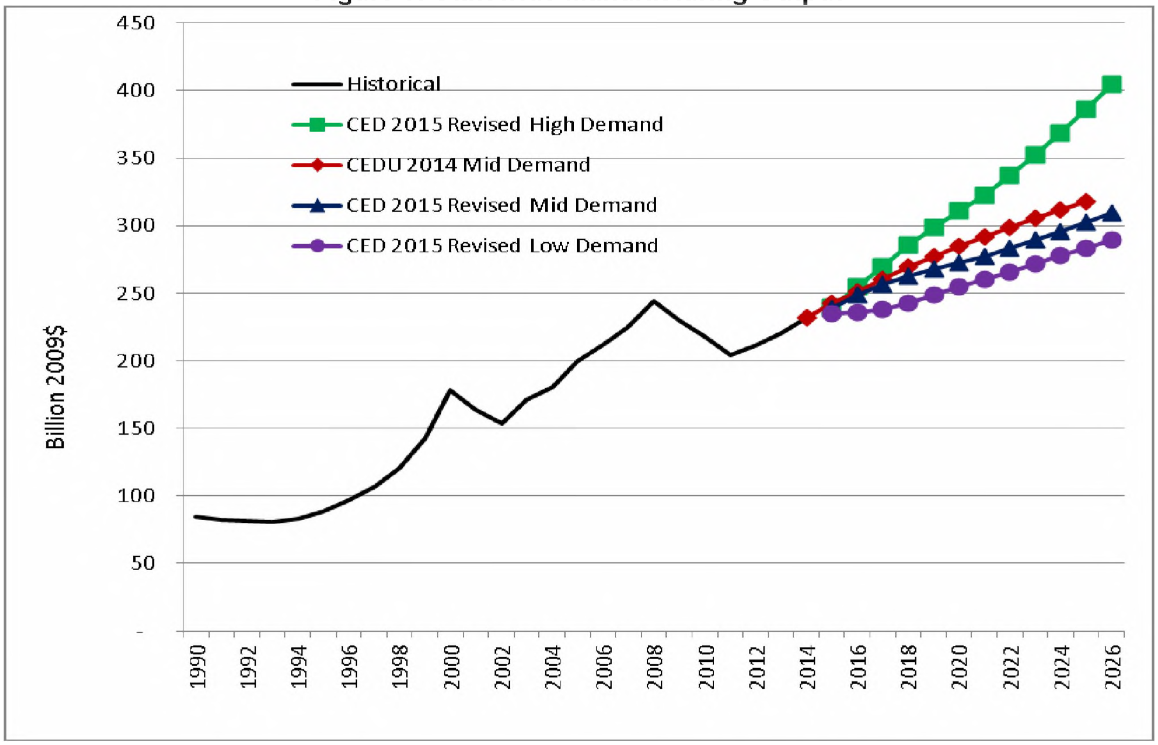


Sources: California Department of Finance and Moody's Analytics, 2014-2015.

Manufacturing Output

Historical and projected statewide manufacturing dollar output, a key driver for the industrial forecast, is shown in **Figure 6**. Annual growth rates from 2014-2025 average 4.72 percent, 2.43 percent, and 1.82 percent in the high, mid, and low cases, respectively

Figure 6: Statewide Manufacturing Output



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

Electricity Rates

The Energy Commission staff used their new rate model to generate mid, high and low rate cases that vary electricity demand, natural gas prices, and carbon prices. The low rate (high demand) case assumes high demand, low natural gas and CO_2e allowance prices, and less infrastructure investment. The high rate (low demand) case assumes lower electricity demand, higher natural gas and allowance prices, and more infrastructure investment. Electricity rate scenarios for the five major planning areas for selected years for the three major sectors by demand case are shown in **Table 2**. The effect of increasing rates on the forecast is determined by model price elasticities of demand, which average about 10 percent across the sectors.

Table 2: Rates by Demand Case for Five Major Planning Areas (2014 cents per kWh)

Planning Area	Year	Residential			Commercial			Industrial		
		High	Mid	Low	High	Mid	Low	High	Mid	Low
PG&E	2014	17.36	17.36	17.36	17.45	17.45	17.45	12.33	12.33	12.33
	2016	17.71	17.93	18.70	17.80	18.03	18.75	12.58	12.81	13.26
	2020	17.78	18.77	19.71	17.87	18.87	19.77	12.64	13.42	13.99
	2026	17.37	18.87	20.57	17.46	18.97	20.64	12.36	13.49	14.60
SCE	2014	17.19	17.19	17.19	14.66	14.66	14.66	11.67	11.67	11.67
	2016	16.78	16.90	18.03	13.92	14.08	15.17	11.35	11.45	12.28
	2020	17.19	18.38	19.62	14.07	15.05	16.27	11.67	12.53	13.38

	2026	17.33	19.34	21.57	14.23	15.46	17.26	11.83	12.92	14.16
SDG&E	2014	17.86	17.86	17.86	17.16	17.16	17.16	11.86	11.86	11.86
	2016	18.02	18.27	19.38	17.10	17.27	18.42	11.82	11.93	12.73
	2020	17.89	19.32	20.80	16.21	17.41	18.84	11.20	12.03	13.02
	2026	17.91	19.89	22.54	16.14	17.49	19.73	11.15	12.08	13.63
NCNC	2014	13.80	13.80	13.80	13.80	13.80	13.80	10.30	10.30	10.30
	2016	14.17	14.36	14.59	14.07	14.27	14.49	10.47	10.62	10.79
	2020	14.24	14.84	15.63	13.71	14.30	15.07	10.20	10.64	11.23
	2026	14.53	15.80	17.57	13.35	14.54	16.20	9.93	10.82	12.07
LADWP	2014	15.01	15.01	15.01	15.20	15.20	15.20	13.14	13.14	13.14
	2016	15.72	15.88	16.09	15.92	17.03	17.45	13.76	14.38	14.68
	2020	16.56	17.37	18.57	16.77	18.03	20.13	14.50	15.54	16.94
	2026	16.18	17.97	20.85	16.38	18.15	22.61	14.17	15.88	19.03

Source: California Energy Commission, Demand Analysis Office

Energy Conservation/Efficiency Impacts

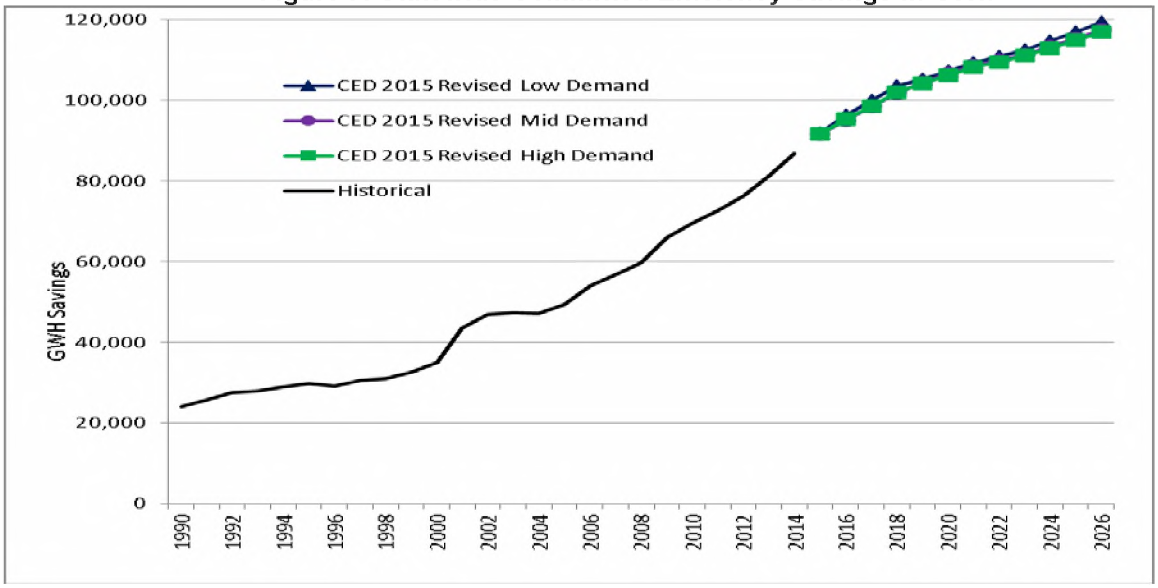
Energy Commission demand forecasts seek to account for efficiency and conservation reasonably expected to occur. Reasonably expected to occur initiatives have been split into two types: committed and additional achievable energy efficiency (AAEE). The *CED 2015 Revised* baseline forecasts continue that distinction, with only committed efficiency included.

Committed Efficiency Savings

Energy Commission staff estimate statewide projected committed electricity consumption and peak savings. Committed initiatives include utility and public agency programs, codes and standards, and legislation and ordinances having final authorization, firm funding, and a design that can be readily translated into characteristics capable of being evaluated and used to estimate future impacts (for example, a package of IOU incentive programs that has been funded by the California Public Utilities Commission (CPUC) order). In addition, committed impacts include price and other market effects not directly related to a specific initiative.

Savings are measured relative to a 1975 base and incorporate the simplifying assumption that “counterfactual” demand equals measured demand plus these savings. Within the demand cases, higher demand yields more standards savings since new construction and appliance usage increase, while lower demand is associated with more program savings and higher rates (and therefore more price effects). The net result is that savings vary inversely with demand outcome, although the totals are very similar. For electricity consumption, total efficiency savings are around 87,000 GWh in 2014, as shown in **Figure 7**.

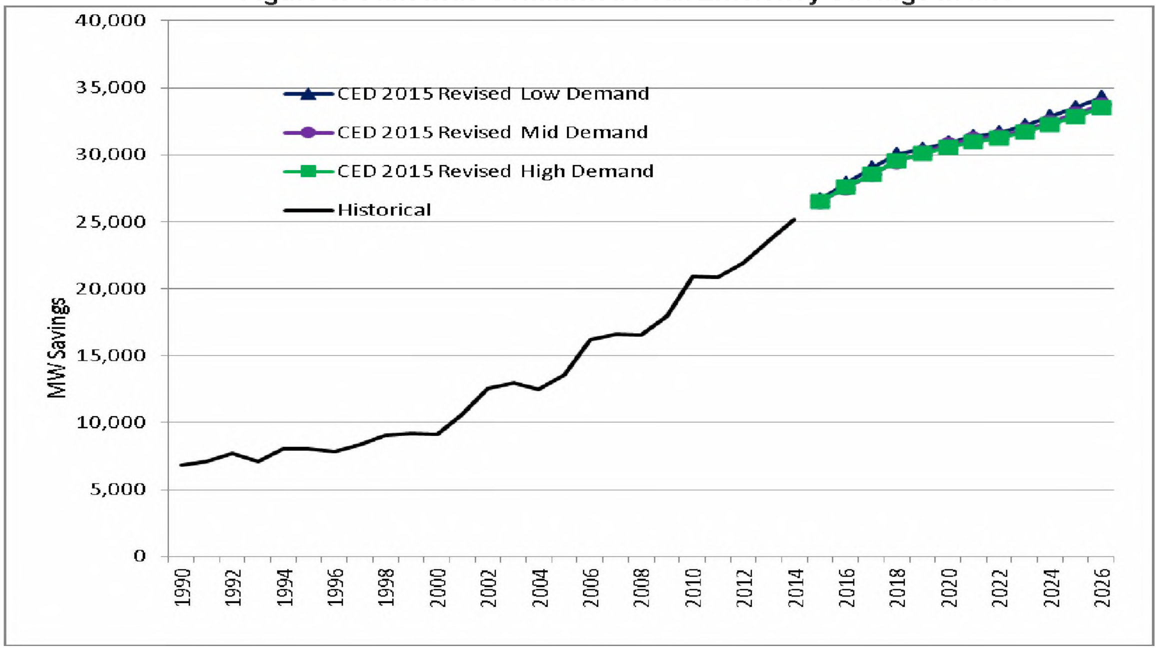
Figure 7: Statewide Committed Efficiency Savings in GWh



Source: California Energy Commission, Demand Analysis Office

Increasing rates, the addition of new programs and standards, and the continuing impacts of existing standards (as buildings and appliances turn over) push total savings to around 117,000 GWh in all three demand cases by the end of the forecast period. Peak demand savings increase to around 34,000 MW in 2026, as shown in **Figure 8** Building and appliance standards make up around 50 percent of the total in 2014 for both consumption and peak, increasing to just over 70 percent by 2026 as committed program savings decay throughout the forecast period.

Figure 8: Statewide Committed Peak Efficiency Savings in MW



Source: California Energy Commission, Demand Analysis Office

Additional Achievable Energy Efficiency for IOUs

CED 2015 Revised also includes estimates of AAEE savings for the IOU service territories and the two largest POUs. These savings are not yet considered committed but are deemed reasonably likely to occur, and include impacts from future updates of building codes, appliance standards, and utility efficiency programs expected to be implemented after 2015. A demand forecast for resource planning requires a baseline forecast combined with AAEE savings, which are savings not yet considered committed but deemed likely to occur, including impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2015. *CED 2015 Revised* provides AAEE impacts for the IOU service territories based on the CPUC's *2015 California Energy Efficiency Potential and Goals Study (2015 Potential Study)*.[7]

The *2015 Potential Study* estimated energy efficiency savings that could be realized through utility programs as well as codes and standards within the IOU service territories for 2006-2026, given current or soon-to-be-available technologies. Because many of these savings are already incorporated in the Energy Commission's *CED 2015 Revised* baseline forecast, staff needed to estimate the portion of savings from the "2015 Potential Study" not accounted for in the these forecasts. These non-overlapping savings become AAEE savings.

[7] *Energy Efficiency Potential and Goals Study for 2015 and Beyond, Stage 1 Final Report*, Navigant Consulting, prepared for the California Public Utilities Commission, September 25, 2015, Reference No.: 174655. Available at: http://www.arb.ca.gov/cc/inventory/inventory.htm

The *CED 2015 Revised* used five AAEE scenarios that were designed to capture a range of possible outcomes determined by a host of input assumptions with one scenario each assigned to the high and low demand cases and three scenarios assigned to the mid demand case.[8] The scenarios assigned to a given demand case share the same assumptions for building stock and retail rates. The scenarios assigned to the low and high case were designed to serve as bookends to keep a healthy spread among the adjusted forecasts.

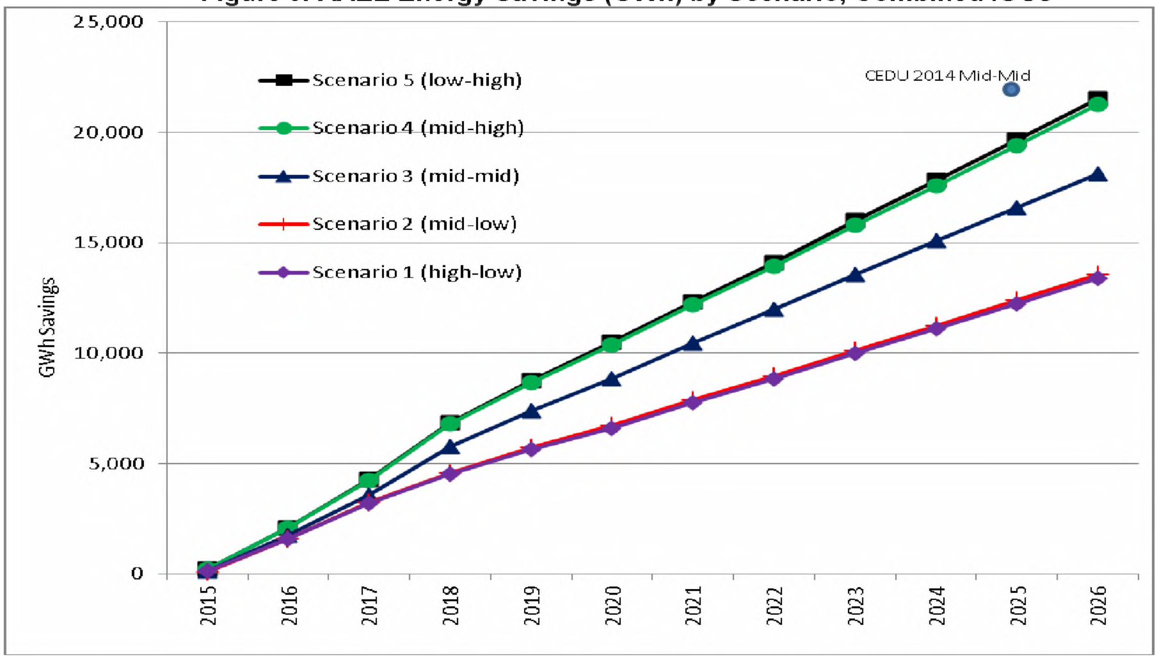
These five scenarios are thus defined by the demand case and AAEE savings scenario (high, mid, or low), as follows:

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

AAEE savings for the IOUs begin in 2015 because 2014 was the last recorded historical year for consumption in *CED 2015 Revised*. By 2026, AAEE savings reach roughly 18,000 GWh energy savings and about 4,500 MW of peak savings in Scenario 3 (mid-mid), as shown in **Figure 9** and **Figure 10**, respectively. The high savings scenarios reach around 21,500 GWh and more than 5,000 MW in 2026, while projected totals in the low savings scenarios are about 13,500 GWh and 3,300 MW. Totals for the low-high and mid-high scenarios are very similar, as are the high-low and mid-low because the impacts of building stock and electricity rates work in opposite directions and nearly offset each other.

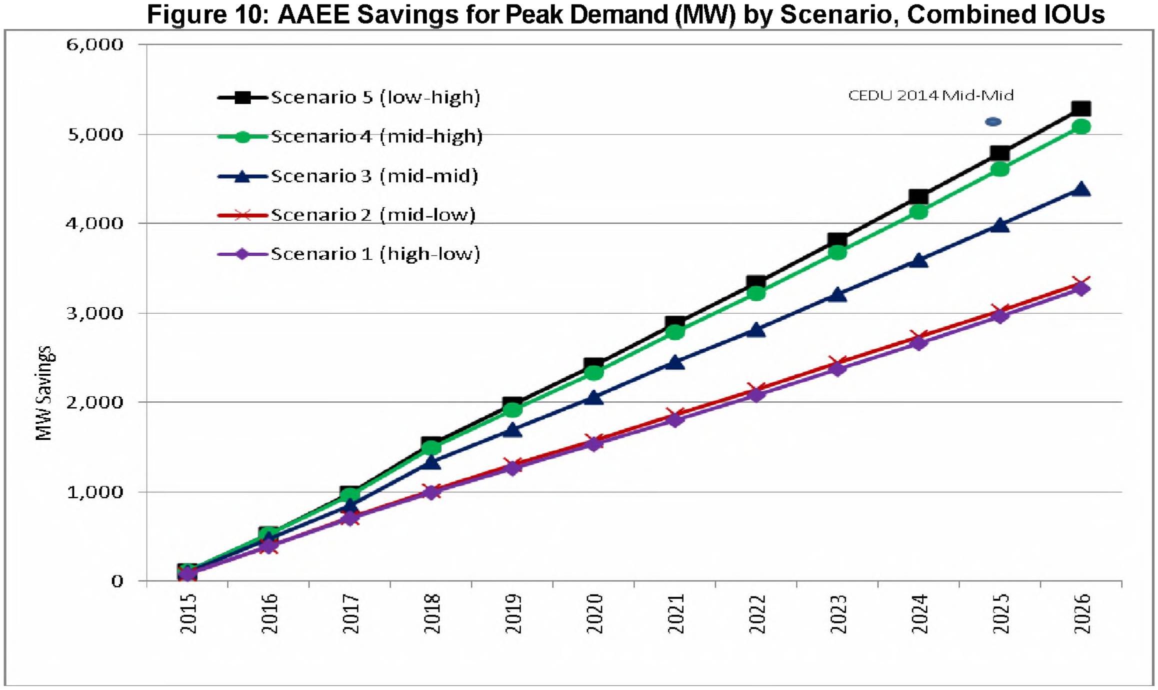
[8] The Energy Commission and Navigant developed nine AAEE scenarios that were subsequently pared down to five scenarios for use in the demand forecast.

Figure 9: AAEE Energy Savings (GWh) by Scenario, Combined IOUs



Source: California Energy Commission, Demand Analysis Office

Figure 10: AAEE Savings for Peak Demand (MW) by Scenario, Combined IOUs



Source: California Energy Commission, Demand Analysis Office

Table 3 provides the total combined IOU AAEE savings by type in 2026 for all five scenarios. The standards proportion of savings is lowest in the low savings scenarios (1 and 2) since a smaller number of standards updates are included.

Table 3: Combined IOU AAEE Savings by Type, 2026

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

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

Additional Achievable Energy Efficiency for POUs

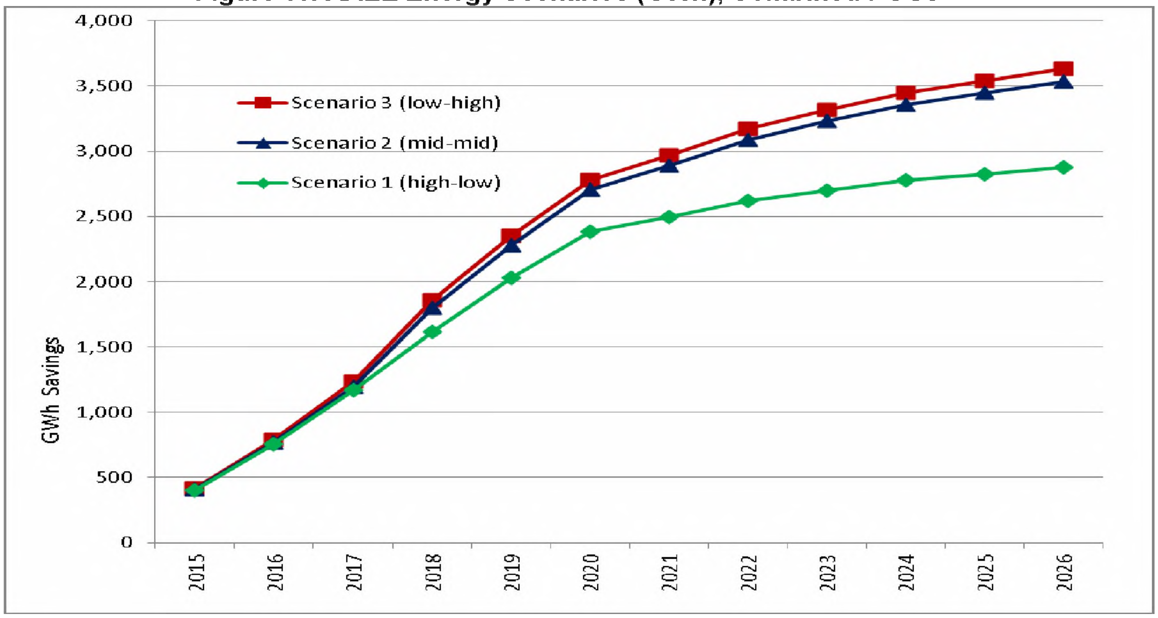
Although POUs are not required to use the IEPR demand forecasts for resource planning, the Energy Commission undertakes statewide analyses for renewables and transmission planning. In this report, staff has made the first attempt to provide adjusted, or managed, forecasts for POUs. For *CED 2015 Revised*, staff includes AAEE estimates for the Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD), the two largest POUs.
For future appliance and building standards, staff used the same basic method as Navigant Consulting in estimating savings within a given scenario. Estimated statewide savings from state and federal sources were downscaled to the LADWP and SMUD service territories at the sector level. For building standards, commercial floor space and number of household projections (relative to statewide totals) were used to downscale building standards in the commercial and residential sectors, respectively. For appliance standards, statewide savings were downscaled based on projected sector electricity usage in the service territory versus the state. These calculations provided high, mid, and low scenarios consistent with Navigant Consulting's estimates for the IOUs, as well as consistent with *CED 2015 Revised* baseline demand case assumptions.
Scenarios are then defined as follows:

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

Figure 11 and **Figure 12** show estimated AAEE savings by scenario for LADWP and SMUD combined for energy and noncoincident peak demand, respectively. Savings reach around 3,500 GWh and more than 900 MW in the mid and high savings scenarios and a little under 3,000 GWh and 800 MW in the low savings scenario. The mid and high savings scenarios are similar since standards savings does not differ significantly.

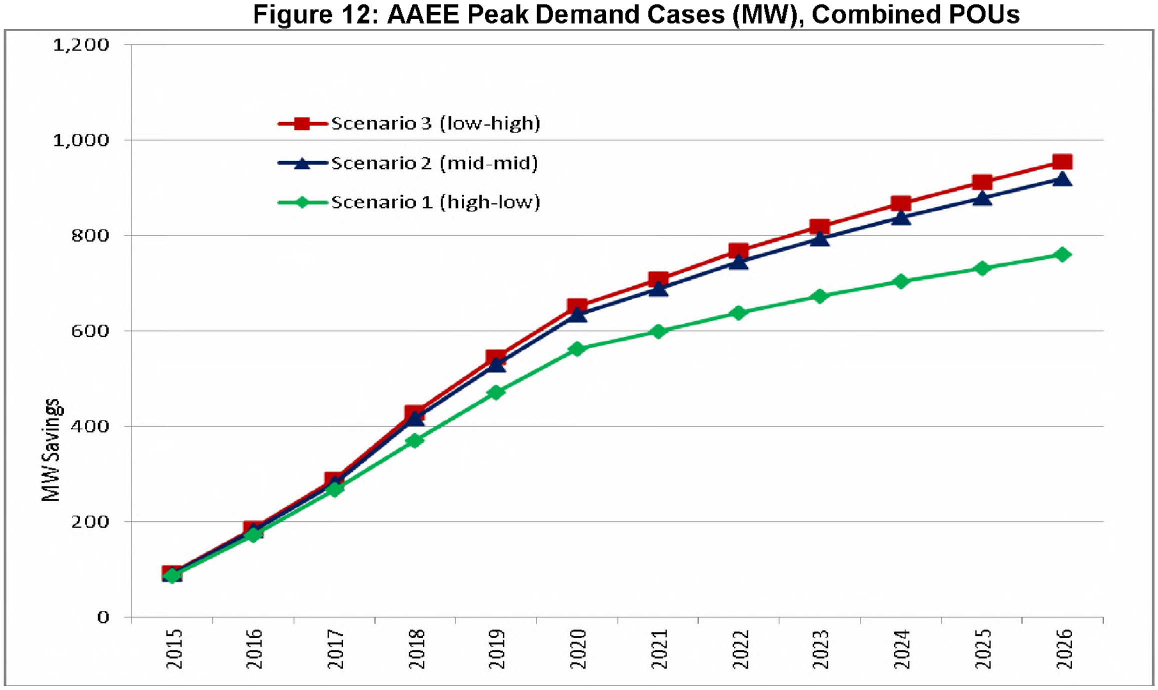
The kink in each of the curves in 2020 reflects the assumption of constant rather than growing program savings for LADWP after this year.

Figure 11: AAEE Energy Scenarios (GWh), Combined POUs



Source: California Energy Commission, Demand Analysis Office

Figure 12: AAEE Peak Demand Cases (MW), Combined POUs



Source: California Energy Commission, Demand Analysis Office

Table 4 shows combined POU AAEE savings for the three scenarios by type in 2026.

Table 4: Combined POU AAEE Savings by Type, 2026

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

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

Self-Generation

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

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

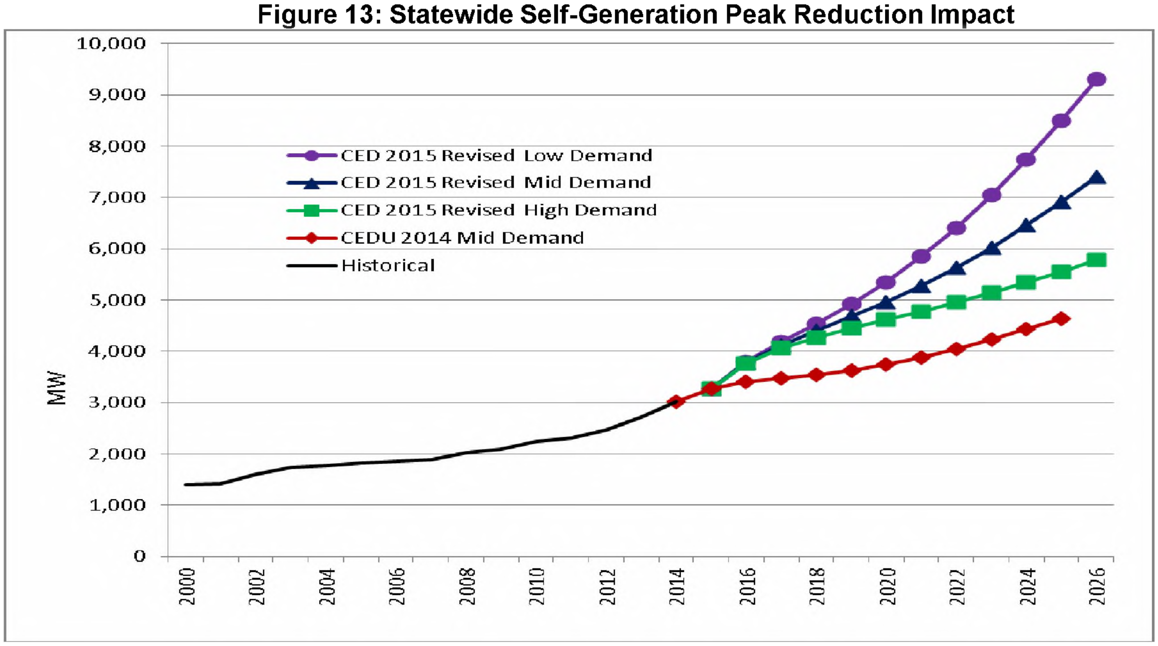
The ERP and NSHP are managed by the Energy Commission, and the CSI and SGIP by the CPUC. The general strategy of the ERP, NSHP, CSI, and SGIP programs is to encourage demand for self- generation technologies, such as PV systems, with financial incentives until the size of the market increases to the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

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

Commercial PV adoption is modeled similarly to residential, with adoptions developed by building type (hospitals, schools, and so on). The same predictive model is used to forecast commercial combined heat and power (CHP) technologies, employing estimated load shapes by building type. Results for adoption in both the commercial and residential sectors differ by demand cases since projected electricity and natural gas rates and numbers of homes vary across the cases. Lower electricity demand corresponds to higher adoptions since the effect from higher rates outweighs lower growth in households. Self-generation for other technologies and sectors is projected using a trend analysis and does not vary by demand case.

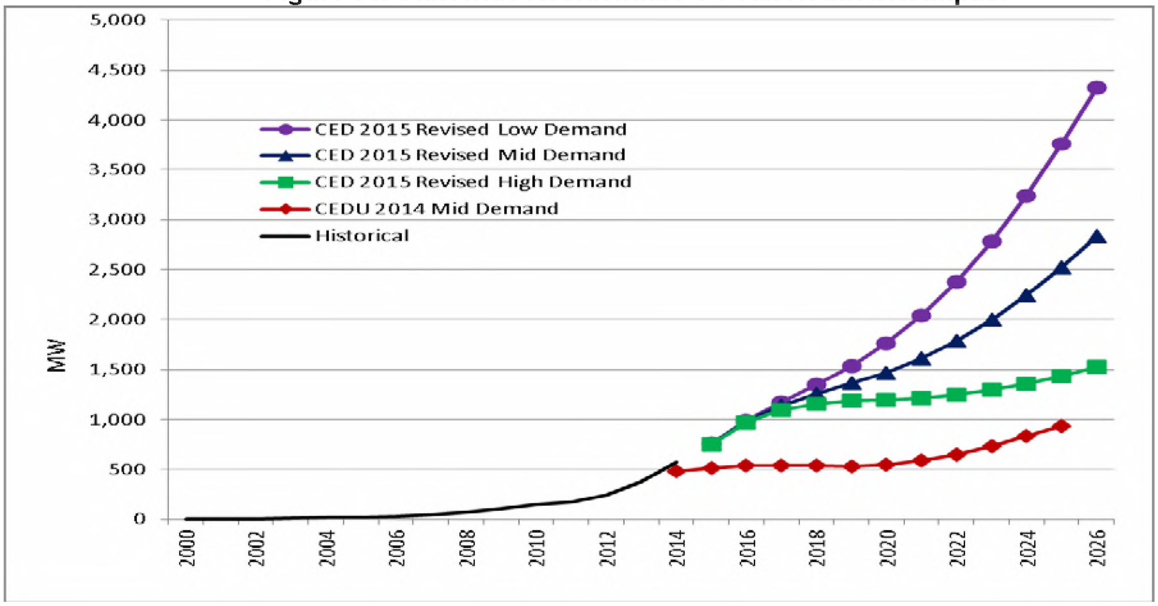
Historical and projected peak reduction impacts of self-generation for the three *CED 2015 Revised* demand cases mid case are shown in **Figure 13**. Self-generation is projected to reduce peak load by more than 6,900 megawatts (MW) in the new mid case by 2025. Residential PV is a key factor in this increase, as shown in **Figure 14**. By 2026, residential PV peak impacts reach almost 3,000 MW in the *CED 2015 Revised* mid case, corresponding to more than 7,700 MW of installed capacity.

Figure 13: Statewide Self-Generation Peak Reduction Impact



Source: California Energy Commission, Demand Analysis Office

Figure 14: Statewide Residential PV Peak Reduction Impact



Source: California Energy Commission, Demand Analysis Office

Light-Duty Plug-In Electric Vehicles

CED 2015 Revised incorporates scenarios for fuel consumption by on-road electric light- duty vehicles, including battery electric and plug-in hybrid electric.[9] Case results are generated with a discrete choice model for light-duty vehicles and depend on current and projected vehicle attributes (price, fuel efficiency, performance, and so on) for numerous classes and vintages of conventional and alternative fuel vehicles.

The mid case for EVs was developed to be consistent with a "most-likely" case for compliance with California's zero-emission vehicle (ZEV) regulation, provided by ARB staff. To reach ZEV levels of EV purchase, staff reduced projected EV prices, using a trajectory designed to match gasoline vehicle prices for similar classes by 2050, and increased an EV preference parameter over time within the vehicle choice model.[10] The high case assumes the increased EV preference parameter as well as EV prices that match those of similar gasoline vehicles by 2030. The low case represents "business as usual," so that electric vehicle prices stay well above those of gasoline vehicles and general consumer preference toward EVs remains constant over the forecast.

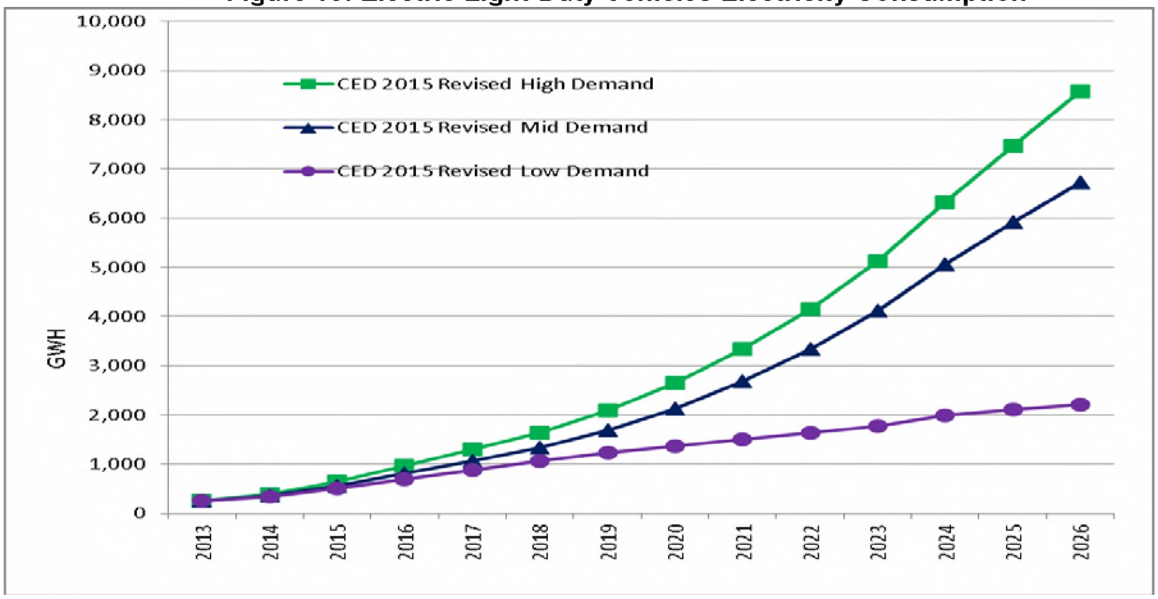
The resulting forecast cases for electricity consumption statewide by EVs in the three CED 2015 Revised cases are shown in **Figure 15**. These projections assume that EVs

[9] *Transportation Energy Demand Forecast 2016-2026, Staff Draft Report,* California Energy Commission. Publication Number: CEC-*200*-2015- 008-SD.

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

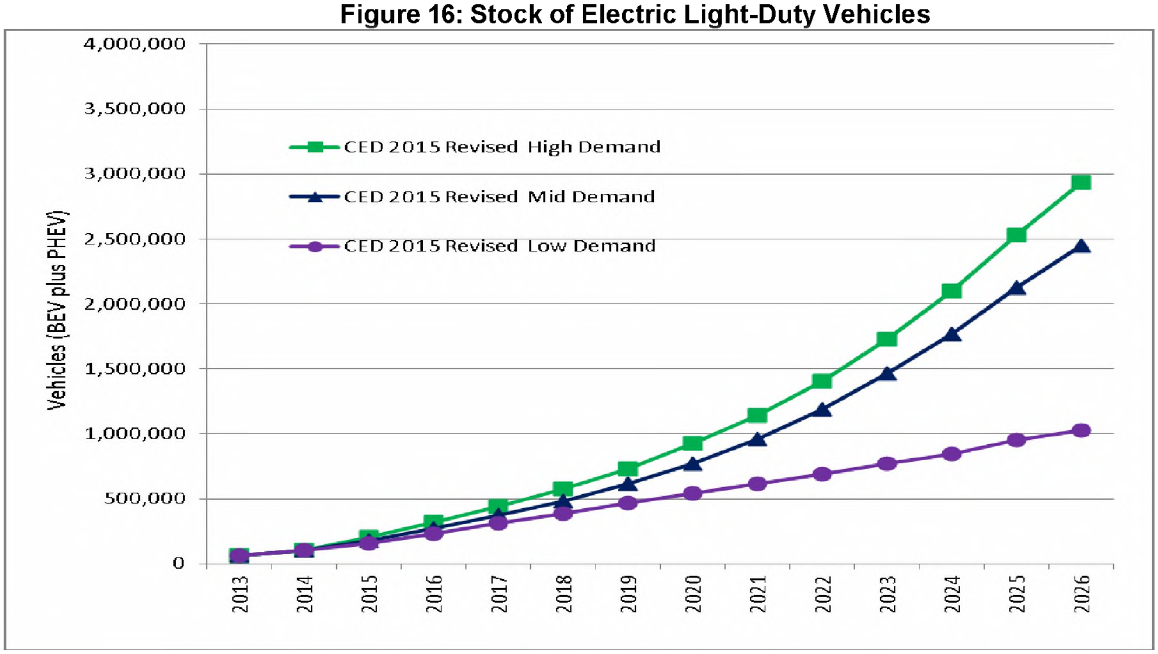
and gasoline vehicles have similar annual mileage.[11] **Figure 16** shows the associated EV stock for the three cases, which reaches around 2.5 million in the mid case by 2026.

Figure 15: Electric Light-Duty Vehicles Electricity Consumption



Source: California Energy Commission, Demand Analysis Office

Figure 16: Stock of Electric Light-Duty Vehicles



Source: California Energy Commission, Demand Analysis Office

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

Additional Electrification

Significant increases in other transportation-related electricity use in California are expected to occur through port, truck stop, and other electrification. In particular, regulations implemented by the ARB are aimed at reducing emissions from container, passenger, and refrigerated cargo vessels docked at California ports.[12] Early in 2015, the Energy Commission hired a consultant to develop projections of off-road transportation electrification, and these are incorporated in *CED 2015 Revised*.

The consultant study examined the potential for additional electrification in airport ground support equipment, port cargo handling equipment, shore power, truck stops, forklifts, and transportation refrigeration units.[13] The consultant study includes high, mid and low cases, representing aggressive, most likely, and minimal increases in electrification, respectively.[14] The cases vary by the percentage electrification assumed for off-road vehicles or applications.

Electrification impacts from the study were quantified at the state level. To incorporate them into the baseline forecast, it was necessary to allocate impacts across sector and planning area. Electrification impacts from port cargo handling equipment, shore power, truck stop electrification, and airport ground support were added to the transportation, communication, and utilities sector. Impacts for transport refrigeration units and forklifts were assigned to multiple sectors, including industrial, utilities, and certain commercial building types. Given that some portion of electrification is already embedded in *CED 2015 Revised* through extrapolation of historical trends, staff estimated incremental impacts of the consultant study projections.[15] 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 5**. Most of the impacts come from forklifts and shore power; together these applications account for around 80 percent of the total.

Table 5: Additional Electrification, Statewide (GWh)

Yea	PG&E	SCE	SDG&
2015	11	20	0
2016	26	20	12

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

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

[14] The projected vehicle/equipment populations for the various applications in this study are based on macroeconomic growth data from the U.S. Bureau of Economic Analysis, Moody's Analytics and IHS Global Insight for California applied to current populations.

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

2017	29	25	13
2018	30	28	14
2019	31	28	14
2020	32	28	14
2021	33	28	14
2022	34	28	14
2023	35	27	14
2024	36	27	14
2025	36	27	14
2026*	36	27	14

Source: California Energy Commission, Demand Analysis Office

Demand Response

The term "demand response" encompasses a variety of programs, including traditional direct control (interruptible) programs and new price-responsive demand programs. Nonevent-based programs are not activated using a predetermined threshold condition, which allows the customer to make the economic choice whether to modify usage in response to ongoing price signals. Impacts from committed nonevent-based programs have traditionally been included in the demand forecast. Nonevent-based-program impacts are likely to increase in the coming years, and expected impacts incremental to the last historical year for peak (2015) affect the demand forecast. Utility data (submitted to the CPUC) was used to identify impacts from committed nonevent demand response programs, which include real-time or time-of-use pricing and permanent load shifting. Impacts are shown in **Table 6**.

Table 6: Estimated Nonevent-Based Demand Response Incremental Program Impacts (MW)

Yea	PG&E	SCE	SDG&
2015	11	2	0
2016	26	2	12
2017	29	2	13
2018	30	2	14
2019	31	2	14
2020	32	2	14
2021	33	2	14
2022	34	2	14
2023	35	2	14
2024	36	2	14
2025	36	2	14
2026*	36	2	14

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

The demand forecast incorporates two types of dispatchable or event-based programs, critical peak pricing and peak-time rebate programs. Projected peak impacts from critical peak pricing and peak-time rebate programs, based on the IOU demand response filings, are shown in **Table 7** by IOU.

Table 7: Estimated Demand Response Program Impacts (MW): Critical Peak Pricing and Peak-Time Rebate Programs

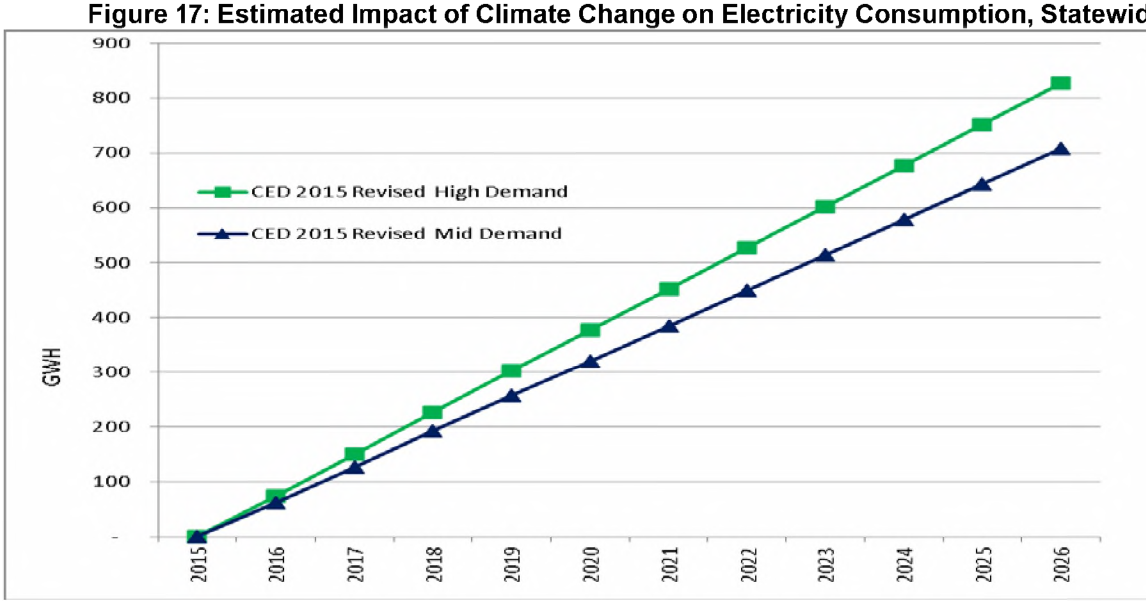
Yea	PG&E	SCE	SDG&
2015	83	27	31
2016	100	27	40
2017	107	50	41
2018	109	39	42
2019	109	42	42
2020	109	46	43
2021	109	50	43
2022	109	54	43
2023	110	59	44
2024	110	62	44
2025	110	67	45
2026*	110	67	45

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

Climate Change Impacts

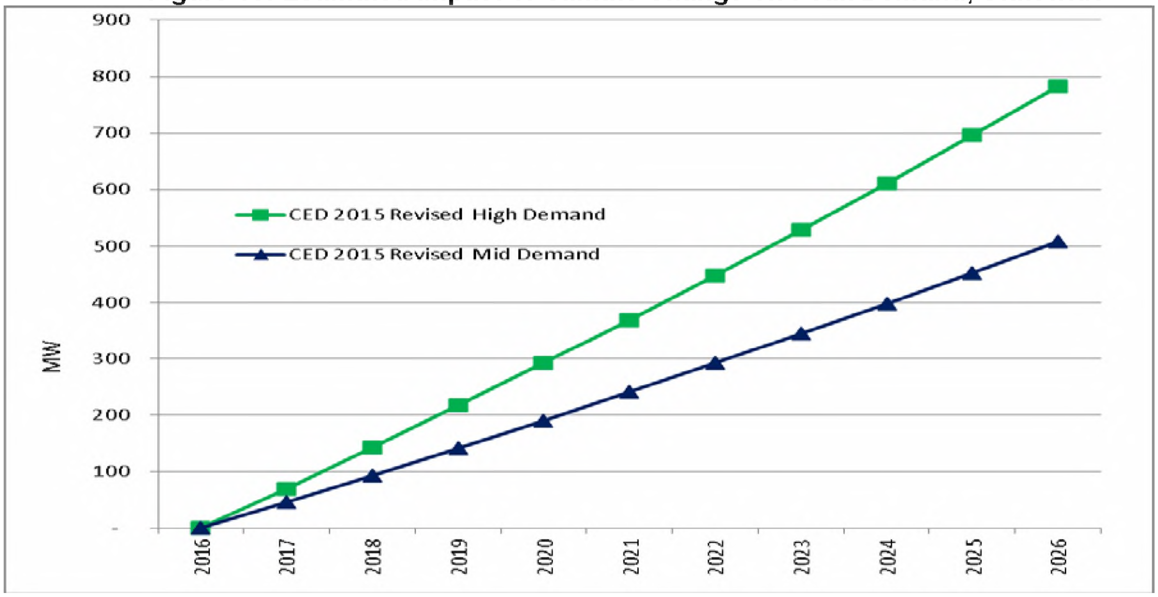
Climate change has the potential to increase electricity consumption and peak demand. Staff developed high, mid and low cases based on temperature cases developed by the Scripps Institute of Oceanography. **Figure 17** and **Figure 18** show estimated climate change impacts on statewide electricity consumption and peak demand, respectively.

Figure 17: Estimated Impact of Climate Change on Electricity Consumption, Statewide



Source: California Energy Commission, Demand Analysis Office

Figure 18: Estimated Impact of Climate Change on Peak Demand, Statewide



Source: California Energy Commission, Demand Analysis Office

2015 IEPR Power System Modeling Assumptions

For the *2015 IEPR*, Energy Commission staff simulated the WECC-wide power system to estimate a range of fuel demands for natural gas generation resources for the period of 2015 – 2026. The following describes the methods and assumptions used in developing the three natural gas cases for the 2015 IEPR, which were used as the starting point for building the reference and stress cases analyzed for CPP compliance.

The Energy Commission staff used the production cost simulation software PLEXO to estimate natural gas demand in the power generation sector for the entire WECC.[16] In this platform, staff developed a WECC-wide production simulation model dataset covering the years 2015-2026 for the three *IEPR* demand cases discussed in the previous sections. As previously discussed, simulation tools, such as the PLEXOS software, are useful tools for estimating the dispatch of the power system given a number of simplifying assumptions to approximate how the electricity system might function under given conditions. However, the actual unit-level dispatch of the future electricity market depends on unknowable market factors. Energy Commission staff closely reviewed plant by plant simulations results and found them to be robust with a few minor exceptions. For groups of plants, as a whole, Energy Commission staff is confident in the results given the assumptions. As previously stated, future details from simulation models on a plant by plant basis are should not be considered precise forecasts, however the aggregate for similar types of plants is robust.

For the *2015 IEPR*, the PLEXOS simulation dataset uses two major sets of assumptions, California-specific and those for the rest of the WECC. Each has a set of

16 The WECC Region extends from Canada to Mexico and includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California, Mexico, and all, or portions of, 14 western states in the United States of America.

electricity load forecasts and supply portfolios. California's electricity supply and demand assumptions reflect current policy and mandates. For the rest of the WECC, staff begins with the Transmission Electric Planning and Policy Committee's (TEPPC) 2024 common case and the most current year (2013) of historical supply and demand data to develop the 2015 – 2026 details missing from the single year TEPPC common case. [17]

For the 2015 IEPR, Energy Commission staff constructed WECC-wide datasets that correspond with three general conditions reflected in the demand cases (high, mid and low) discussed in the previous sections. **Table 8** outlines the specific trends that are incorporated into the model dataset for the 2015 IEPR common cases including demand, fuel price, energy efficiency, CO_2e prices and other factors affecting supply portfolios, plus how they were combined for the different cases. For example, the combination of high demand and low prices would likely result in a high level of renewable generation largely because the amount of renewable generation needed to meet the RPS is based on a percentage of retail sales. In contrast, under a low demand and high price case, renewable levels would be lower as retail sales are lower, but levels of energy efficiency would be higher since investments in energy saving equipment would be more cost-effective with higher prices.

Table 8: Trends by Natural Gas Cases

Key Assumptions Specific to Production Cost Model	High Demand Case	Mid Demand Case	Low Demand Case
Demand Forecast	High	Mid	Low
Renewable Generation	High	Mid	Low
Additional Achievable Energy Efficiency	Low	Mid	High
New CHP	None	Mid	High
Carbon Price	Low	Mid	High
Coal Price	Low	Mid	High
Natural Gas Price	Low	Mid	High

Source: California Energy Commission, Supply Analysis Office[18]

Demand Assumptions

As discussed in an earlier section, staff used the *CED 2015 Revised* as the source of California electricity demand for the forecast period. For the rest of WECC, staff relied

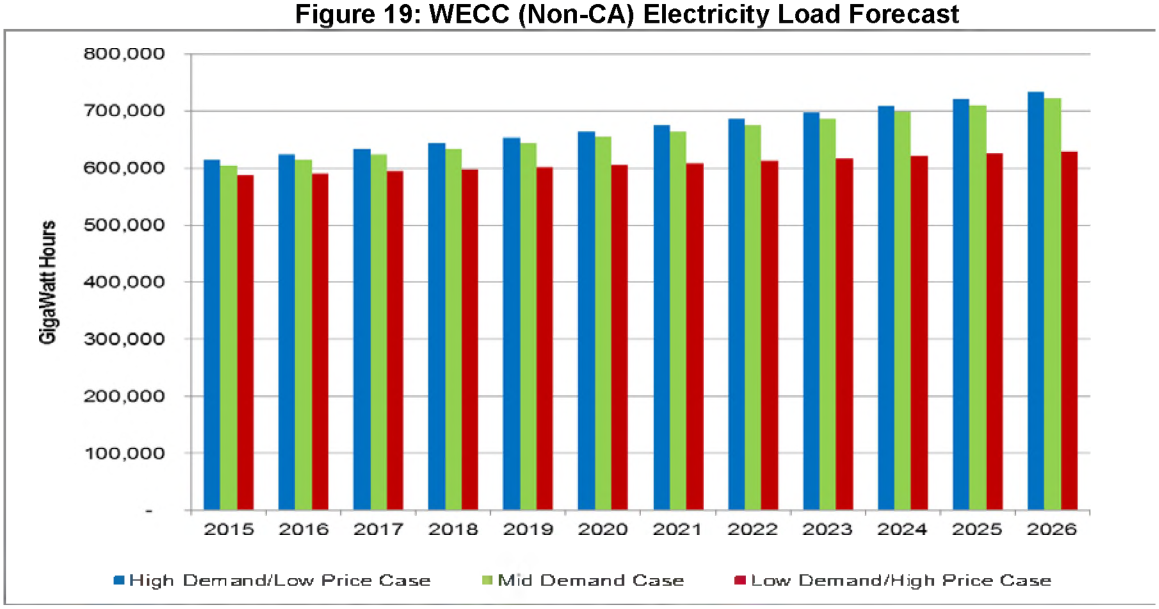
17 The TEPPC, a WECC Board of Directors committee, guides WECC's Transmission Expansion Planning (TEP) process and working groups consisting of stakeholders throughout the WECC to create this common case on a biannual basis.

18 See https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03Demand Assumptions.

on data submitted to the WECC by balancing area authorities (BAA) for the historical year 2013 and the WECC TEPPC 2024 common case load forecast were used as "bookends" to estimate the non-California BAA load. [19] Staff used a compound annual growth rate formula to calculate the peak and energy demand for the intervening years (2015 to 2023). The simulated period extended beyond the TEPPC common case year of 2024, therefore staff used the compound annual growth rate to extrapolate the annual energy and peak forecast by two years to 2026. These forecasts were inputs to the simulation software along with and hourly profile to model WECC-wide regional loads.[20]

Staff developed peak and energy forecasts for the high demand/low price and low demand/high price cases using different multipliers for each BAA. To calculate the high demand/low price case energy, gigawatt hours (GWh) forecast, staff increased annual loads by an average of 1.15 percent above the mid demand case for each year. This was based on 2013 IEPR out-of-state load forecasts. Staff used these load modifiers in the interest of time. Staff decreased the low demand/high price case annual energy forecast below the mid demand case by 8 percent, on average. **Figure 19** displays the annual WECC (Non-CA) load forecast in GWh for the period of 2015 – 2026 for all three common cases. Staff calculated annual peak demand for each BAA using the same method.

Figure 19: WECC (Non-CA) Electricity Load Forecast



Source: California Energy Commission, Supply Analysis Office

19 See http://www.wecc.biz/committees/BOD/TEPPC/Pages/TAS_Datasets.aspx.

20 Staff used the "build" function, a linear programming model that uses the peak and energy forecast and an average hourly load profile for load-serving entities in the WECC to develop hourly profiles for 2015 – 2026.

California's In-State and Out-of-State Supply Portfolio

California's electricity supply portfolio is composed of in-state and out-of-state generation resources that provided a combined total of more than 292,000 gigawatt hours (GWh) of electricity in 2014. Various conventional and renewable types of generation supply California including, natural gas-fired, hydroelectric, solar, wind, nuclear, biomass, and coal-fired resources. The composition of generation resources is expected to evolve over the next decade.

Imported coal-fired generation is expected to decline as many of California's utilities divest from coal plants. Coal plants in the west are expected to play a less prominent role in supply portfolio as some plants reach the end of their useful life and others respond to environmental regulations. Renewable generation is expected to increase its contributions to California's, and the West's, electricity supply. Continued reliance on natural gas-fired generating resources is expected throughout the forecast period to help maintain planning reserve margins and to help integrate increasing amounts of renewable resources.

Hydroelectric Generation Resources

Drought conditions in the western United States and federal and state regulations concerning water flows for fish protection have changed the overall hydroelectric generation trend in the West. This required a departure from the previous *IEPR* modeling technique, such that staff developed WECC-wide hydroelectric generation forecasts using a shorter and more recent set of historical hydro generation data from the U.S. EIA and the Energy Commission's *Quarterly Fuels and Energy Report* (*QFER*) database.[21]

Historically, staff has used the hydroelectric generation data from 1991 to the most recent year for which data are available (currently 2014). For this IEPR cycle, staff used hydroelectric generation data from 2001 to 2014 to calculate the average monthly generation by state in WECC. Using this much shorter and recent period resulted in a decrease of about 6 percent to annual hydro generation on a WECC-wide basis.[22]

Energy Commission staff also made adjustments to California hydro generation to reflect more recent drought conditions in the state. The annual projections for California hydroelectric generation are an average based on plant level 2000 – 2014 monthly historical generation and total about 31,000 GWh for the Reference Case. As a proxy for lower hydro generation in the Stress Case simulations Staff used actual 2013 hydro generation of 22,000 GWh throughout the forecast period.[23]

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21 See http://www.eia.gov/electricity/monthly/.

[22] Due to a lack of available data, staff did not update the Canadian hydroelectric generation forecast for Alberta and British Columbia.

[23] Similar de-rates to reflect more recent drought conditions were not made for the rest of WECC.

Renewable Generation Resources

Renewable energy procurement mandates in California have driven development of new renewables in CA and beyond. Staff assumes that California meets an RPS goal of 33 percent of retail sales by 2020.[24] Although recent legislations increased this renewable procurement goal to 50 percent by 2030, guidelines and regulations to implement the new law are under development and assumptions regarding specific achievement of this goal have not been included.[25] It was assumed that California maintains a minimum of 33 percent through 2026. Using the following assumptions, staff developed annual estimates for new renewable generation for each of the demand cases.

Developing a Renewable Portfolio

The method used to develop the renewable portfolio for California and the rest of the WECC was similar for all three common cases. The resource portfolio essentially adds new renewable generation such that the magnitude of renewable generation achieves policy and development assumptions across the WECC. The assumptions include the following:

- California achieves and maintains RPS of 33 percent by 2020 as a floor through 2026. Other WECC states achieve their individual RPS targets, growing linearly until the target is achieved.
- New projects were chosen using input from CPUC's RPS calculator and load-serving entities RPS procurement contracts. Staff assumed in-state renewables to continue to provide 70 to 85 percent of the total California's RPS mandated procurement, consistent with historical generation and out-of-state procurement.
- In the low demand case where the RPS procurement target decreases due to the low demand growth combined with energy efficiency and combined heat and power assumptions staff assumed contracts with out-of-state projects would not be renewed and in-state renewable energy development would occur only to maintain the 33 percent procurement floor.
- For each state without an RPS target or mandate, staff assumed existing renewable energy generation to continue operating. Staff also added additional renewable generators following general assumptions regarding new development consistent with the WECC TEPPC 2024 Common Case (Version 1.5).
- Staff assumed existing renewables continue operating at average historical levels except where information about facility retirement, refurbishment, or repowering was available. Staff assumed there were no unplanned retirements.
- Staff used annual generation reported to the QFER to infer operation characteristics (such as net capacity rating, scheduled maintenance outages, etc.) for biomass and geothermal projects.

[24] Senate Bill X1-2, Statutes of 2011 (Simitian)
[25] Senate Bill 350, Statutes of 2015 (DeLeon)

- Renewable portfolios were adjusted from the mid demand case both in- and out-of-state to meet higher or lower RPS goals consistent with the high demand or low demand case.[26]
- Staff assumed that new out-of-state renewable builds would be influenced by higher and lower energy demands in California. In the high demand, generic out-of-state renewable projects used in the mid demand case were assumed to expand primarily in regions with RPS targets to reflect regional acceptance of renewable development.
- For the low demand case, staff assumed generic out-of-state renewables lower than the mid demand case. Staff assumed either renewables with a higher relative capital cost, according to the CPUC RPS Calculator, are built or the scale was reduced to reflect the lower demand for the generation.

Renewable Resource Profiles

Renewable generators are not economically dispatched by production cost simulations and therefore require users to input generation profiles. Thermal resources, such as biomass and geothermal are assumed to generate according to a fixed pattern with simulated outages. Solar and wind, however, require pre-defined shapes that represent hourly output levels which vary based on historic weather observations. The simulation software used these shapes to represent the generation profiles for variable renewable generators.

In addition to variations in hourly and seasonal availability, the output of wind and solar projects can vary significantly in different geographic regions because of differences in weather patterns. Staff updated wind and solar hourly generation profiles for the *2015 IEPR* simulation runs to reflect the recent surge in solar generation and continuing growth in the wind industry. In addition, technology preferences and development strategies continue to evolve in the wind and solar industries, which affect generation profiles. For example, many existing wind generators are repowering older turbines with larger and more efficient turbines and relocating individual turbines to minimize bird and bat mortality.

By the end of 2014, solar photovoltaic development had increased to more than 4,500 megawatts (nameplate MWac) of interconnected generation in California, with the expectation that another 1,000 nameplate MWac will become operational in 2015. This magnitude of capacity additions will impact the dispatch of natural gas generators. It is also highly correlated to the region of the state in which the PV is located due to the natural variability of sunlight. Staff found that capacity factors for these PV resources could range from 20 percent to 30 percent, depending on solar resource, technology configuration, location, and local climate conditions.

In addition, PV development has evolved to maximize generation over more hours of the day using tracking systems and modified inverter loading ratios. Staff expects these

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[26] Higher and lower energy demands, relative to the mid demand case, directly affect the RPS targets in each case.

development strategies to continue. New solar thermal projects now operating, each with a particular operating profile, can vary based on facility-specific factors such as the thermal medium, solar-collecting technology, and use of fossil fuel. In addition, new solar thermal projects under development include the use of thermal storage, significantly altering the generation profile and shifting generation by up to six hours. No new solar thermal power plants with storage are expected to be operating in California before the end of the forecast period.

The California ISO collects and maintains five-minute operational data for most of the operating wind and solar projects in California. However, since the facility-specific data are confidential, staff gathered the data by region using a capacity-weighted average to protect its confidentiality. This approach is appropriate for modeling solar and wind generation by region because the regional climate and the technology deployment in the region are intrinsic factors. For example, wind resources have very different profiles based on the geographic region.

For out-of-state projects, staff opted to use wind and solar profiles developed for the WECC TEPPC 2024 common case. Staff made adjustments to ensure these renewable profiles correlated with the synthetic hourly load profiles used in staff's PLEXOS dataset.[27] The TEPPC 2024 common case profile for solar thermal with 6-hour storage was also used to model in-state and out-of-state planned solar thermal projects. TEPPC used a National Renewable Energy Laboratory model to determine approximate shapes based on weather patterns, wind and solar resource, and geographic factors. Energy Commission staff used production levels to infer the output levels.

Table 9 shows WECC renewables to achieve policy goals, and **Table 10** shows California specific goals for all three cases.

Table 9: WECC Renewables to Achieve Policy Goals (TWh)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
States - No RPS	17.5	18.0	18.5	19.0	19.5	20.0	20.5	21.0	21.5	21.9	22.4
AZ*	4.1	4.6	5.1	5.7	6.2	6.7	7.3	7.8	8.3	8.9	9.4
CO*	9.4	9.6	9.9	10.1	10.4	10.7	10.9	11.2	11.5	11.7	12.0
MT	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1
NM	1.5	1.7	1.9	2.1	2.3	2.5	2.6	2.8	3.0	3.2	3.4
NV	6.9	7.1	7.3	7.5	7.7	7.8	8.0	8.2	8.4	8.6	8.8
OR	5.7	6.4	7.2	7.9	8.6	9.4	10.1	10.9	11.6	12.3	13.1
TX*	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5
UT	1.2	1.7	2.3	2.8	3.3	3.9	4.4	5.0	5.5	6.0	6.6
WA	9.1	9.6	10.1	10.5	11.0	11.4	11.9	12.4	12.8	13.3	13.7
Total	56.3	59.8	63.2	66.7	70.2	73.7	77.1	80.6	84.1	87.5	91.0

27 TEPPC 2024 Common Case used the year 2005 hourly load profiles, while Energy Commission staff created a synthetic load shape based on hourly load profiles for 2002 - 2007.

Source: California Energy Commission, Supply Analysis Office. Renewables goals in the WECC TEPPC 2024 Common Case Version 1.5 used to develop a linear trajectory for 2026.[28]

Table 10: Generation to Meet California RPS Goals and Existing Renewables (TWh)

	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Low-RPS	62.3	66.5	67.9	73.9	76.8	74.9	73.3	71.5	69.5	67.5	66.0
Mid-RPS	63.4	68.2	70.2	77.1	81.3	80.7	80.4	80.0	79.6	79.2	78.8
High-RPS	63.7	68.9	71.5	79.5	85.3	85.8	86.7	87.4	88.1	88.9	89.6

Source: California Energy Commission, Supply Analysis Office. Existing renewable resources as of 12/31/2015.

California Renewable Curtailment

In recent months there has been much discussion and analysis focused on the issue of renewable curtailment or over-generation in California. A review of the most recent data provided by the California ISO on this topic reveal 12 days over the past 17 months with manual renewable curtailment. Since April 27, 2014, no instances of supply/demand type of manual curtailments have been reported, only manual renewable curtailments due to transmission outages or transmission congestion.

In simulation modeling, renewable curtailment can be measured by the amounts of *dump energy* or ancillary service violations.[29] Dump energy in the simulation is due to a lack of transmission or transmission constraints, as well as constraints imposed on generation within a given node. In a recent analysis by the California ISO using PLEXOS, a local generation constraint was included to account for a NERC standard.[30] This constraint contributed to instances of renewable curtailment or dump energy as reported in simulation results.[31] In addition to this generation constraint a transmission constraint was imposed to limit the amount of power California can export in each hour of the year, referred to as the *no net exports* constraint. Specifically, the modeling convention for this constraint is that California cannot export more energy than is imported across all interties in all hours of the year. California ISO is currently reviewing other methods to impose this NERC standard and historical exports into production cost modeling. New methods to model these constraints will be presented by California ISO in their TPP process to stakeholders during the last quarter of 2016.

Energy Commission staff is gathering data to further analyze the issue of renewable curtailments and how they should be incorporated into production cost modeling. Given

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[28] See https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Default.aspx.

[29] Violations are downward reserve and load following shortfalls. These are not requirements specified by current tariffs; however, they are constraints that can be defined for simulation modeling of a future year.

[30] NERC BAL-003-1.

[31] See *http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6624 see page 94.*

the shift toward an energy imbalance market and the possibility of more regional coordination, staff did not include this California specific transmission constraint in model runs. Staff did include a local minimum generation constraint in simulations to account for the NERC standard.[32] Included is a constraint in each hour of the year; 25% of the load in California must be met by generation located in California. However, this constraint did not result in any instances of dump energy or renewable curtailment.

California Thermal Generation Resources

California's fleet of natural gas-fired power plants totals about 48,000 MW of capacity. These power plants include combined cycle, aging, peaker, and cogeneration units. Over the 14-year period since 2001, California's gas-fired generation, excluding cogeneration, has seen thermal efficiency improvements of 23 percent.[33] If the cogeneration category is included in this comparison, the efficiency gains over the past 14 years reduced slightly to 18 percent due to the inclusion of the fuel use for useful thermal output (steam). The increase in efficiency is largely due to an increase in generation from combined cycle power plants built since 2000 and reduced reliance on generation from aging power plants. The existing fleet will undergo significant changes in response to the State Water Resources Control Board policy for once-through-cooling (OTC).

California OTC Retirements

In October, 2010, the State Water Resources Control Board (the Water Board) adopted its OTC Policy to address ongoing marine impacts from the use of coastal and estuarine waters for power plant cooling in the state. The OTC Policy is a technology-based standard that will address the adverse effects associated with these cooling water withdrawals without disrupting the critical needs of the state's electricity system. The OTC Policy applies to 19 existing power plants, including two nuclear plants, at which the intake flow rate must be reduced to the level attained by a closed-cycle wet cooling system.[34] Of those, 16 power plants totaling about 17,500 MW are in the California ISO balancing area, and 3 are in the LADWP balancing area.

To meet the OTC policy generators are retiring and/or repowering power plants over the next several years. The SWRCB's OTC policy included many grid reliability recommendations made by the California ISO and joint implementation proposals by the Energy Commission, CPUC, and California ISO. In July 2011, LADWP obtained the SWRCB consent to delay compliance for its three units until 2029. In return, LADWP agreed to exceed the ocean water best available control technology embodied in the OTC policy by eliminating use of ocean water for its repowered facilities. Staff assumed

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[32] NERC Bal-003-1.

[33] "Thermal Efficiency of Gas-Fired Generation in California: 2015 Update", California Energy Commission, 2016, CEC 200-2016-002. Available at: http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-200-2016-002

[34] San Onofre Nuclear Generating Station was unexpectedly retire in 2012. Diablo Canyon Nuclear Power Plant is still subject to the OTC Policy.

that all demand cases would include the specific retirement/repowering dates for each power plant that are consistent with the OTC policy, as outlined in **Table 11.**

Table 11: OTC Implementation Schedules for All *IEPR* Common Cases

Facility & Units	NQC	SWRCB Compliance Date	IEPR Common Case Assumption
Humboldt Bay 1, 2	135	Dec. 31, 2010	Retired Sept. 30, 2010
Potrero 3	206	Oct. 1, 2011	Retired Feb. 28, 2011
South Bay	296	Dec. 31, 2011	Retired Dec. 31, 2010
Haynes 5,6	535	Dec. 31, 2013	Repowered as Air Cooled June 1, 2013
El Segundo 3	335	Dec. 31, 2015	Repowered as Air Cooled July 27, 2013
El Segundo 4	335	Dec. 31, 2015	Retire on Dec. 31, 2015
Morro Bay 3, 4	650	Dec. 31, 2015	Retired Feb. 5, 2014
Scattergood 3	450	Dec. 31, 2015	Repowered as 309 MW Air Cooled Jan 1 2016
Encina 1,2,3,4,5	946	Dec. 31, 2017	Retire on Dec. 31, 2017
Contra Costa 6, 7	674	Dec. 31, 2017	Retired April 30, 2013[35]
Pittsburg 5,6,7	1,307	Dec. 31, 2017	Retire on Dec. 31, 2017[36]
Moss Landing 1,2	1,020	Dec. 31, 2017	NQC de-rated by 15% Dec. 31,2020[37]
Moss Landing 6,7	1,510	Dec. 31, 2017	Retire Dec. 31, 2020[38]
Huntington Beach 1,2	452	Dec. 31, 2020	Retire Dec 31, 2020[39]
Huntington Beach 3,4	452	Dec. 31, 2020	Retired Nov. 1, 2012
Redondo 5,7	354	Dec. 31, 2020	Retire Dec 31, 2020
Redondo 6,8	989	Dec. 31, 2020	Retire Dec 31, 2020
Alamitos 1,2	350	Dec. 31, 2020	Retire Dec 31, 2020
Alamitos 3,4	668	Dec. 31, 2020	Retire Dec 31, 2020
Alamitos 5,6	993	Dec. 31, 2020	Retire Dec 31, 2020
Mandalay 1,2	430	Dec. 31, 2020	Retire Dec 31, 2020
Ormond Beach 1,2	1,516	Dec. 31, 2020	Retire Dec 31, 2020
San Onofre 2,3	2,246	Dec. 31, 2022	Retired Jan. 31, 2011
Scattergood 1,2	367	Dec. 31, 2024	Repower With 2x100 MW NGCT Dec. 31,2015

35 Although NRG retired Contra Costa 6-7, the Marsh Landing facility was constructed beside it.
36 Unit 7 (682 MW) cannot operate independently of Units 5-6.
37 Staff assumed units 1 and 2 will continue operations with a compliance parasitic load of about 15 percent of net qualifying capacity (NQC). See Dynegy/SWRCB Settlement Agreement, http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/docs/energy_comp/settlement_dynegy_2014.pdf .
38 Ibid.
39 AES Huntington Beach, letter to SWRCB, November 8, 2013.

Facility & Units	NQC	SWRCB Compliance Date	IEPR Common Case Assumption
Diablo Canyon 1,2	2,240	Dec. 31, 2024	Assumed Operational Through Forecast period[40]
Haynes 1,2	444	Dec. 31, 2026	Assumed Operational Through Forecast Period
Harbor 1, 2, 5	229	Dec. 31, 2029	Assumed Operational Through Forecast Period
Haynes 8 – 10	575	Dec. 31, 2029	Assumed Operational Through Forecast Period

Source: California Energy Commission, Supply Analysis Office

Other California Generation Retirements

For retirement of in-state non-OTC gas-fired power plants staff assumed they would retire consistent with the direction from the Assigned Commissioner Ruling in the 2014 LTPP.[41] All three demand cases would include capacity retirements in 2015 of: 48 MW of biomass; 18 MW of wind; 170 MW of coal; and 785 MW of natural gas. Staff assumed that between 2016 and 2026 an additional 84 MW of coal and 2,384 MW of gas fired resources are expected to retire.

California Thermal Additions

Staff assumed that all three demand cases would include 620 MW of natural gas resources under-construction and expected to be operational by the end of 2015. Between 2016 and 2026 cumulative additions for all cases included 1,026 MW of new gas-fired combined cycles. New generic onsite and grid-connected CHP, consistent with the Governor's CHP goals, are added in the low demand and mid demand cases starting in 2019, while the high demand case includes no new CHP beyond that embedded in the revised *2015 CED Revised*.

For the low demand case, only new generic CHP is added to this case. There is no need for additional thermal resources beyond the cumulative 1,646 MW common to all cases. Between 2019 and 2026, new generic grid-connected CHP capacity of 2,023 MW and new generic onsite CHP capacity of 2,629 MW is included in the low demand case.

In addition to the 1,646 MW additions common to all cases, the mid demand case includes 991 MW of new generic NGCCs and 800 MW new generic CTs by 2026. Between 2019 and 2026, new generic grid-connected CHP capacity of 1,491 MW and new generic onsite CHP capacity of 1,339 MW is included in the mid demand case.

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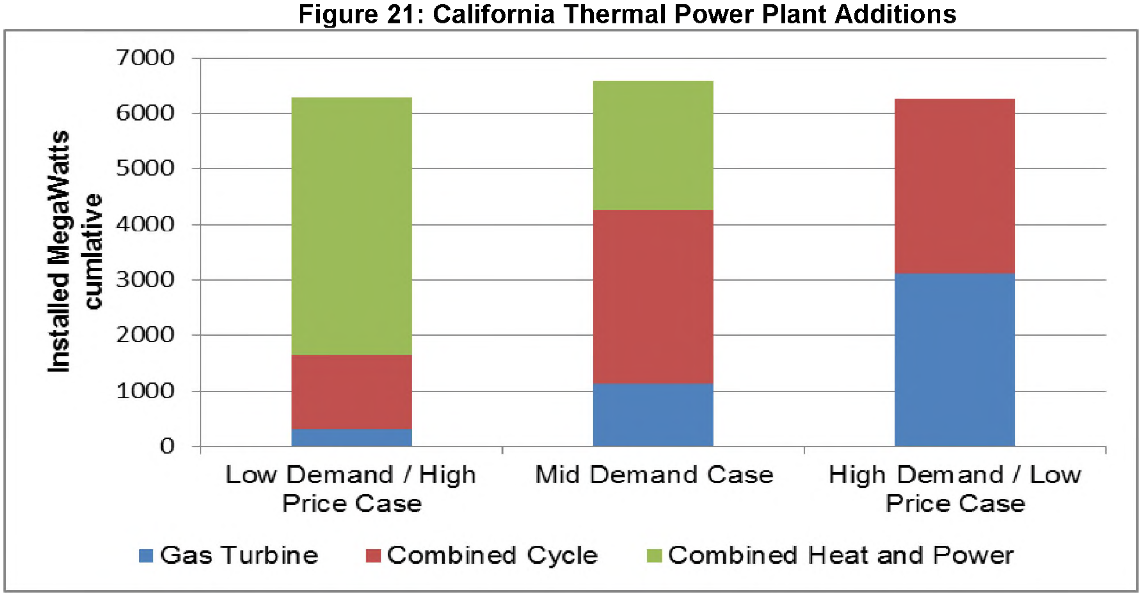
40 A study of the OTC requirements and mitigation options for Diablo Canyon was overseen by the SWRCB's Review Committee for Nuclear Fueled Power Plants last year and the SWRCB has yet to make a decision.

[41] Assigned Commissioner Ruling, May 14, 2014. Available at: http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=304572.

The high demand case also includes 1,646 MW common to all cases but also includes 1,824 MW and 2,800 MW, of NGCCs and NGCT, respectively by 2026. No new CHP is added in this case beyond the amounts included in the 2015 CED.

Figure 21 shows assumed thermal power plant capacity additions in California between 2015 and 2026. All three common cases include identical thermal capacity additions in 2015. The high demand/low price case includes more NGCC and GT capacity than the mid demand and the low demand/high price cases; however, the low demand/high price case adds more CHP capacity than the mid demand and high demand/low price cases. This is due to the higher energy prices in the low demand/high price case, which offer incentives for large energy users to develop more CHP for their needs, as well as create opportunities for sales to the grid.

Figure 21: California Thermal Power Plant Additions



Source: California Energy Commission, Supply Analysis Office

WECC Thermal Generation Resources

The WECC region is made up of a diverse mix of generation resources that vary by geographic area, totaling about 275,400 MW of nameplate capacity in 2014, including California generating resources.[42] Coal and natural gas and hydro comprise over 80 percent of the installed and net generation. The following addresses thermal power plants for rest of WECC, excluding California.

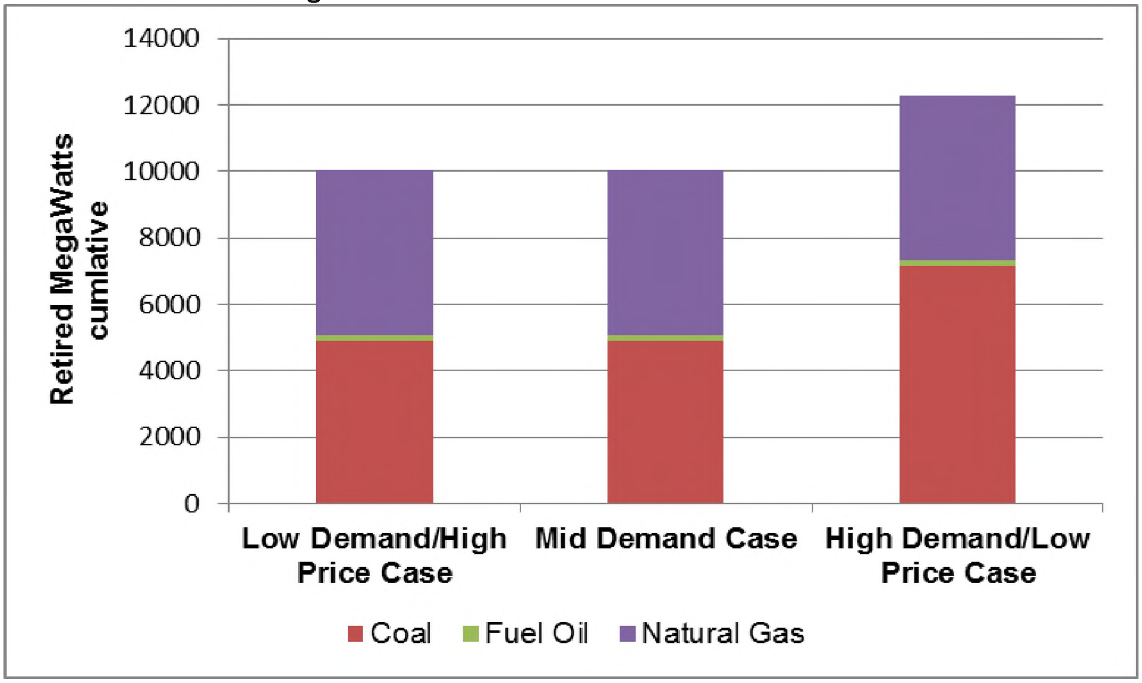
WECC Thermal Retirements

All three common cases include about 10,000 MW of retirements in the WECC area, excluding California retirements (discussed in the previous section), throughout the forecast period. This consists of about 5,080 MW coal and fuel oil capacity and 4,934 MW of natural gas capacity. The high demand/low price includes an additional 2,250

[42] *2015 State of the Interconnection*, Western Electricity Coordinating Council, 2015. Available at: https://www.wecc.biz/Reliability/2015%20SOTI%20Final.pdf.

MW of coal retirements in 2023. **Figure 22** shows thermal plant capacity retirements for the remainder of the WECC territory.

Figure 22: Thermal Power Plant Retirements for WECC

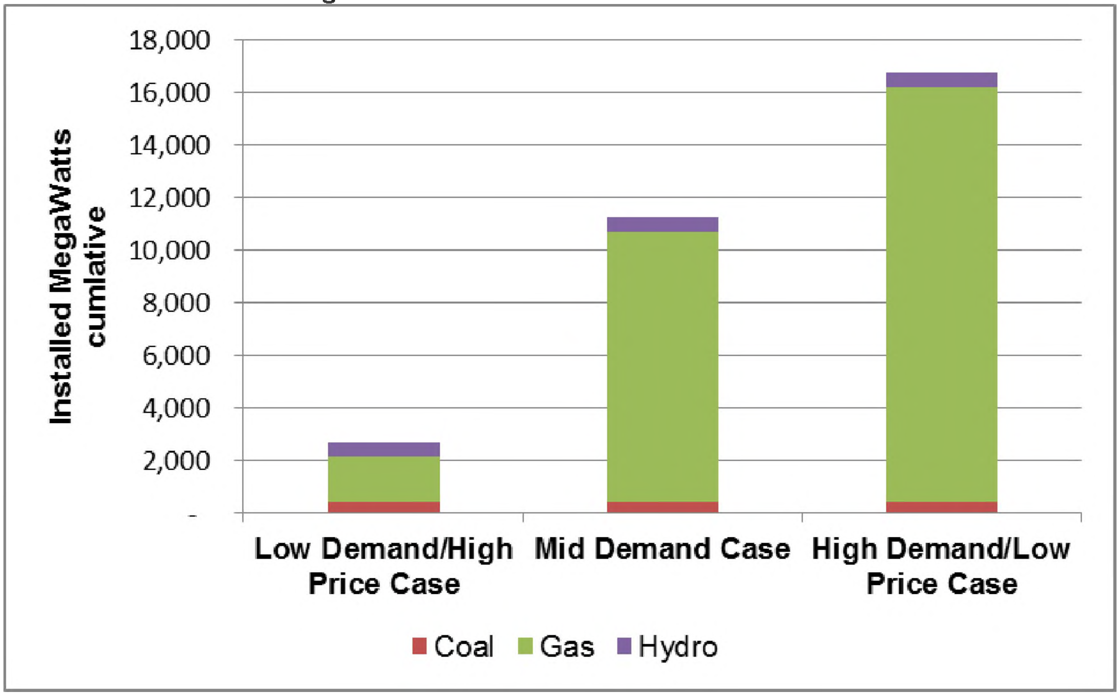


Source: California Energy Commission, Supply Analysis Office

WECC Thermal Additions

The TEPPC 2024 common case includes new natural gas capacity additions of 8,263 MW, and 428 MW of new coal capacity by 2024. For the low demand case, by 2026 an additional 1,284 MW of natural gas capacity is added, while the mid demand case includes 3,606 MW of natural gas capacity. The high demand case includes more than double the total gas capacity added to the mid demand case. In the high demand case, 9,128 MW of natural gas capacity are included by 2026. **Figure 23** shows thermal power plant capacity additions for the rest of WECC.

Figure 23: Thermal Power Plant Additions for WECC



Source: California Energy Commission, Supply Analysis Office

CO_2e, Natural Gas and Other Price Assumptions

CO2e Price Projections

California committed to take action to address the threat through the adoption of the California Global Warming Solutions Act of 2006 (Assembly Bill 32 or AB 32; Nuñez, Chapter 488, Statutes of 2006), which is codified at California Health and Safety Code sections 38500 *et seq.* AB 32 requires California to reduce GHG emissions to 1990 levels by 2020, to maintain and continue GHG emissions reductions beyond 2020, and to develop a comprehensive strategy to reduce dependence on fossil fuels, to stimulate investment in clean and efficient technologies, and to improve air quality and public health. The Cap-and-Trade Program is a key element of California's GHG reduction strategy. The Regulation establishes a declining limit on major sources of GHG emissions, and it creates a powerful economic incentive for major investment in cleaner, more efficient technologies. The California Cap-and-Trade Program is administered by the ARB. Quarterly Auctions for CO_2e allowances are run by the ARB but no source is available for future price projections of CO_2e allowance prices which are a key input to simulation models. Most market parties rely on private companies to forecast future CO_2e allowance prices. These are rarely published in a public forum. Therefore, Energy Commission staff used the following method to develop ranges of CO_2e price projections that can be used in publically vetted forums and analysis. It is important to emphasize that these projections, though used in modeling, are just projections, not guarantees of any particular market performance.

The starting price for 2015 was calculated based on the Vintage Settlement Price for all 2015 auctions (February, May, August and November) weighted by the quantity (metric ton) sold.[43] Future CO_2e prices were assumed to increase annually by five percent plus the Consumer Price Index for all urban consumers. The CO_2e price projections used in the modeling are shown in **Table 12**. The Stress and Reference Cases use the same carbon prices through the forecast period.

Table 12: CO_2e Price Projections (nominal dollars per metric ton)

Year	California	Rest of WECC
2020	27.15	18.10
2021	29.22	19.48
2022	31.45	20.97
2023	33.86	22.57
2024	36.46	24.31
2025	39.26	26.18
2026	42.30	28.20
2027	45.59	30.39
2028	49.15	32.77
2029	53.01	35.34
2030	57.19	38.13

Source: California Energy Commission, Supply Analysis Office

Natural Gas Burner Tip Prices

California Energy Commission staff develops multiple plausible estimates of the natural gas market including burner-tip prices used in the production cost simulation.[44] See Appendix E3 for the list of prices used in these simulations

Other Prices

For the 2015 IEPR, Energy Commission staff updated the delivered coal fuel price forecast used by the model. Delivered coal prices refer to the amount that a power plant pays for coal to generate electricity. These prices include the commodity price, or mine-mouth price, and the cost to transport coal from the mine to the plant. This is comparable to natural gas burner-tip prices. The data source used as the basis for this

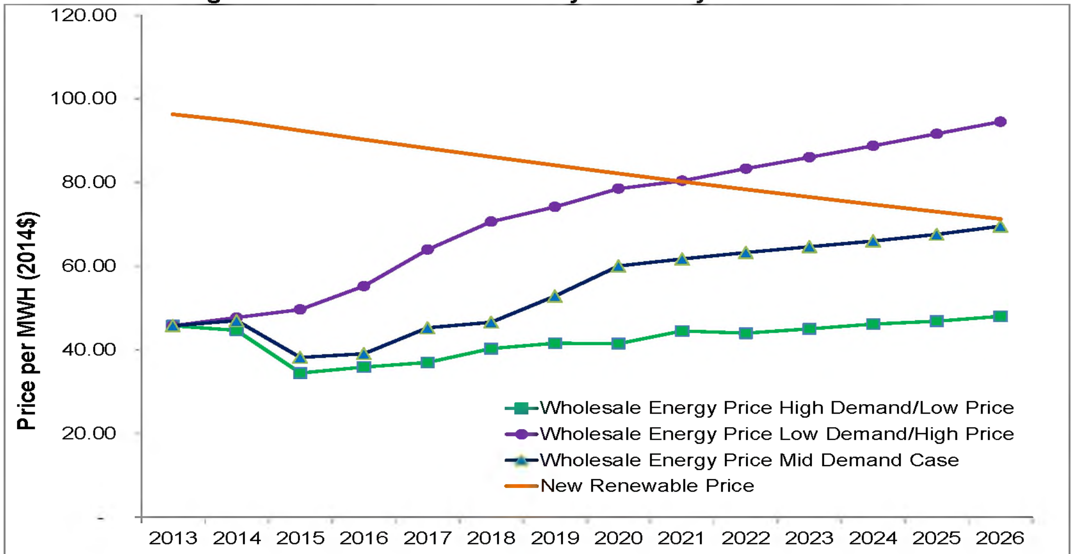
[43] http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN208931_20160125T073329_2015_IEPR_Final_GHG_Cost_Projection.xlsx

[44] Brathwaite, Leon, Anthony Dixon, Jorge Gonzales, Robert Kennedy, Chris Marxen, Peter Puglia, Angela Tanghetti. 2015. 2015 Natural Gas Outlook Draft Staff Report. California Energy Commission. CEC-200-2015-007-SD. Available online at http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN206501_20151103T100153_Draft_Staff_Report_2015_Natural_Gas_Outlook.pdf

update was the US EIA's 2015 Annual Energy Outlook. See Appendix E4 for the delivered coal prices used for this analysis.[45]

Wholesale electricity prices are used in estimating electricity rates as part of the demand forecast (see Table 5). The wholesale electricity prices are shown in **Figure 31** below.

Figure 31: Wholesale Electricity Prices by Demand Case



Wholesale energy price calculated using an average heat rate of 8,000 Btu/KWH.
Renewable price is weighted average of levelized cost curves from 2015 Cost of Generation Report: 43% solar, 40% wind, 11% geothermal, 7% biomass.

Source: California Energy Commission, Supply Analysis Office

Residential Model Description and Building and Appliance Standards Incorporation

Model Description and Inputs

The Energy Commission residential forecasting model is an end-use model based on historic utility residential survey data, building simulations, conditional demand analysis, and economic and demographic data and projections.

The model focuses on:

- 3 housing types - single family, multi-family and mobile home.
- 5 housing "vintages" to capture building standards impacts.
- 3 fuel types - electricity, natural gas and other
- 24 residential end-uses

[45] http://www.eia.gov/forecasts/aeo/ Tables 55 through 55.22

Residential End-Uses

Water heating	Lighting
Backup for Solar Water Heater	Color Television
Pump for Solar Water Heater	Swimming Pool Pump
Dishwasher	Swimming Pool Heater
Incremental water heating dishwasher	Backup for Solar Pool Heater
Clothes Washer	Hot Tub Pump
Incremental water heating clothes washer	Hot Tub Heater
Clothes Dryer	Space Heater
Miscellaneous	Furnace Fan
Cooking Range	Central Air Conditioning
Refrigerator	Room Air Conditioning
Freezer	Evaporative Air Conditioner

The model uses demographic data to predict the number of households. It also uses survey information to determine, for each end use, the average number of appliances found in a typical household. Based on current trends, the model projects the addition and replacement of appliances over time. As new appliances are added, they are assumed to meet applicable efficiency standards in place at the time. The model tracks the number of appliances added under each new vintage of standards and then estimates, on average, how much energy each appliance is likely to use, which is called the unit of energy consumption (UEC).

Space conditioning UECs are based on older building simulation analysis and non-space conditioning appliance UECs are based on conditional demand analysis from existing Residential Appliance Saturation Study surveys and consultant reports along with engineering estimates.

Modeling of Residential Energy Efficiency in Demand Forecast

UECs are the main measure of consumption in the residential model. UECs are benchmarked to their pre-1978 values, as this was the period prior to the introduction of standards. Heating and cooling properties of the building shell are indexed to pre-1975 levels, which is prior to the first building standards requirements.

When new standards are introduced, the index for each impacted end-use is lowered in accordance with the expected percentage savings of the standard on that particular end-use. Likewise, impacts from new building standards are modeled using a similar percentage reduction in heating and cooling loads for homes constructed in and after the year the standard was introduced. Savings for heating and cooling are a combination of both building shell improvements and appliance improvements.

This modeling framework allows staff to estimate the cumulative impact of standards relative to the pre-standards baseline. This is done by running the model with and without adjustments to the UEC indexes and then calculating savings as the difference in energy demand output between the model runs.

The table below identifies standards that are specifically incorporated in the residential model. More recent standards have been post-processed.

Building and Appliance Standards Incorporated in the Residential Forecast Model

1975 HCD Building Standards	1976-82 Title 20 Appliance Standards
1978 Title 24 Residential Building Standards	1988 Federal Appliance Standards
1983 Title 24 Residential Building Standards	1990 Federal Appliance Standards
1991 Title 24 Residential Building Standards	1992 Federal Appliance Standards
2005 Title 24 Residential Building Standards	2002 Refrigerator Standards 2009 Television Standards 2010 Lighting Standards

Post-processing

For newer appliance standards (since 2010), post-processing adjustments have been made to estimate end-use consumption based on analysis provided by Codes and Standards Enhancement (CASE) studies of the Energy Commission's Efficiency Division. Post-processing adjustments have also been made to account for building standards since 2001. This is because of the complexity of fitting the newer building standards (which allow for a more flexible set of measures to gain compliance and focus on previous noncompliance) into the current model structure. Post-processing is also needed to account for many of the residential building standard requirements for both new and existing homes that cannot yet be explicitly included in the residential demand forecasting model. Water heating distribution efficiency, efficient windows, cool roofs, and HVAC duct sealing are examples of measures in the building standards that are not explicitly accounted for in the model.

Commercial Model Description and Building Standards Incorporation

The Commercial Forecast Model (CFM) is an energy intensity model that calculates energy use per square foot based on building type. Like the residential model, the commercial model is an end-use model that is primarily informed by the following input data: Energy Use Intensity (EUI, energy per square foot), floor space, and fuel saturations. Floor space data is figured by building type and year, saturations, and EUIs are figured by building type, end-use, fuel type, and vintage. The CFM projects energy use for 12 building types, 10 end-uses and three fuel types as shown in the table below.

Commercial Forecast Model Inputs

Building Types	End-use	Fuel Type
Small Office	Heating	Electricity
Restaurant	Cooling	Natural Gas
Retail	Ventilation	Oil
Food/Grocery	Cooking	
Warehouse	Water Heating	
Refrigerated Warehouse	Refrigeration	
School	Indoor Lighting	
College/University	Outdoor Lighting	
Hospital	Office Equipment	
Hotel/Motel	Miscellaneous Equipment	
Miscellaneous		
Large Office		

The EUI is the main energy indicator used in the commercial model. Input data EUIs are defined for the base year of 1975 and nine distinct building vintages thereafter. 1975 was selected as the base year since it was prior to the application of building standards and coincided with an onsite survey study conducted during that year from which the original EUI values were estimated.

The EUIs for the base year are defined in kBtu/SqFt, all the subsequent vintages are defined as percentages of the base-year EUIs. At the present time, the EUI input data includes nine building vintages (1975, 79, 84, 92, 98, 01, 05, 08, and 2013) and sixteen climate zones[46] across California. The impacts of the 2016 Standards will be incorporated in the next forecast. These building vintages correspond to cycles of standards, and are characterized by the efficiency levels in effect in each cycle. The relative EUIs reflect changes to the base year values as the result of the impacts of the proposed changes to the standards.

[46] This will be expanded to 20 forecast zones for future forecasts.

Energy Savings Adjustments

The energy savings from the standards are published in a document called the *Impact Analysis Report*. This report is an integral part of the standards, and it is presented to the public at large as part of the adoption process for each cycle of standards. Commonly, programs are sponsored by IOUs and the savings associated with Building and Appliances standards are determined under the direction of the Energy Commission's Efficiency Division, Buildings Standards Office. The standards affect both newly constructed buildings as well as alterations to existing buildings, both of which are covered in the *Impact Analysis Reports* and include savings estimates for both building type. Treatment of energy efficiency savings in the Energy Commission's demand forecast is similar for new construction and existing buildings, and the explanations provided in this section applies to both.

Once a set of standards is officially adopted, the Demand Analysis Office obtains and considers the estimated energy savings for incorporation in the forecast. The estimated savings must be assigned to building types and end-uses accounted for in the forecast and are converted to a percentage format to be usable in the CFM. The following section describes assignment and conversion process.

Assigning Savings to Building Type and End-use

The estimated savings must first be assigned to the building type, end-use, and fuel type accounted for in the CFM. In cases where the *Impact Analysis Report* is not explicit, savings are assigned to building type(s) and end-use(s) based on the measures' characteristics. For example, the 2013 standards specify requirements for parking garage exhaust fans. However, the standards do not specify the building types and/or the end-uses that would be affected by this measure. Therefore, after careful examination of the characteristics of the measure, the savings are assigned to building types that are most likely to have parking garages. In this particular case, the savings were assigned to miscellaneous end-use of the following building types: large offices, universities, hospitals, and hotels.

Format Conversion

As mentioned in the previous section, the CFM's input data EUIs are defined as a percentage of the base-year values. As such, to incorporate programs and standards savings into the forecast, the savings need to be converted to a percentile format. The following example illustrates a sample calculation for the conversion:

- Existing cooling EUI for building type i and vintage j = 85.6% of the base-year
- Reported impacts of proposed changes to the Standards = 75 GWh
- Cooling energy from the latest forecast for building type i and vintage j = 3,260 GWh
- % Savings = 75 / 3,260 = 2.3%
- Multiplier = 1 – 0.023 = 0.977

- New cooling EUI = Existing cooling EUI * Multiplier = 85.6 * .977 = 83.63%

Treatment of Commercial Building and Equipment Decay

The commercial forecast model keeps track of the retirement and replacement of buildings and equipment by vintage using decay functions.

Building Decay

The CFM keeps track of all floor space vintages that make up the entire floor space stock in any forecast year. For example, if the forecast year is 2010, the model keeps track of all floor space added from 1964 to the year 2010 adjusted for decay. Although commercial buildings vary widely in their decay characteristics, a simplified logistic function is assumed to be a reasonable representation of the decay.

Equipment Decay

Equipment decay adds an additional time dimension and complication to the vintaging of floor space. Consider the forecasting year 2010 in the above example, a certain percentage of equipment installed in each of the older building vintages decays and must be replaced. This dating of equipment within building vintages allows for a calculation to estimate the effect of equipment decay. For simplicity, we assume that all decayed equipment is replaced instantaneously and is of the same capacity and fuel type as the original equipment. The equipment decay is estimated using a modified Weibull distribution function.

Price Treatment in Existing Floor Space

Energy prices have a direct impact on the level of energy consumption. The consumption tends to increase when energy prices fall and decrease when energy prices rise. In addition, higher energy prices result in installation of more energy efficient equipment and conservation measures. The CFM is designed to include the effect of energy prices in the forecast, which will be discussed in more detail in the post-processing section.
The impact of energy prices on existing floor space is defined as utilization rate, which is fuel, end-use, building type, and vintage specific. All utilization rates are initially set to one in the base year (1975). The utilization rate in subsequent years is assumed to vary depending on the levels of equipment efficiency, fuel price, and short run utilization (price) elasticities.