Exhibit CAC# 45-10

CAC Manitoba: Book of Documents
NFAT Review

Tab	Document
1	Ontario Power Authority, *Demand Forecast*, 2013 LTEP: Module 1 Slide 1-7, 43-45
2	Ontario Power Authority, *Conservation Targets and How They Reduce the Demand Forecast*, 2013 LTEP: Module 2 Slide 1-16
3	California Energy Commission, *California Energy Demand 2014-2024 Final Forecast: Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency* (December 2013) p. 5-8, 35-36, 87-103

TAB 1

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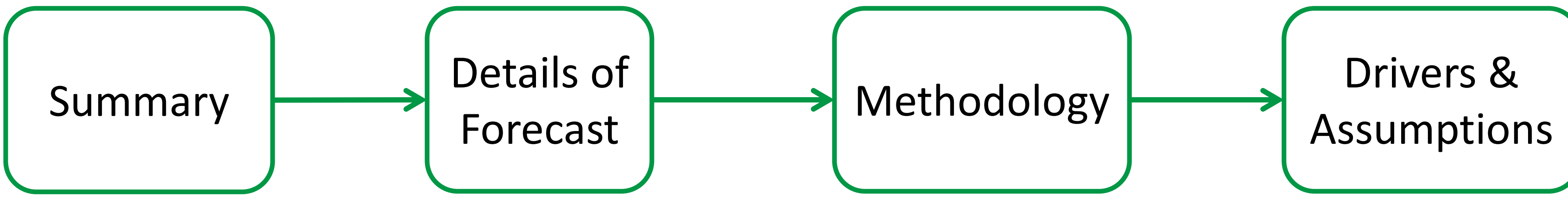
Demand Forecast

2013 LTEP: Module 1

January, 2014

Overview

This module will walk you through the steps for developing the demand forecast. It outlines forecast energy use by sector and end use, and highlights changes that are affecting electricity demand



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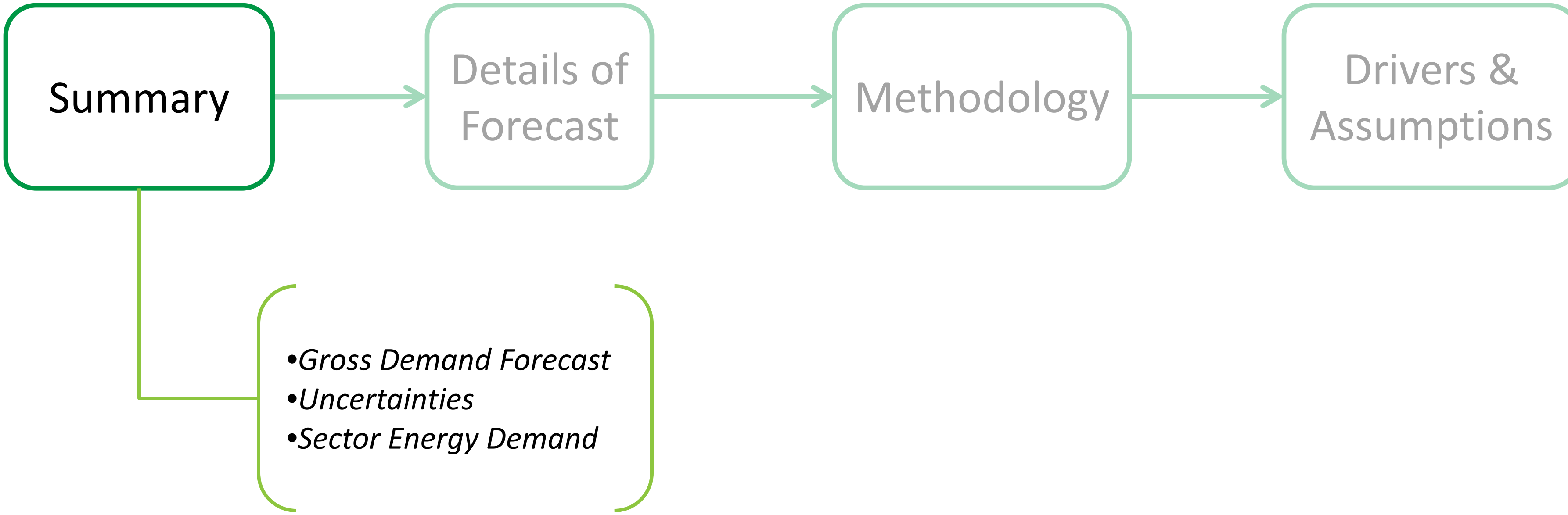
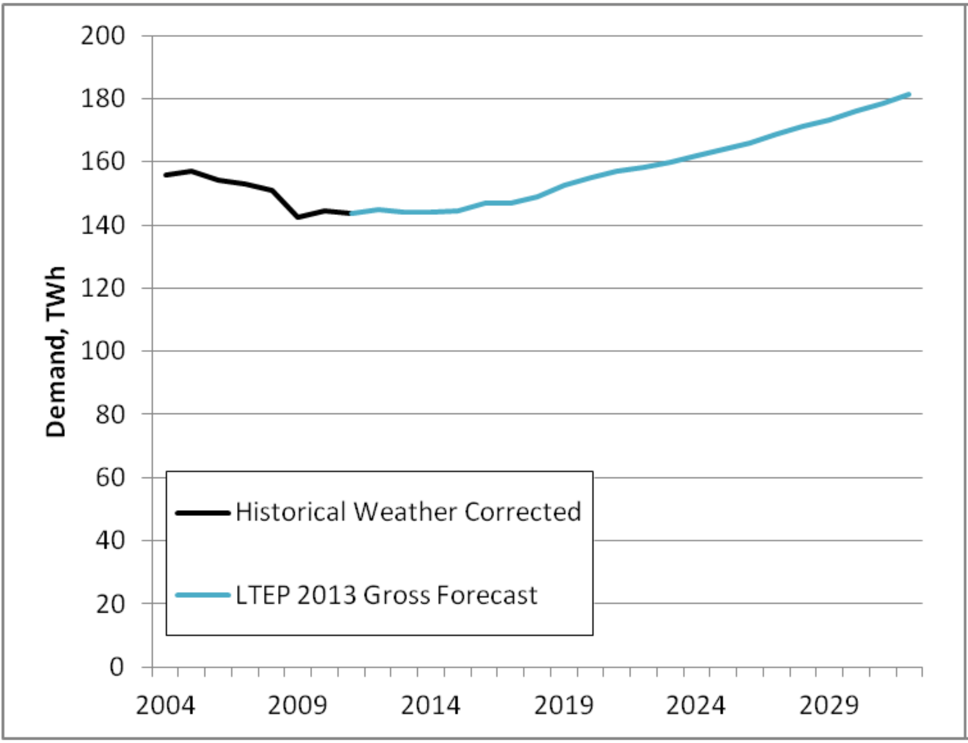
Summary

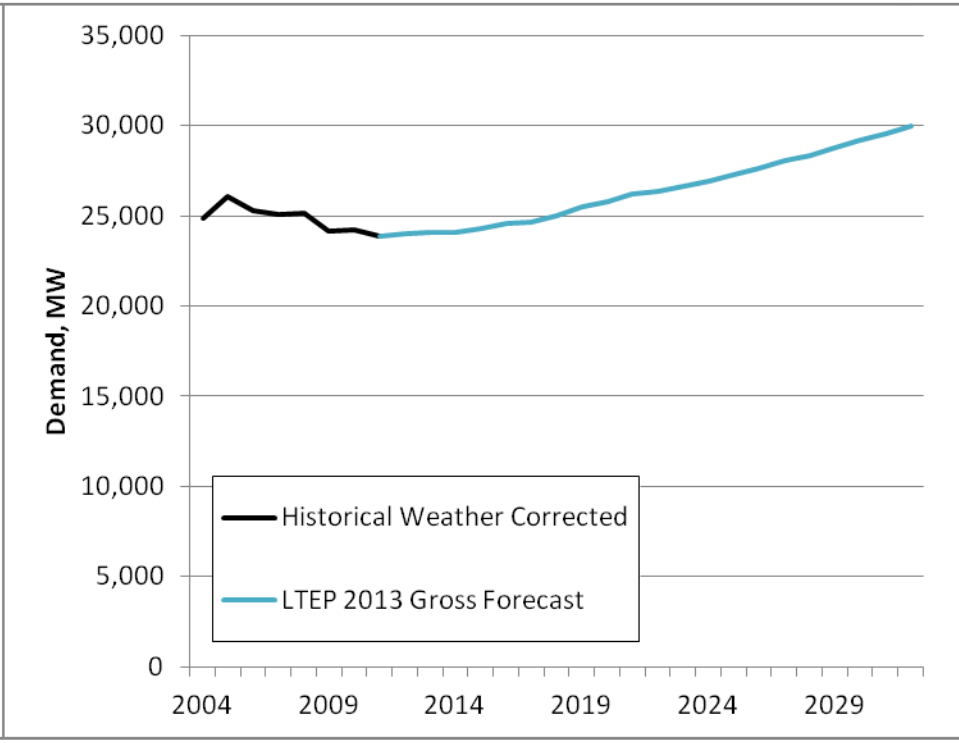

Summary
Details of Forecast
Methodology
Drivers & Assumptions
•Gross Demand Forecast
•Uncertainties
•Sector Energy Demand

2013 LTEP Gross Demand Forecast

- The gross demand forecast presents the expected electricity demand before the impacts of codes and standards, conservation policies and programs are considered
- The demand forecast is developed on an end-use basis to provide insight into how and when customers use electricity, support detailed generation and transmission planning, and provide insight into conservation planning
- The demand forecast has been rebased to 2011, meaning that the gross demand is set equal to the net demand for that year. The success of past conservation efforts have been included in the rebasing and the increments in demand and conservation savings are considered each year beyond 2011
- The demand forecast includes consideration of how customers will change their electricity use in response to changing electricity prices, technological change and changes from market transformation. These give rise to decreased demand that is expected to occur without further market intervention

2013 LTEP Gross Demand Forecast (based in 2011)





- Forecasted electricity values are taken back to the generator level, which accounts for transmission and distribution losses. Historical values are corrected for weather and for embedded generation in the distribution system, which is not visible to the IESO markets but contributes to meeting demand. The embedded generation value for 2011 is 2.4 TWh. This represents known contracted generation. 2011 is used as the base year moving forward.

Data Tables for 2013 LTEP Gross Demand Forecast

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Energy, TWh	143.6	145.0	144.1	143.9	144.6	146.9	146.9	149.1	152.4	155.0	157.1
Peak, MW	23,837	24,028	24,042	24,097	24,275	24,579	24,665	25,024	25,511	25,805	26,174

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy, TWh	158.2	159.7	162.0	163.8	166.0	168.7	171.3	173.5	176.1	178.7	181.3
Peak, MW	26,368	26,607	26,907	27,259	27,596	28,041	28,367	28,766	29,167	29,539	29,944

Forecasted electricity values are taken back to the generator, which accounts for transmission and distribution losses.

The 2011 base year value is weather corrected and includes 2.4 TWh of embedded generation added to IESO measured demand.

Uncertainties

- Several factors that could significantly impact the forecast are:

  Upside uncertainties:
  - lower than expected response to prices
  - resurgence of the industrial sector
  - “new” as yet unidentified uses of electricity
  - commercial data farm/server growth greater than expected
  - adoption of grow lights in agricultural applications

  Downside uncertainties:
  - greater than expected response to higher electricity prices leading to greater efficiency uptake
  - dramatic cost decrease of new efficient technologies, leading to increased uptake by the market
  - movement toward smaller residential dwellings
  - decline of electricity-intensive industries
  - softening of commodity prices, leading to decreased industrial output

Methodology Highlights

- The production of the OPA's gross demand forecast utilizes an estimation of annual electricity demands by the residential, commercial/institutional and industrial sectors. This is done through a detailed accounting of all the current uses of electricity by these sectors as well as how those uses will change over time.
- Two main factors influence the change in demand over time: (1) demographic and economic drivers such as changes in household formation, commercial floor space, industrial output and (2) energy price and the influence price has on the choice of appliance or equipment purchased and installed.
- The OPA utilizes independent economic forecasts to assist in developing the forecast drivers
- Gross electricity demand estimates are developed with the aid of the OPA's End-Use Forecaster Model (EUF) which carries out this analysis at the end-use level. The term "end use" refers to the service provided, such as air-conditioning, motive power, lighting or refrigeration.

Methodology Highlights (cont'd)

- EUF tracks equipment and building stocks over time and simulates technology acquisition in the economy. Equipment stock changes because of new additions as well as by the replacement of retired equipment at the end of its lifespan.
- The choice of which equipment is bought and installed is influenced by the energy costs to operate the equipment as well as the initial capital cost at purchase. Non-financial factors influence choice as well.
- Annual sectoral and gross electricity demands are developed for each of the 10 IESO zones and transformed into gross hourly demand values using end-use level hourly load shapes. A load shape characterizes the variation in the electricity consumption of a given end use as a function of time and recognizes changes throughout the day, weekday and weekend, and across the year. For example, residential air conditioning is consumed primarily in the hot summer months, refrigerators are plugged in 24/7, and some industries have a 2 shift while others have a 3 shift operation.
- The resulting gross forecast is produced at the zonal, sectoral and end-use level, on an hourly basis for the 20 year forecast period.
- An overview of the process is provided in the next slide.

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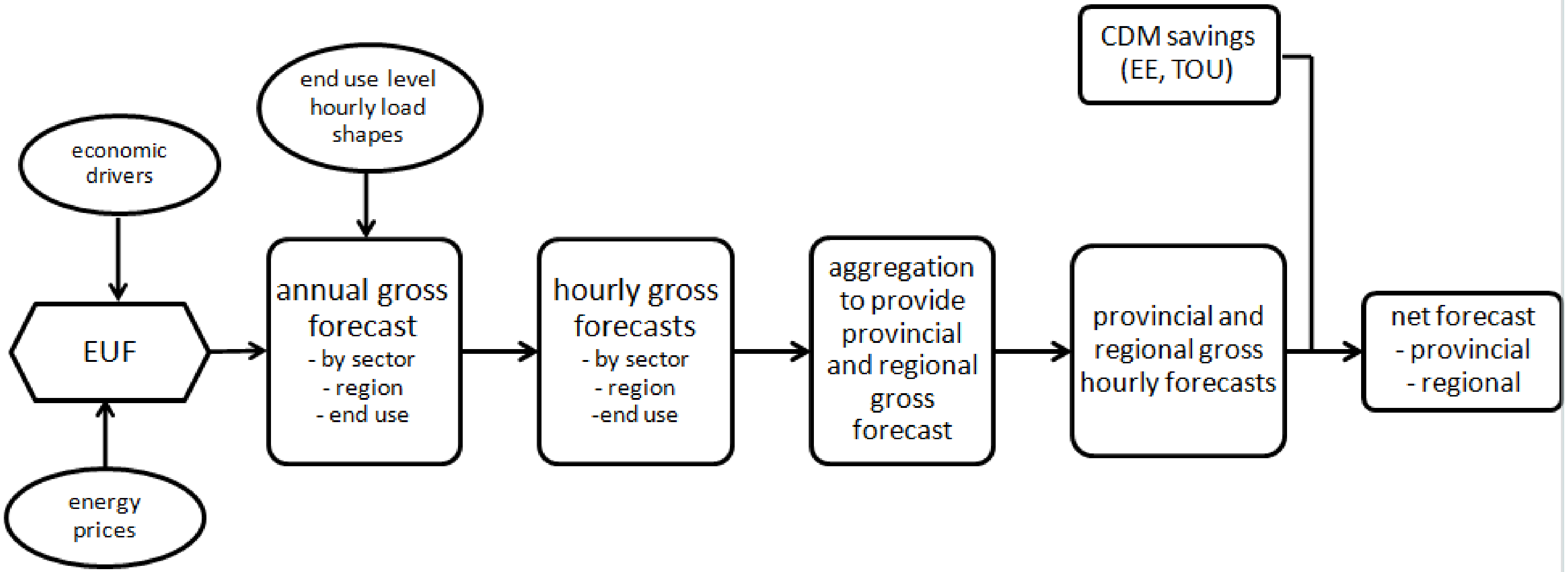
Process For Developing the Demand Forecast



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TAB 2

Conservation Targets and How They Reduce the Demand Forecast

2013 LTEP: Module 2

January 2014

Overview of Module 2

This module will walk you through the steps for integrating conservation into the demand forecast. It provides detail of results achieved to date and forecasts of savings required to meet the target outlined in LTEP. A new framework is being developed for the delivery of conservation that will outline more detail on conservation plans

Energy Efficiency → Impact on Demand Forecast → Demand Response

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Energy Efficiency

Energy Efficiency → Impact on Demand Forecast → Demand Response

- *Targets*
- *Current Capacity*
- *Codes, standards and programs required*

LTEP 2013 Conservation Goals

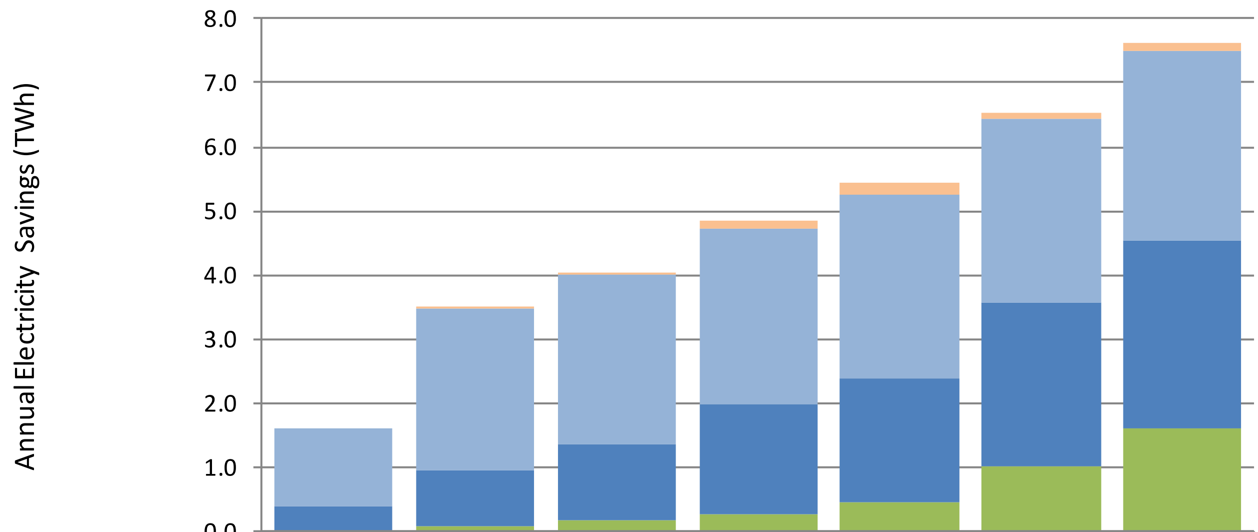
- Longer term conservation target of 30 TWh in 2032 of electricity consumption reduction.
- Electricity consumption reduction will be achieved through a combination of:
  - Codes and standards
  - Energy efficiency programs
- Demand response is to meet 10% of peak demand by 2025, resources include:
  - Existing demand response programs
  - New DR resources to be developed
  - Time-of-use rate
  - Industrial Conservation Initiative
  - Dispatchable customer loads under contract in the market

Basis of Projections for Electricity Conservation

- Conservation target of 30 TWh in 2032 are savings achieved between 2005 and 2032.
- The forecast amounts of electricity reduction in each year are indicative of current assessment of potential. They do not represent targets. The Achievable Potential study is underway and expected to be completed the first quarter of 2014.
- Codes and standards forecasts are developed based on technology and building code improvements.
- The balance of the savings are the subject of planning and future programs.
- To ensure programs are cost effective, a combination of the Total Resource Cost Test, the Program Administrator Cost Test and a hurdle rate will be used to screen program designs.
  - Cost effectiveness tests compare the cost of acquiring savings to the benefits realized by those savings
- Progress will be reported on in the Ontario Energy Report.

Energy Efficiency Achieved to Date

- From 2006 to 2012, codes and standards, OPA conservation programs, and non-OPA programs and activities have contributed a total of 7.6 TWh of savings in 2012.



	2006	2007	2008	2009	2010	2011	2012
Demand Response and Pre-2008 Customer Based Generation	0.0	0.0	0.0	0.1	0.2	0.1	0.1
Other Influenced	1.2	2.5	2.6	2.7	2.9	2.9	3.0
Energy Efficiency Programs	0.4	0.9	1.2	1.7	1.9	2.6	2.9
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6
Total	1.6	3.5	4.0	4.9	5.4	6.5	7.6

Note: Other Influenced is the electricity savings from conservation activities by organizations and programs not funded by the OPA. Examples are federal government programs and gas utilities' programs.

Potential Electricity Savings from Future Codes and Standards

- Analysis of codes and standards savings is based on expected improvement in energy efficiency anticipated through the regulation of building codes and product and appliance standards.
- Codes and standards (C&S) are an effective means to deliver energy efficiency at no ratepayer cost and with broad reach and a high level of certainty when forecasting results.
- Majority of C&S savings will come from commercial and residential sectors. Industrial savings are assumed to be negligible because of the minimal efficiency improvement in motors, the largest end use in this sector.
- Forecast of codes and standards savings provides insight into the level of energy efficiency that can be achieved from regulation and indicates the level of other program effort that will be required to meet or exceed targets.

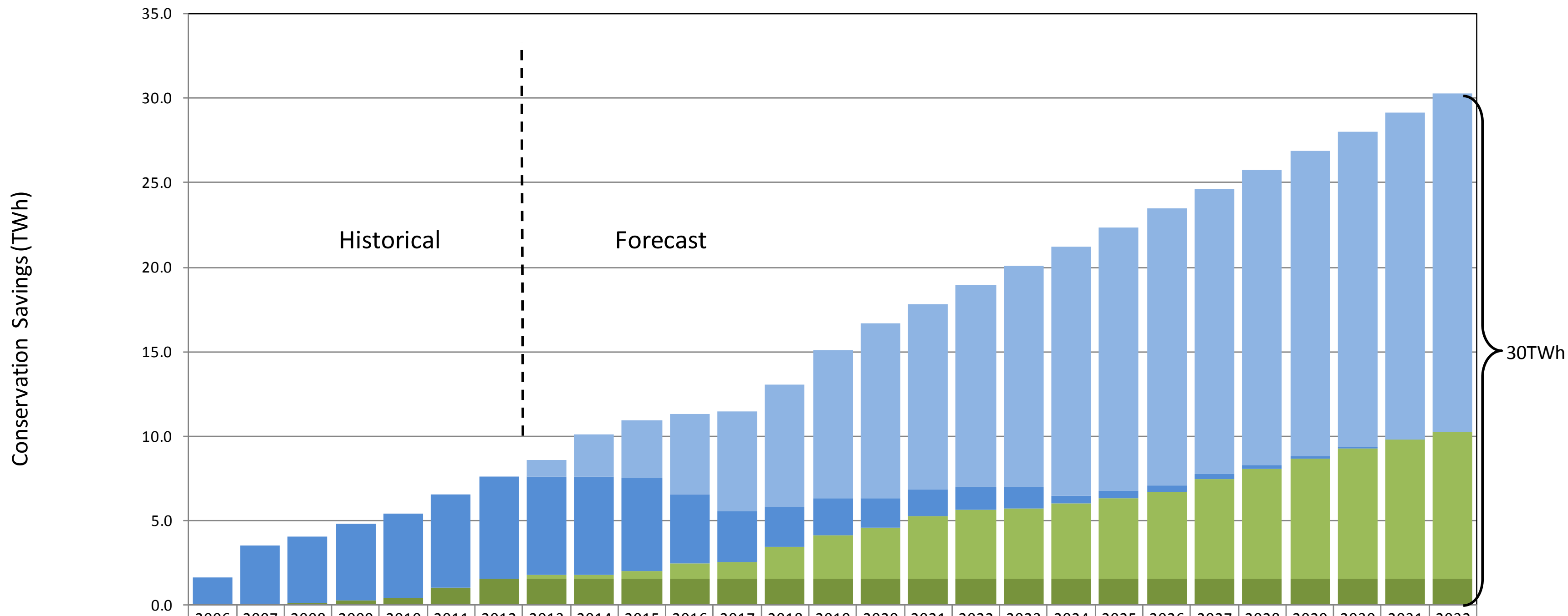
More Details about Future Codes and Standards

- Commercial Codes:
  - The estimate of savings is calculated by comparing the codes forecast case to the reference case.
  - The Ontario Building Code requires new buildings to be built to a certain energy efficiency level.
  - The Ontario Building Code references the ASHRAE 90.1 standard.
  - A series of reduction factors for lighting, ventilation and space cooling was estimated based on ASHRAE long-term reduction target. The codes forecast assumes that building systems are built to achieve this reduction target.
- Residential Standards:
  - The Minimum Energy Performance Standards requires all products sold to comply with a minimum energy efficiency level.
  - When products with lower efficiency are retired, new products are distributed among remaining available efficiency levels.
  - The reference case distributes stock as if regulations were frozen at 2005 levels. The standards forecast case includes distribution of stock across higher efficiency levels. The difference in electricity use between the two is the estimate of savings due to standards.

Energy Efficiency from Future Conservation Programs

- Incentive and information based programs, funded by electricity rates, provide savings that contribute to meeting the LTEP conservation target.
- The saving estimate is informed by past program performance and the most up to date understanding of the key opportunities for energy savings.
- As programs are delivered and new programs developed, greater understanding of the savings opportunities by sector, end use and region will be developed.
- The government, in co-operation with LDCs and energy agencies, is developing a new conservation and demand management framework. The new framework starting in 2015 will lay out the details of conservation savings for the next period.

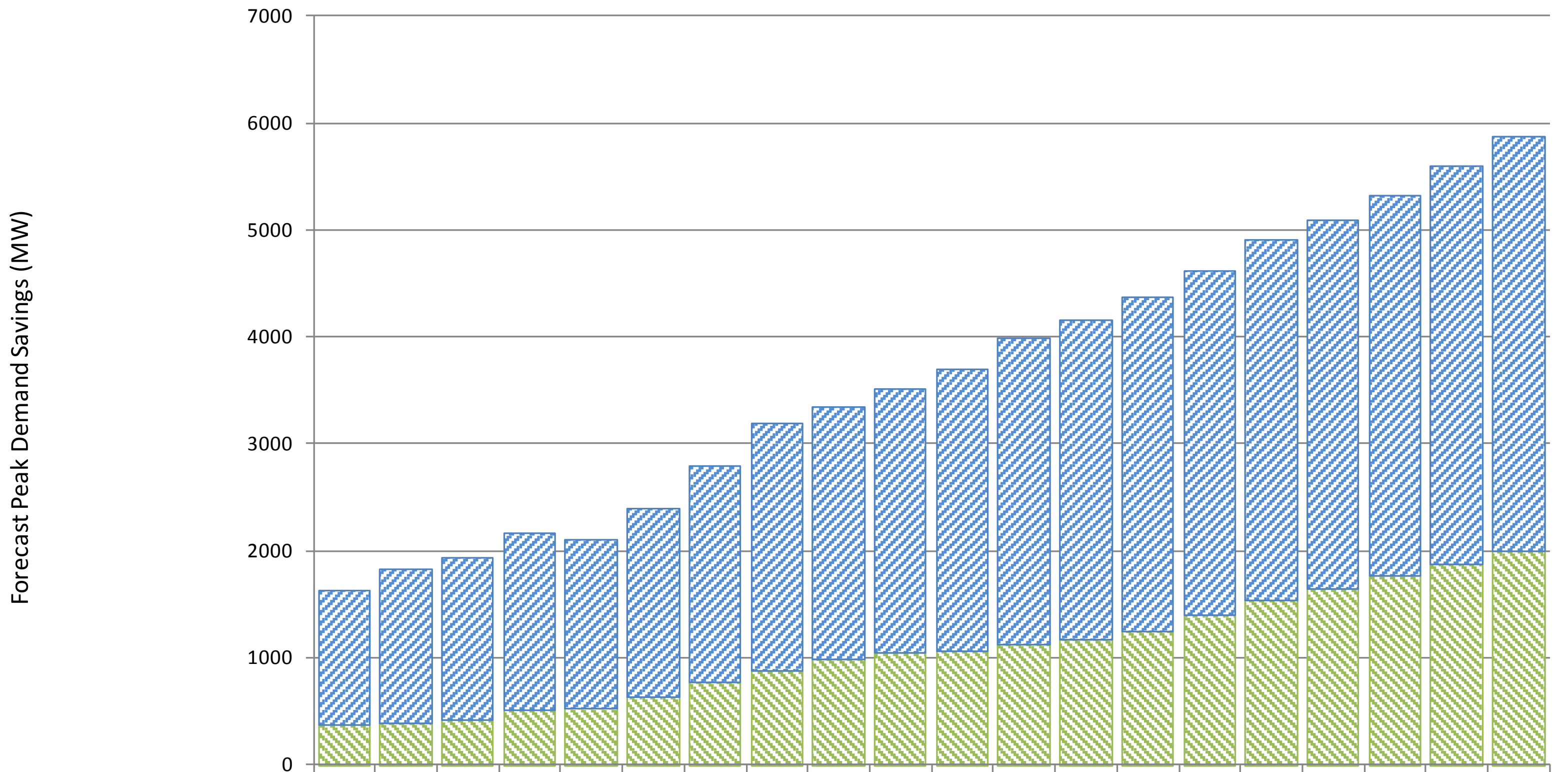
Historical and Target Electricity Consumption Reduction



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Forecasted savings from future programs								1.0	2.5	3.3	4.8	5.9	7.2	8.7	10.4	10.9	12.0	13.1	14.7	15.5	16.4	16.8	17.5	18.0	18.7	19.3	20.0
Historical program persistence (2006-2012)	1.6	3.4	3.9	4.6	5.0	5.5	6.0	5.9	5.8	5.5	4.1	3.0	2.3	2.2	1.8	1.6	1.4	1.3	0.5	0.5	0.4	0.3	0.2	0.1	0.0	0.0	0.0
Codes and Standards (forecasted savings)								0.2	0.2	0.5	0.9	1.0	1.9	2.6	3.0	3.7	4.0	4.1	4.4	4.7	5.1	5.8	6.4	7.1	7.7	8.2	8.6
Codes and Standards (existing savings)	0.0	0.1	0.2	0.3	0.5	1.0	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
LTEP 2013 total energy savings	1.6	3.5	4.0	4.9	5.4	6.5	7.6	8.6	10.1	10.9	11.3	11.4	13.0	15.1	16.7	17.8	19.0	20.1	21.2	22.3	23.5	24.6	25.7	26.9	28.0	29.1	30.2

- Savings with 2005 as the reference year.

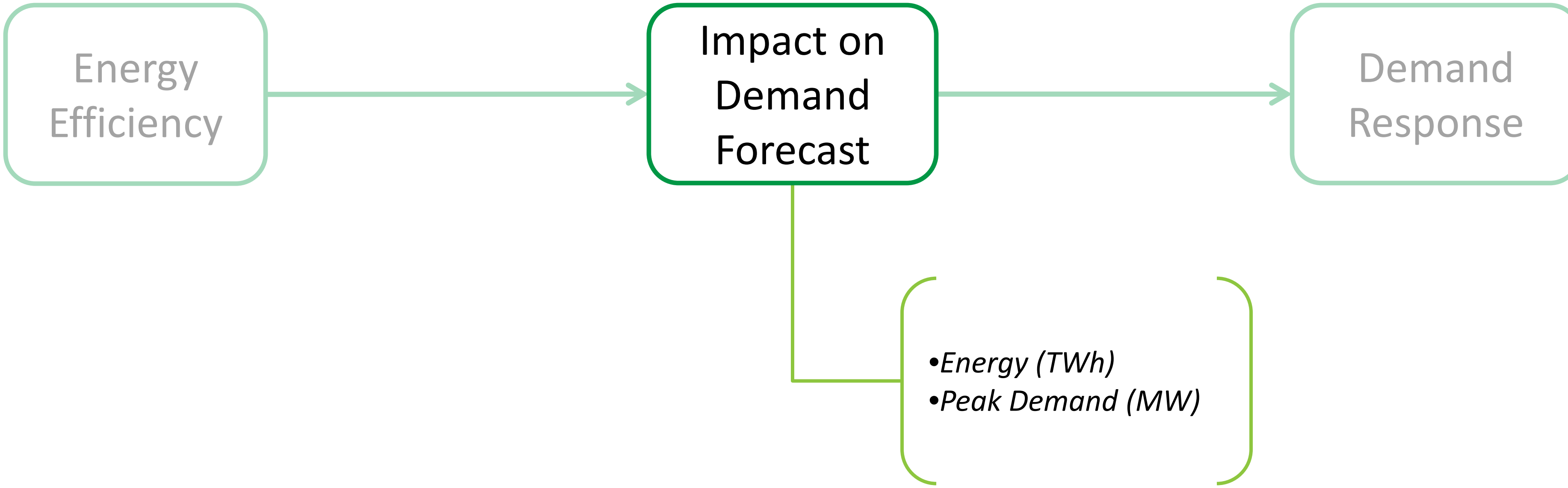
Peak Demand Reductions (in MW) Associated with Electricity Consumption Saving Targets (in MWh)



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
EE (historical and future programs)	1248	1435	1528	1662	1575	1752	2022	2321	2357	2470	2636	2865	2985	3125	3224	3378	3444	3556	3720	3880
Codes and Standards (existing and forecast)	373	386	413	505	525	639	777	876	984	1039	1056	1128	1176	1244	1398	1537	1647	1768	1879	1988
Total	1621	1820	1942	2167	2099	2391	2799	3197	3341	3509	3693	3993	4160	4369	4622	4915	5091	5324	5599	5868

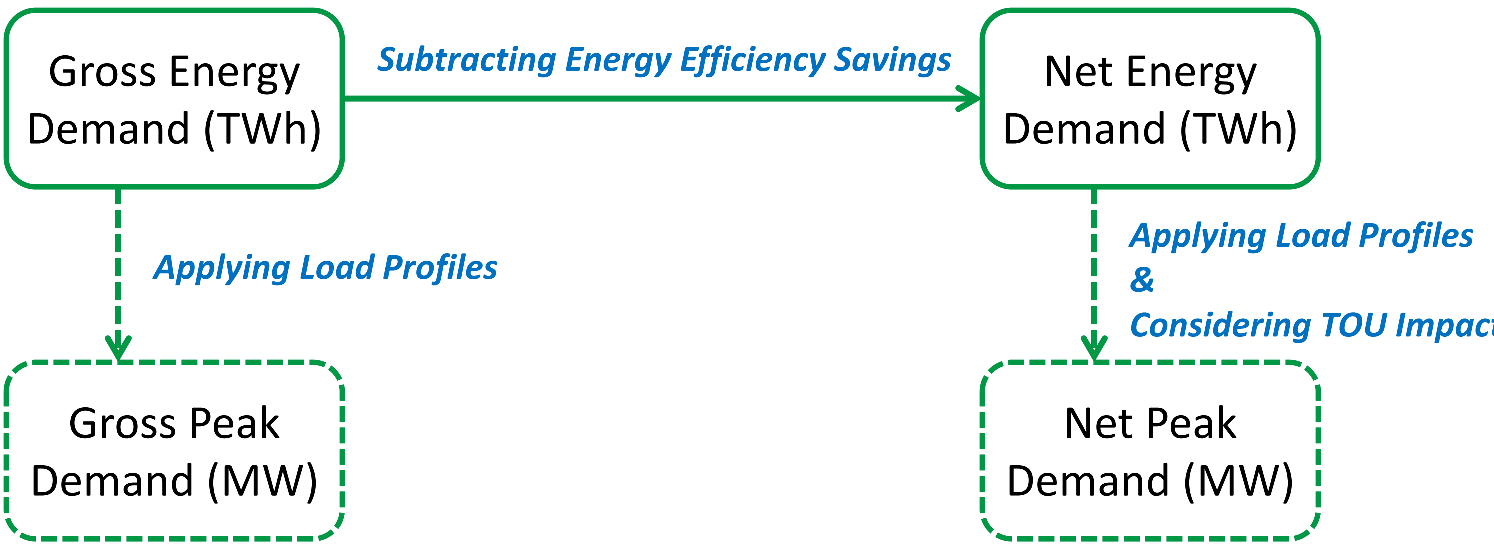
- Forecast peak demand reductions are estimated from gross peak and net peak (see slides 15 & 16)
- Peak demand savings from time-of-use are additional, which is included on the chart on slide 16.
- Dispatchable DR resources are considered separately.

Impact on Demand Forecast



Developing a Net Demand Forecast

- The gross demand forecast (see Module 1) describes the energy and peak demand for electricity before incremental conservation is considered.
- The LTEP 2013 conservation target of 30 TWh will be subtracted from the gross energy demand. The result is the net energy demand.
- The net demand forecast is the amount of electricity demand that will need to be served by generation, transmission and distribution.



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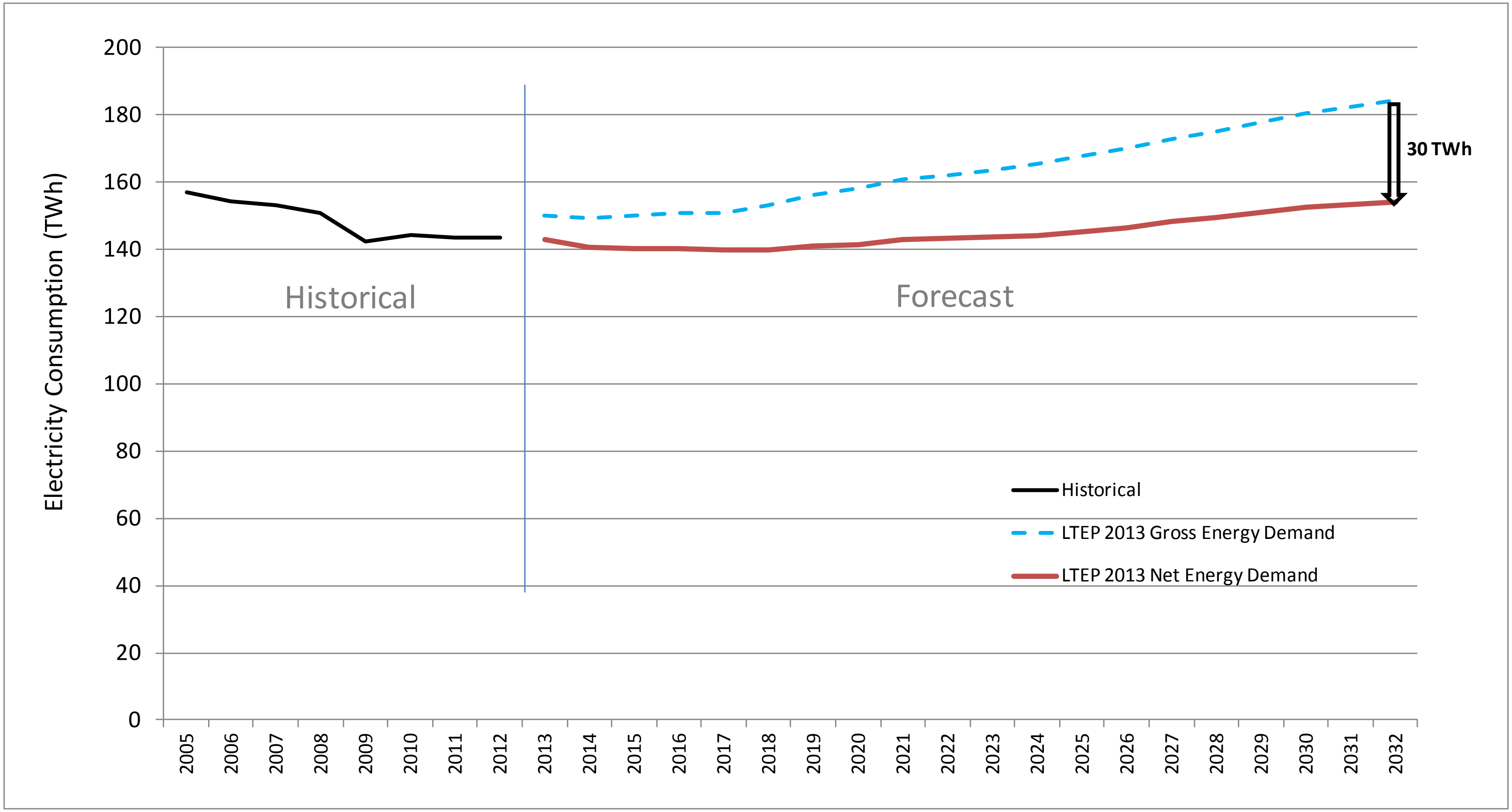
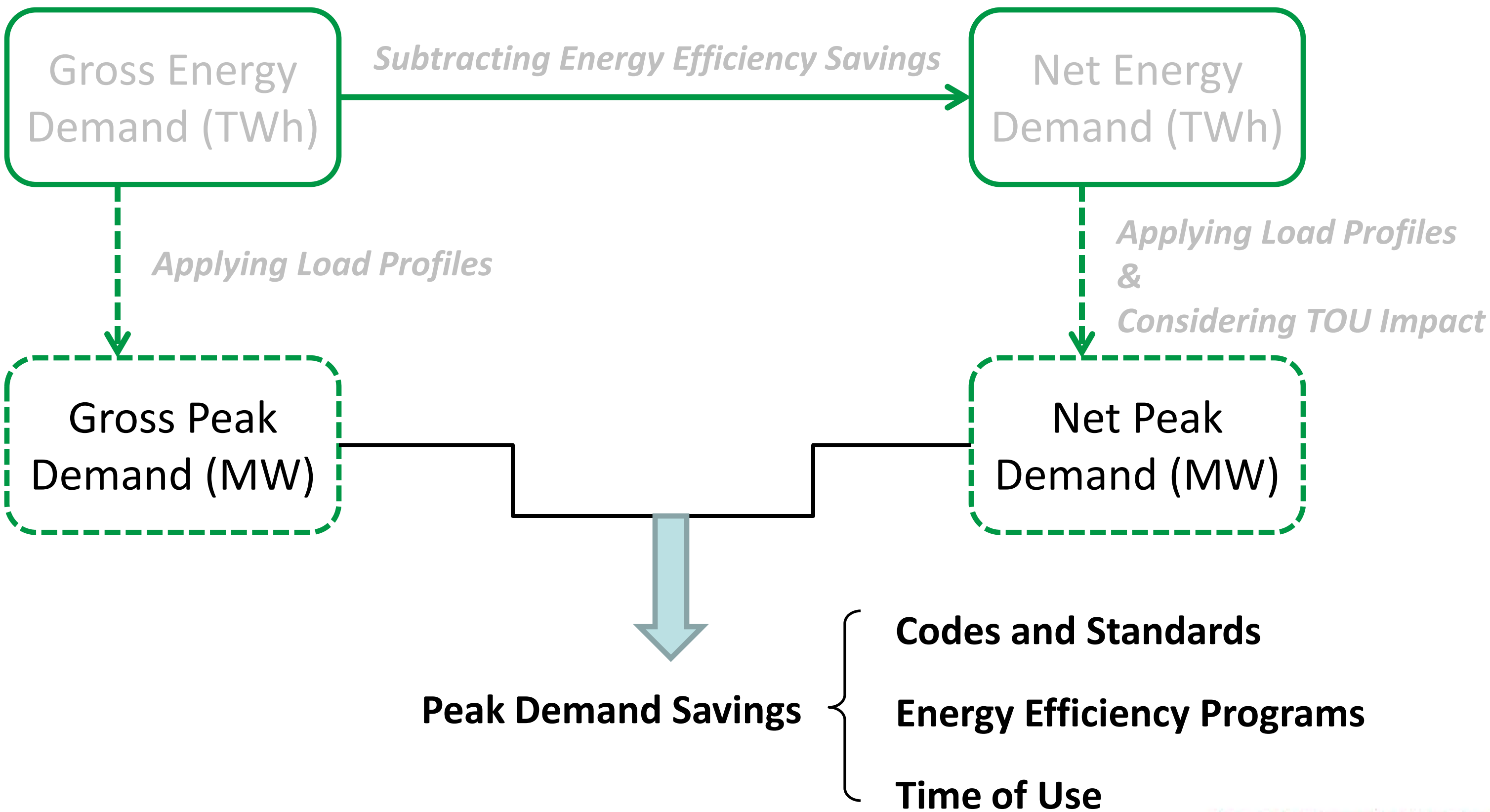
Gross and Net Energy Demand Forecasts

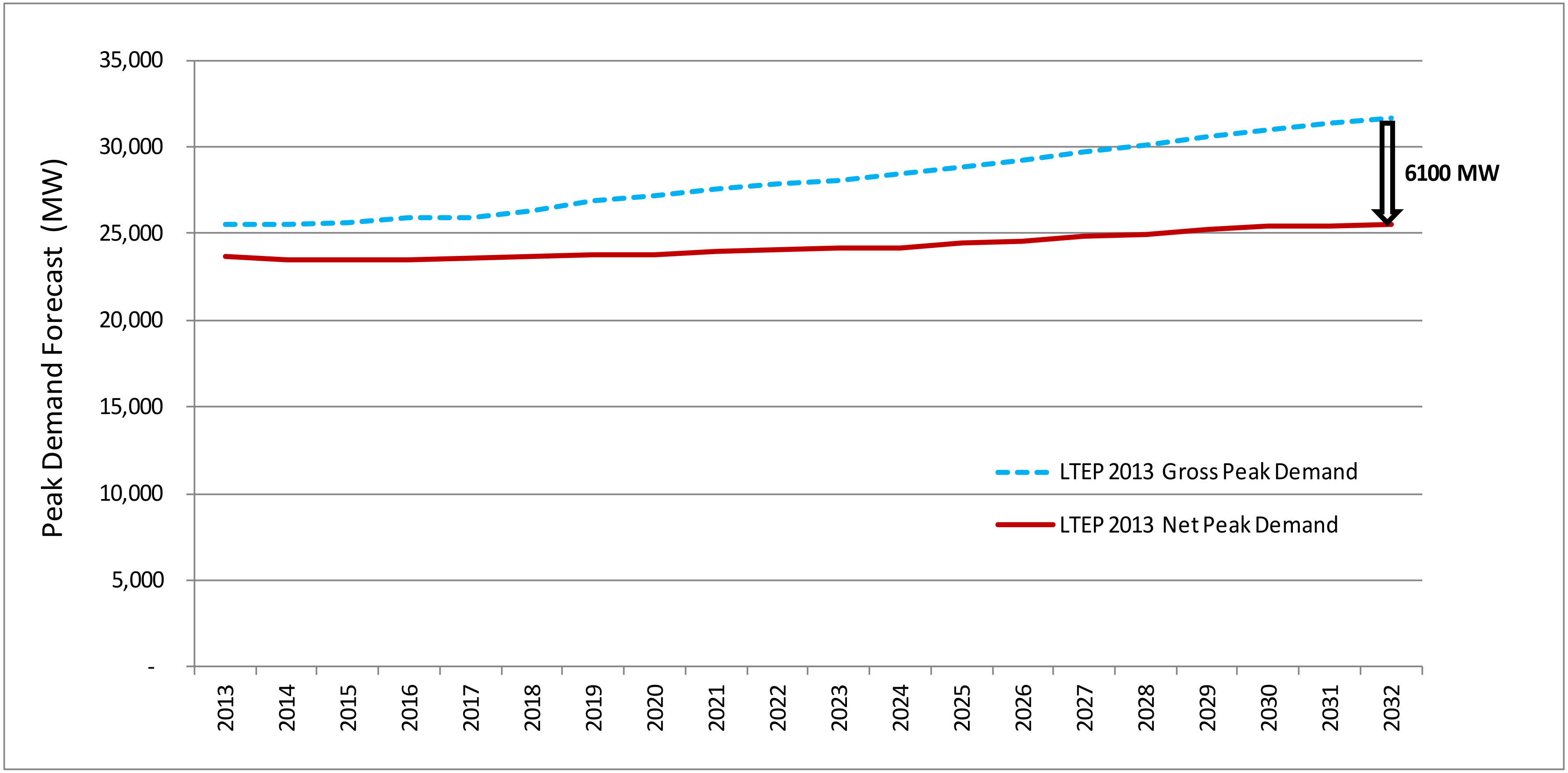


Peak Demand and Peak Demand Savings Estimate

- Gross peak demand is represented by an hourly gross demand forecast.
- Net peak demand is represented by an hourly net demand forecast.
- The difference of the two is the estimated peak demand savings. Demand reduction from DR resources is considered separately.



Gross and Net Peak Demand Forecasts



- 2005 is the reference year.
- Peak demand savings are from C&S, EE programs, and TOU.

TAB 3

California Energy Commission

STAFF FINAL REPORT

CALIFORNIA ENERGY DEMAND 2014–2024 FINAL FORECAST

Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency

CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown Jr., Governor

DECEMBER 2013

CEC-200-2013-004-SF-V1

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Table ES-2: Statewide Baseline End-User Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2011 Mid Case	*CED 2013 Final High Energy Demand*	*CED 2013 Final Mid Energy Demand*	*CED 2013 Final Low Energy Demand*
1990	12,893	12,893	12,893	12,893
2000	13,913	13,913	13,913	13,913
2012	13,123	12,767	12,767	12,767
2015	13,503	12,736	12,687	12,176
2020	13,961	12,816	12,774	12,423
2024	--	12,801	12,806	12,569
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2012	-0.49%	-0.71%	-0.71%	-0.71%
2012-2015	0.96%	-0.08%	-0.21%	-1.57%
2012-2022	0.70%	0.06%	0.04%	-0.19%
2012-2024	--	0.02%	0.03%	-0.13%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013.

Committed Conservation/Efficiency

Energy Commission demand forecasts seek to account for efficiency and conservation that has or is likely to occur. Traditionally, the forecasts have made a distinction between committed and uncommitted, or achievable, efficiency impacts. The baseline forecasts in *CED 2013 Final* continue that distinction, with only committed efficiency included. Committed initiatives include those having final authorization, firm funding, and a program plan. Committed impacts also include price and other market effects not directly related to a specific initiative.

Figure ES-3 shows staff estimates of historical and projected committed savings impacts, which include those from programs, codes and standards, and price and other market effects. Within the demand scenarios, 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.

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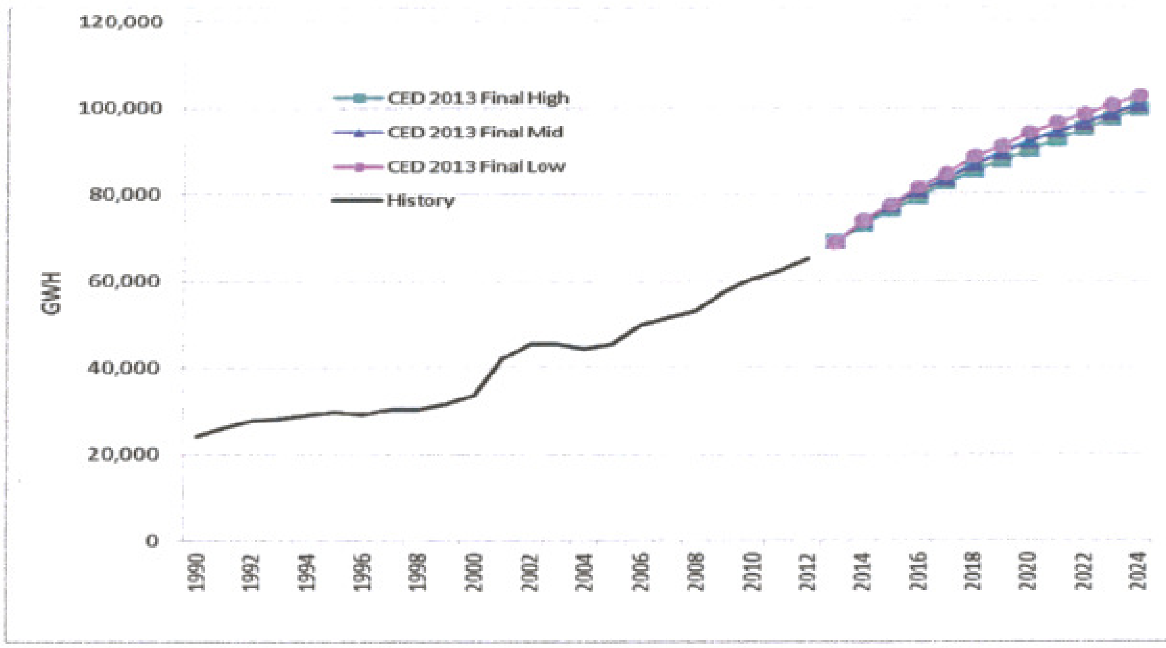
Figure ES-3: Total Statewide Committed Efficiency and Conservation Impacts

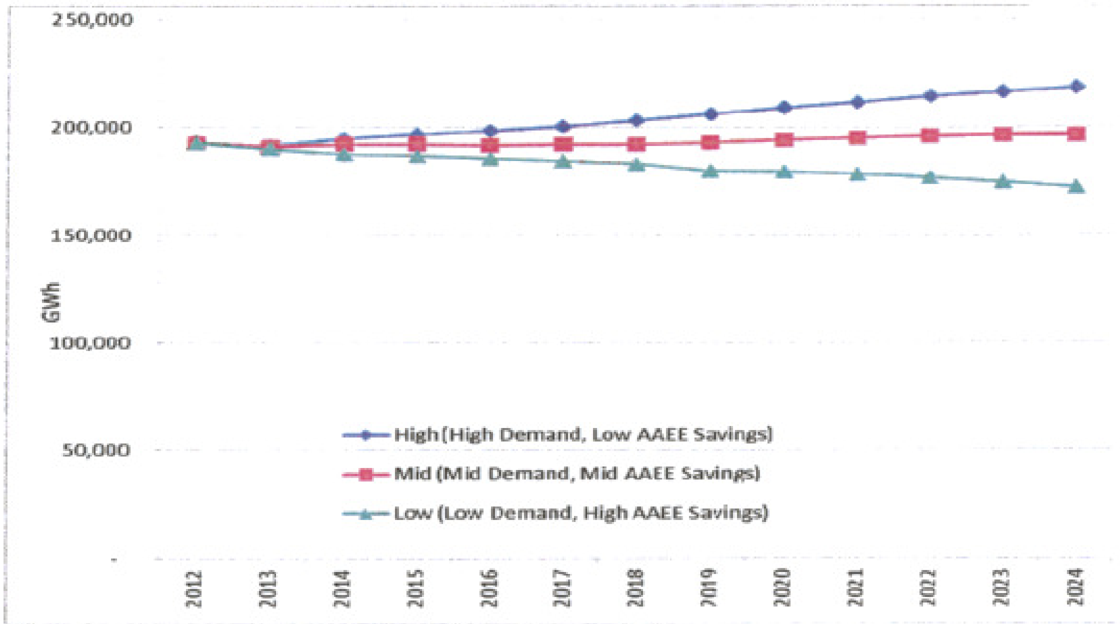


Source: California Energy Commission, Demand Analysis Office, 2013.

Additional Achievable Energy Efficiency

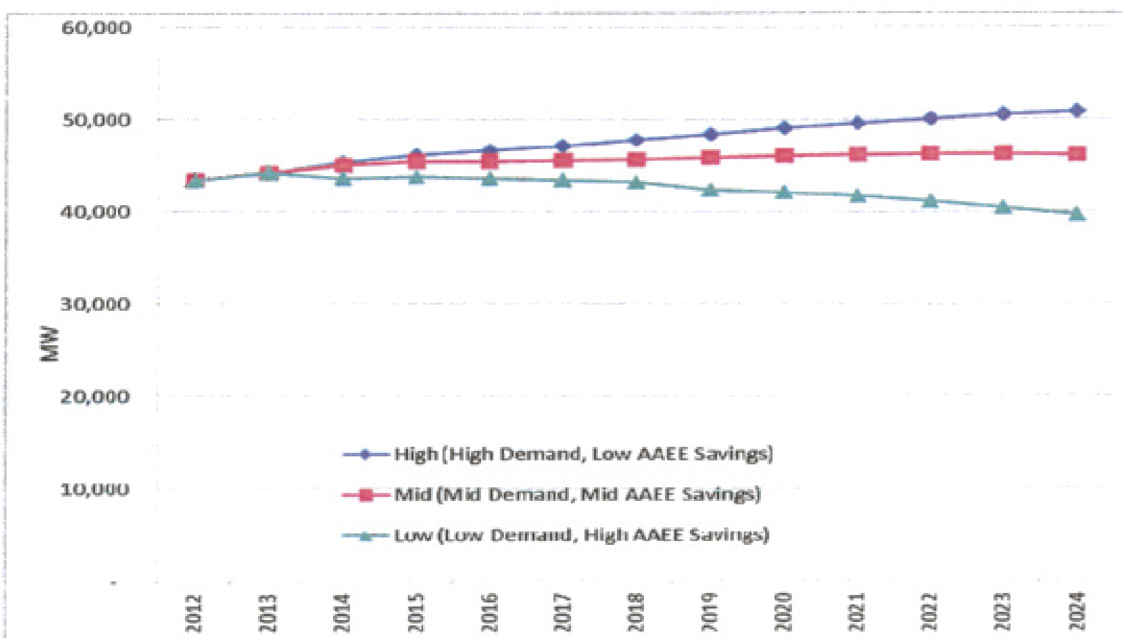
CED 2013 Final includes estimates of additional achievable (uncommitted) energy efficiency for the investor-owned utility service territories. These savings are not yet considered committed but are deemed reasonably likely to occur, and include impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2014. Five different savings scenarios were developed. This report shows the impact of additional achievable electricity consumption, peak demand, and natural gas consumption savings incorporated in adjusted (relative to the baseline) forecasts for these service territories. **Figure ES-4** and **Figure ES-5** show adjusted forecasts for electricity sales and peak demand, respectively, for the combined investor-owned utility service territories, where additional achievable savings from the low scenario are combined with the high demand baseline case, savings from the high scenario are combined with the low demand baseline case, and mid scenario savings are paired with the mid demand baseline case. These savings have a significant impact on projected sales and peak: the adjusted mid case totals for sales and peak are around 10 percent lower (about 21,000 GWh and 5,200 MW, respectively) than the baseline mid demand case by 2024.

Figure ES-4: Adjusted Demand Scenarios for Electricity Sales, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013.

Figure ES-5: Adjusted Demand Scenarios for Peak, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013.

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Summary of Changes to Forecast

The previous adopted forecast, *CED 2011*, was based on historical data available at the time the forecast was developed. For *CED 2013 Final*, staff added 2011 and 2012 energy consumption data and 2012 and 2013 peak data to the historical series used for forecasting. The peak demand forecast incorporates 2012 and 2013 analysis of the temperature-peak demand relationship at the planning area level.

For *CED 2011*, econometric models were estimated for the residential, commercial, and industrial electricity sectors. *CED 2013 Final* adds econometric models for the other electricity sectors (agriculture and water pumping; transportation, communications, and utilities; and street lighting), as well as for the major natural gas sectors. Adjustments were made to existing models based on the econometric estimations. In addition, staff is developing a new industrial end-use energy model. Although this model is not yet complete, enough progress has been made to allow use in *CED 2013 Final*.

As part of the continuing effort to capture comprehensively the impacts of energy efficiency initiatives, *CED 2013 Final* incorporates recent revisions to Energy Commission building codes and appliance standards and projected savings from the 2013–2014 California Public Utilities Commission efficiency program cycle for investor-owned utilities and from 2013 programs for the publicly owned utilities. Along with these new committed efficiency initiatives, *CED 2013 Final* provides estimates of additional achievable energy efficiency savings for the investor-owned utility service territories. This report presents both baseline and adjusted forecasts for these areas.

In addition to a predictive model to forecast residential adoption of photovoltaic systems and solar water heaters used in *CED 2011*, *CED 2013 Final* employs a predictive model for the commercial sector that projects adoption of combined heat and power and photovoltaic systems. These models are based on methods used by the United States Energy Information Administration, as part of its National Energy Modeling System, and the National Renewable Energy Laboratory.

CED 2011 included estimates of potential climate change impacts on peak demand. Along with an updated peak demand analysis, *CED 2013 Final* incorporates estimates of climate change impacts on electricity and natural gas consumption. These impacts were developed using temperature scenarios provided by the Scripps Institute of Oceanography.

Stakeholders have expressed a strong interest in a more disaggregated demand forecast to better inform resource and infrastructure-related analyses and decisions. As a first step in this direction, staff developed results at the climate zone level for *CED 2013 Final* in addition to the usual utility planning area forecasts. The appropriate level of disaggregation for future forecasts, given data and other resource constraints, will be determined through internal discussions and input from stakeholders after the *CED 2013* forecast cycle.

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Table 7: Energy Prices, *CED 2013 Final* Forecast

Electricity			
Year/Period	High Demand Scenario	Mid Demand Scenario	Low Demand Scenario
	Average Price (2012 cents/kWh)		
2012	13.4	13.4	13.4
2015	14.0	14.6	15.2
2020	14.2	15.7	17.2
2024	14.9	16.4	18.0
	Percentage Change vs. 2012		
2012-2015	4.4%	8.8%	13.3%
2012-2020	5.8%	16.7%	27.8%
2012-2024	10.5%	21.9%	33.6%
Natural Gas			
Year/Period	High Demand	Mid Demand	Low Demand
	Average Delivered Cost (2012$/therm)		
2012	0.64	0.64	0.64
2015	0.86	0.92	1.10
2020	0.91	1.08	1.34
2024	1.02	1.18	1.42
	Percentage Change vs. 2012		
2012-2015	33.8%	43.5%	70.8%
2012-2020	41.6%	67.1%	108.0%
2012-2024	58.1%	83.6%	119.9%

Source: California Energy Commission, Demand Analysis Office, 2013.

Conservation/Efficiency Impacts

Energy Commission demand forecasts seek to account for efficiency and conservation *reasonably expected to occur*. Since the *1985 Electricity Report*, reasonably expected to occur initiatives have been split into two types: committed and uncommitted, or achievable. The baseline forecasts in *CED 2013 Final* continue that distinction, with only committed efficiency included. Committed initiatives include utility and public agency programs, codes and standards, and legislation and ordinances having final authorization, firm funding, and a design that can be readily translated into characteristics capable of being evaluated and used to estimate future impacts (for example, a package of IOU incentive programs that has been funded by CPUC order). In addition, committed impacts include price and other market effects not directly related to a specific initiative. Chapter 3 details the committed energy efficiency impacts projected for this forecast.

CED 2013 Final also includes estimates of AAEE savings for the investor-owned utility service territories. These savings are not yet considered committed but are deemed reasonably likely to occur, and include impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2014. Five different savings scenarios were developed. Chapter 4 shows the impact of additional achievable electricity consumption and peak savings as well as natural gas consumption savings incorporated in adjusted (relative to the baseline) forecasts for these service territories.

Demand Response

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

Non-event-based program impacts are likely to increase in the coming years, and expected impacts incremental to the last historical year for peak (2012) affect the demand forecast.[26] Staff, in consultation with the IOUs and the CPUC, identified impacts from current committed demand response programs in these planning areas, which include real-time or time-of-use pricing and permanent load shifting. Impacts are shown in **Table 8**.

Table 8: Estimated Non-Event-Based Demand Response Program Impacts (MW)

Year	PG&E	SCE	SDG&E
2012	21	13	1
2013	16	18	4
2014	35	33	4
2015	35	33	4
2016	35	33	4
2017	35	33	4
2018	35	33	4
2019	35	33	4
2020	35	33	4
2021	35	33	4
2022	35	33	4
2023	35	33	4
2024*	35	33	4
*Program cycles end in 2023; 2024 values assumed the same as 2023.			

Source: California Energy Commission, Demand Analysis Office, 2013.

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

CHAPTER 4: Additional Achievable Energy Efficiency

Background

Committed efficiency savings reflect savings from initiatives that have been approved, finalized, and funded, whether already implemented or not. There are also likely additional savings from initiatives that are neither finalized nor funded but are reasonably expected to occur, including impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2014 (program measures). These savings are referred to as *achievable*. Resource and transmission planners now require an adjustment to the Energy Commission's baseline forecasts (which include only committed savings) to account for these likely impacts.

Achievable savings estimates begin with a comprehensive efficiency potential study, as provided in the *2013 California Energy Efficiency Potential and Goals Study (2013 Potential Study)*, completed for the California Public Utilities Commission (CPUC) by Navigant Consulting, Inc., in August 2013.[69] The *2013 Potential Study* estimated energy efficiency savings that could be realized through utility programs as well as codes and standards within the investor-owned utility (IOU) service territories for 2006-2024,[70] given current or soon-to-be-available technologies. Because many of these savings are already incorporated in the Energy Commission's current *CED 2013 Final* baseline forecasts, staff needed to estimate the portion of savings from the *2013 Potential Study* not accounted for in the these forecasts. These nonoverlapping savings are referred to as *additional achievable energy efficiency* (AAEE) impacts.

Staff developed five AAEE scenarios, based on recommendations from the Joint Agency Steering Committee[71] and input from Navigant and forecast stakeholders through the Demand Analysis Working Group (DAWG). These scenarios varied by assumptions related to economic growth, changes in electricity and natural gas rates, and a host of inputs associated with efficiency measure adoption and the impact of building codes and appliance standards. These variations in input assumptions across the five scenarios are shown in **Table 34**.

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69 Available at http://demandanalysisworkinggroup.org/documents/2013_08_16_ES_Pup_EE_Pot_final/CA_PGT_Model_2012_2013_Release_Aug_2013.ana.zip

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

71 The Joint Agency Steering Committee is composed of managerial representatives from the Energy Commission, the California Independent System Operator, and the California Public Utilities Commission and is committed to improving coordination and process alignment across state planning processes that use the Energy Commission's demand forecast.

This chapter summarizes the AAEE results, describes the scenarios and method used to develop these estimates, and shows adjusted forecasts for the combined IOUs. Adjusted forecasts for individual IOU service territories are provided in the electricity planning area chapters in Volume II of this report and in Chapter 2 of this volume. Detailed results for AAEE savings at the utility level are included in the demand forms accompanying this report.[72] AAEE electricity savings were estimated for the PG&E, SCE, and SDG&E service territories. Natural gas savings were estimated for the PG&E, SDG&E, and SoCalGas gas service territories.

Summary of Results

Figure 43, **Figure 44**, and **Figure 45** show estimated AAEE savings by scenario for the IOUs combined in GWh, MW, and million therms, respectively. AAEE savings begin in 2013 because 2012 was the last recorded historical year for consumption in *CED 2013 Final*. As discussed in more detail in the next section, Scenario 3 represents a "most likely" (in terms of scenario definition), or mid case, while Scenario 1 (low savings) and Scenario 5 (high savings) are meant to provide a range of outcomes through pessimistic and optimistic assumptions, respectively, regarding efficiency measure adoption and standards implementation. Scenarios 2 (low mid savings) and 4 (high mid savings) are similar to Scenarios 1 and 5, respectively, but assume the same economic growth and energy prices as Scenario 3, and are constructed to provide alternatives to Scenario 3.

By 2024, AAEE savings reach nearly 21,000 GWh, almost 5,000 MW, and more than 400 million therms in the mid case. The high case reaches around 34,000 GWh, 8,000 MW, and 500 million therms in this year, while projected totals in the low scenario are about 12,000 GWh, 3,000 MW, and 300 million therms in 2024. As indicated, totals for the low mid and high mid scenarios are very similar to the high and low cases, respectively. Natural gas savings are slightly negative in 2013 and 2014 in all scenarios, a reflection of *interactive* effects modeled in the *2013 Potential Study* that result from slightly higher gas heating requirements as lighting efficiencies improve.

72 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

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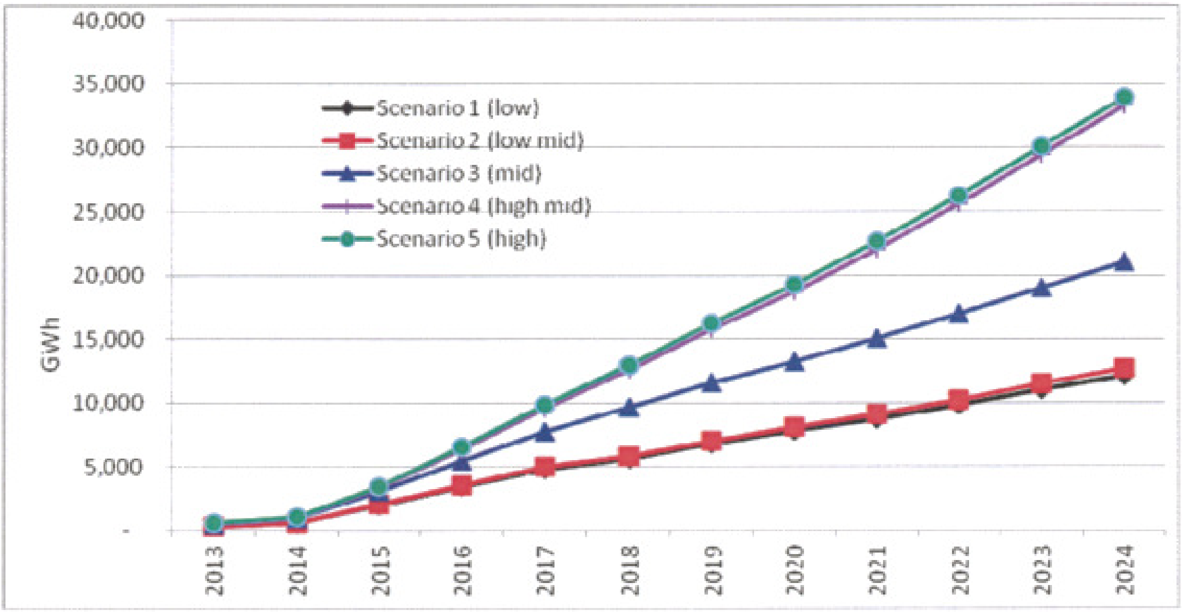
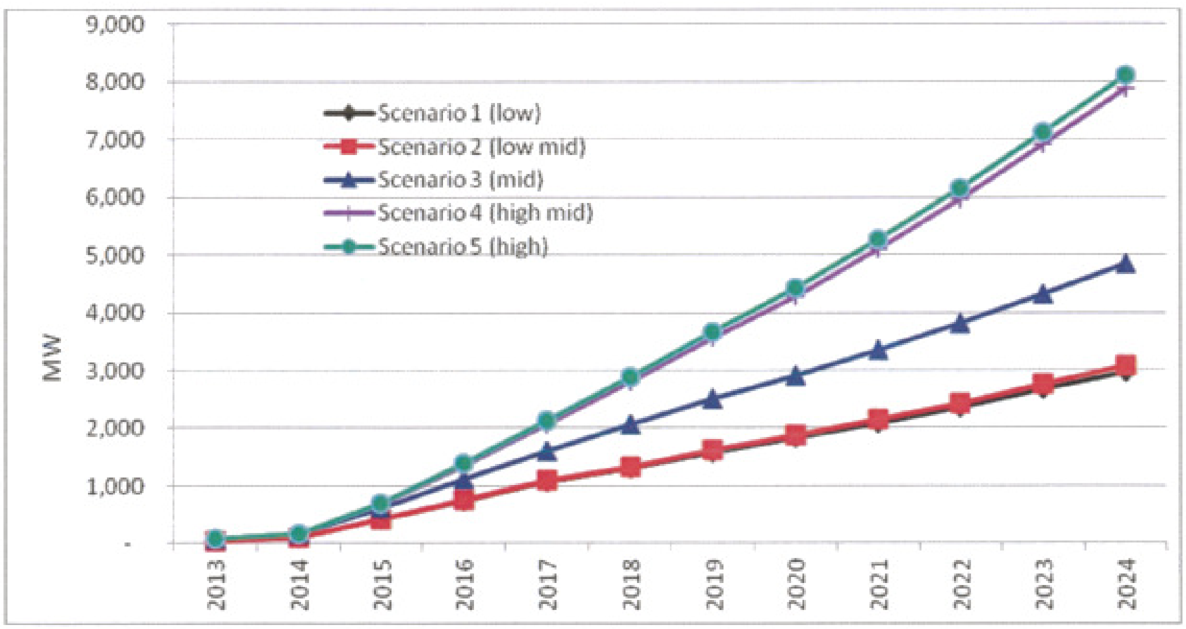
Figure 43: AAEE Savings for Electricity (GWh) by Scenario, Combined IOUs



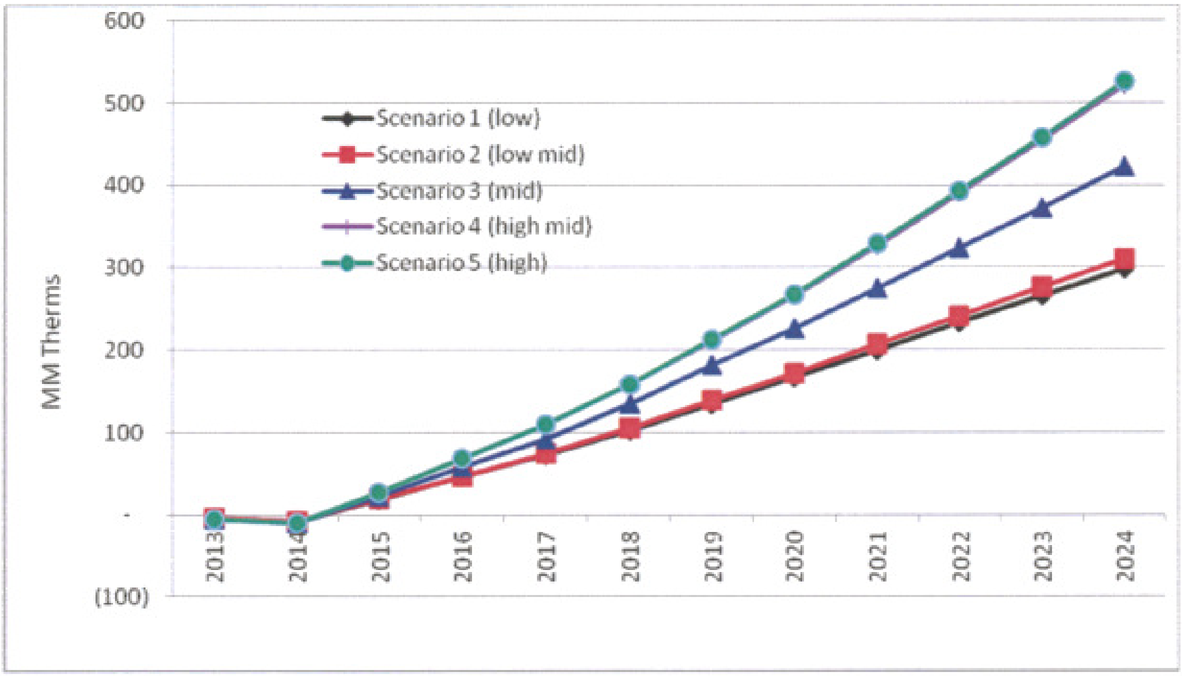
Source: California Energy Commission, Demand Analysis Office, 2013

Figure 44: AAEE Savings for Electricity Peak Demand (MW) by Scenario, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 45: AAEE Savings for Natural Gas (MM therms) by Scenario, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

Table 27 shows combined IOU AAEE savings by type (program measures and standards) in the mid scenario. The proportion of savings attributed to standards is reduced relative to the *2013 Potential Study* since most of the overlapping lighting savings from *CED 2013 Final* were deducted from standards. (See next section.) **Table 28** provides the totals by type in 2024 for all five scenarios. The standards proportion of savings increases in the higher scenarios (3-5) with the introduction of future Title 24 and Title 20 standards. In the low and low mid scenarios, the only AAEE standards savings come from federal standards, and the associated lighting efficiency improvements result in negative natural gas savings throughout the forecast period. In 2013 and 2014, the only program measure savings come from behavioral programs, and Navigant does not provide peak savings for this category.

Table 27: AAEE Savings by Type, Combined IOUs, Mid Savings Scenario

Year	GWh			MW			MM Therms		
	Program Measures	Standards	Total	Program Measures	Standards	Total	Program Measures	Standards	Total
2013	24	506	531	-	77	77	1	(7)	(6)
2014	48	883	931	-	157	157	2	(13)	(11)
2015	1,523	1,504	3,027	247	350	597	37	(15)	22
2016	3,058	2,393	5,451	500	614	1,115	72	(15)	57
2017	4,512	3,237	7,749	750	846	1,596	107	(14)	92
2018	5,461	4,154	9,614	942	1,114	2,056	145	(10)	135
2019	6,662	4,865	11,528	1,162	1,341	2,503	186	(4)	182
2020	7,700	5,558	13,258	1,339	1,575	2,914	224	3	226
2021	8,882	6,213	15,095	1,551	1,807	3,357	265	10	274
2022	10,141	6,822	16,963	1,783	2,035	3,818	307	16	323
2023	11,591	7,375	18,965	2,074	2,252	4,326	350	22	372
2024	13,094	7,896	20,990	2,379	2,462	4,841	394	28	422

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

Table 28: Combined IOU AAEE Savings by Type, 2024

		Scenario 1 (low)	Scenario 2 (low mid)	Scenario 3 (mid)	Scenario 4 (high mid)	Scenario 5 (high)
GWh	Program Measures	8,160	8,538	13,094	21,255	21,269
	Standards	4,006	4,161	7,896	12,039	12,678
	Total	12,166	12,699	20,990	33,293	33,947
MW	Program Measures	1,495	1,570	2,379	4,136	4,175
	Standards	1,468	1,493	2,462	3,738	3,926
	Total	2,963	3,063	4,841	7,874	8,101
Million Therms	Program Measures	300	312	394	504	506
	Standards	(2)	(2)	28	18	20
	Total	298	310	422	522	526

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

Table 29 shows the combined IOU AAEE savings for the mid scenario by sector in selected years. The distribution reflects Navigant's conclusion that the largest share of remaining energy efficiency potential resides in the commercial sector. For peak demand, residential savings are closer to commercial because the residential sector tends to have higher peak demand relative to average load. **Table 30** provides savings by sector for all scenarios in 2024.

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Table 29: Combined IOU AAEE Savings by Sector, Mid Savings Scenario

	Sector	2013	2016	2019	2022	2024
GWh	Residential	91	1,138	2,849	4,790	5,749
	Commercial	425	3,629	7,055	9,655	12,140
	Industrial	15	412	936	1,415	1,720
	Agricultural	-	208	529	854	1,071
	Street-Lighting	-	65	159	250	310
	All Sectors	531	5,451	11,528	16,963	20,990
MW	Residential	15	450	1,105	1,754	2,156
	Commercial	61	607	1,266	1,862	2,436
	Industrial	2	41	90	135	164
	Agricultural	-	17	42	68	85
	Street-Lighting	-	-	-	-	-
	All Sectors	77	1,115	2,503	3,818	4,841
Million Therms	Residential	(3)	11	55	110	150
	Commercial	(3)	8	33	66	90
	Industrial	-	35	85	134	165
	Agricultural	-	3	8	13	17
	Street-Lighting	-	-	-	-	-
	All Sectors	(6)	57	182	323	422

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

Table 30: Combined IOU AAEE Savings by Sector, 2024

	Sector	Scenario 1 (low)	Scenario 2 (low mid)	Scenario 3 (mid)	Scenario 4 (high mid)	Scenario 5 (high)
GWh	Residential	2,727	2,786	5,749	7,288	7,550
	Commercial	7,117	7,584	12,140	21,498	21,853
	Industrial	1,345	1,348	1,720	2,516	2,547
	Agricultural	794	794	1,071	1,336	1,339
	Street-Lighting	184	187	310	655	657
	All Sectors	12,166	12,699	20,990	33,293	33,947
MW	Residential	1,421	1,424	2,156	2,465	2,598
	Commercial	1,347	1,443	2,436	5,097	5,188
	Industrial	131	132	164	207	209
	Agricultural	64	64	85	106	106
	Street-Lighting	-	-	-	-	-
	All Sectors	2,963	3,063	4,841	7,874	8,101
Million Therms	Residential	76	85	150	216	219
	Commercial	82	84	90	88	88
	Industrial	128	129	165	197	197
	Agricultural	12	12	17	21	21
	Street-Lighting	-	-	-	-	-
	All Sectors	298	310	422	522	526

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

Table 31 shows the savings impact of emerging technologies across all scenarios for the combined IOUs in selected years. This category encompasses technologies that are not yet available in today's market or at very low penetration levels but expected to become commercially viable during the forecast period. For electricity, most of the savings from emerging technologies comes from light-emitting diode (LED) lighting and new air-conditioning technologies. Natural gas savings come mainly from new furnace and dishwasher technologies.

As indicated in the next section, assumptions for emerging technologies varied significantly among the scenarios, both in terms of cost-benefit adoption criteria and adjustments to the Navigant model results. For GWh, the percentage of total AAEE savings provided by emerging technologies ranges from 2 percent in Scenario 1 to 29 percent in Scenario 4.

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Table 31: Combined IOU Emerging Technology Savings by Scenario

	Year	Scenario 1 (low)	Scenario 2 (low mid)	Scenario 3 (mid)	Scenario 4 (high mid)	Scenario 5 (high)
GWh	2015	10	20	99	291	290
	2018	53	107	613	1,704	1,754
	2020	102	206	1,201	3,583	3,677
	2022	176	356	2,127	6,320	6,322
	2024	281	599	3,369	9,735	9,660
MW	2015	1	1	9	31	30
	2018	6	12	77	258	259
	2020	14	28	174	597	597
	2022	27	55	341	1,123	1,127
	2024	47	96	575	1,841	1,827
Million	2015	0	0	0	0	0
Therms	2018	1	2	5	10	9
	2020	2	4	13	28	27
	2022	4	8	26	56	55
	2024	6	13	44	96	92

Source: California Energy Commission, Demand Analysis Office, 2013

Table 32 provides AAEE savings by individual IOU in the mid savings scenario for selected years. Total savings are generally a function of total sales or peak demand in each IOU, although electricity savings percentages (relative to sales or peak) are slightly lower for SDG&E because of less potential in the agricultural and industrial sectors. **Table 33** provides savings by IOU by scenario for 2024.

Table 32: AAEE Savings by IOU, Mid Savings Scenario

	Utility	2013	2016	2019	2022	2024
GWh	PG&E	225	2,335	4,998	7,431	9,208
	SCE	264	2,579	5,378	7,806	9,628
	SDG&E	42	538	1,152	1,727	2,154
	Total IOU	531	5,451	11,528	16,963	20,990
MW	PG&E	33	476	1,088	1,684	2,141
	SCE	38	523	1,152	1,728	2,183
	SDG&E	6	116	264	406	518
	Total IOU	77	1,115	2,503	3,818	4,841
Million Therms	PG&E	(2)	24	78	141	184
	SoCalGas	(4)	30	93	162	210
	SDG&E	(0)	3	11	21	28
	Total IOU	(6)	57	182	323	422

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

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Table 33: AAEE Savings by IOU and Scenario, 2024

	Utility	Scenario 1 (low)	Scenario 2 (low mid)	Scenario 3 (mid)	Scenario 4 (high mid)	Scenario 5 (high)
GWh	PG&E	5,332	5,562	9,208	14,646	14,924
	SCE	5,554	5,748	9,628	15,205	15,492
	SDG&E	1,280	1,389	2,154	3,442	3,530
	Total IOU	12,166	12,699	20,990	33,293	33,947
MW	PG&E	1,274	1,319	2,141	3,514	3,613
	SCE	1,367	1,401	2,183	3,544	3,632
	SDG&E	322	342	518	816	856
	Total IOU	2,963	3,063	4,841	7,874	8,101
Million Therms	PG&E	131	137	184	229	229
	SoCalGas	147	152	210	254	256
	SDG&E	20	22	28	38	41
	Total IOU	298	310	422	522	526

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

Method and Scenarios

Navigant Consulting provided invaluable assistance in developing the AAEE savings estimates, including training Energy Commission staff in the use of the model employed in the CPUC's *2013 Potential Study,* referred to as the Potential, Goals, and Targets (PGT) model. The PGT model includes methodologies to estimate program measure savings, savings from codes and standards, and savings from behavioral programs. Navigant developed a modified version of the PGT model specifically for this effort.

For a user-defined scenario, the PGT model estimates gross and net[73] first-year and cumulative technical, economic, and market potential efficiency impacts from the three sources of savings beginning in 2006 for electricity consumption, peak demand, and natural gas consumption.[74] In general, the effort to characterize AAEE savings consists of determining the portion of estimated net market potential in a given scenario not incorporated in the *CED 2013 Final* baseline forecast. For program measures, AAEE includes net accumulated market savings beginning in 2015,[75] since *CED 2013 Final* incorporates utility programs through 2014. For standards, AAEE consists of net savings from expected (or recently finalized) regulations not

73 Net savings equals gross savings minus naturally occurring market savings, or "free ridership" savings that would be expected to occur without any efficiency initiative.

74 Natural gas consumption savings estimates incorporate *interactive* effects and thus can be negative for certain categories in the detailed results.

75 There are a small amount of behavior-related savings included starting in 2013.

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included in *CED 2013 Final*, and the PGT model is set up to calculate estimated savings for the following:

- 2016 Title 20 standards
- Adopted and future federal appliance standards
- 2016, 2019, and 2022 Title 24 standards.

Specific elements assumed for each set of standards are provided in the *2013 Potential Study* report. As shown below, the specific standards included varied with the scenario.

The *CED 2013 Final* forecasts include a substantial amount of lighting savings in anticipation of the effects of Assembly Bill 1109 (AB 1109, Huffman, Chapter 534, Statutes of 2007) through future programs and Title 20 standards. These savings can be expected to overlap with lighting savings estimated in any given PGT-modeled scenario. To account for this overlap, Energy Commission staff subtracted *CED 2013 Final* lighting savings accumulating during the forecast period from future standards and program lighting savings estimated by the PGT model for each scenario.

The PGT model requires a variety of inputs and input assumptions from which savings scenarios can be developed. The following summarizes the parameters used in constructing the five scenarios. More information can be found in the *2013 Potential Study* report.

1. *Incremental Costs*: Incremental costs are the difference in costs between code- or standard-level equipment and the higher-efficiency equipment under consideration. The incremental costs for efficient technologies come from the Database for Energy Efficiency Resources (DEER) – the CPUC-approved database for various energy savings parameters.
2. *Implied Discount Rate*: The implied discount rate is the effective discount rate that consumers apply when making a purchase decision; it determines the value of savings in a future period relative to the present. The implied discount rate is higher than standard discount rates used in other analyses because it is meant to account for market barriers that may impact customer decisions.
3. *Marketing and Word of Mouth Effects*: The base factors for market adoption are a customer's willingness to adopt and awareness of efficient technologies, which were derived from a regression analysis of technology adoptions from several studies on technology diffusion. Each end use in each sector was assigned marketing and word-of-mouth effectiveness factors corresponding to diffusion rates in the studies.
4. *TRC Threshold*: The Total Resource Cost (TRC) is the primary cost-effectiveness indicator that the CPUC uses to determine funding levels and adoption thresholds for energy efficiency. The TRC test measures the net resource benefits from the perspective of all ratepayers by combining the net benefits of the program to participants and nonparticipants. A TRC threshold of 1.0 means that the benefits of a program or measure must at least equal the costs. The CPUC uses a TRC of 0.85 as a "rule of thumb," allowing

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programs to include marginal yet promising measures. For emerging technologies, an even lower threshold is typically used.

5. *Efficient Measure Density*: *Measure density* is defined as the number of units of a technology per unit area. Higher densities for efficient technologies mean more familiarity and a greater likelihood of adoption, all else equal. Specifically, measure density is categorized as follows:
    - *Baseline measure density:* the number of units of a baseline technology per home for the residential sector, or per unit of floor space for the commercial sector.
    - *Energy-efficient measure density*: the number of energy-efficient units existing per home for the residential sector, or per unit of floor space for the commercial sector.
    - *Total measure density:* typically the sum of the baseline and efficient measure density. When two or more efficient measures compete to replace the same baseline measure, then the total density is equal to the sum of the baseline density and all applicable energy-efficient technology densities.

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

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

In addition, assumptions regarding future standards and associated compliance rates, economic growth (in the form of increases in building stock), energy prices, and avoided costs varied among the scenarios.

Table 34 shows the input assumptions for the five scenarios. For the low, mid, and high savings cases, building stock, prices, and avoided costs were designed to be consistent with the three baseline *CED 2013 Final* scenarios, which combine high economic growth, lower efficiency program savings, and lower rates in the high demand case and lower growth, higher program savings, and higher rates in the low demand case. For the adjusted forecasts, therefore, the low AAEE savings case is paired with the high demand baseline and the high savings case with the low demand baseline. The low mid and high mid cases (Scenarios 2 and 4) use the same building stock and price assumptions as the mid savings case to provide consistent alternatives to the mid savings case with respect to these assumptions for planning purposes.

The low and low mid savings cases assume a 20 percent decrease in compliance rates compared to base compliance rates developed by Navigant.[76] The high savings case assumes compliance

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76 Base compliance rates are derived from CPUC. *Final Evaluation Report, Codes & Standards (C&S) Programs Impact Evaluation, California Investor Owned Utilities' Codes and Standards Program Evaluation for*

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rates that increase above the base levels, to a maximum of 100 percent by the end of the forecast period.[77] In the high mid and high cases, additional likely (but not adopted) federal appliance standards are introduced.

Future lighting savings in *CED 2013 Final* varied by baseline demand scenario, so the amount of overlapping lighting savings to be subtracted from future lighting savings output by the PGT model depended on the savings scenario. In the low savings case, future lighting savings associated with the high demand baseline forecast were deducted, while savings from the low demand baseline forecast were deducted in the high savings case (and mid demand savings in the three mid savings scenarios).[78]

Program Years 2006-2008. Prepared by KEMA, Inc., The Cadmus Group, Inc., Itron, Inc., and Nexus Market Research, Inc.

77 Whether 100 percent compliance is reached depends on the date of introduction of the standards.

78 The amount of overlapping lighting savings increased over the forecast period, reaching 3,100 GWh in the *CED 2013 Revised* low demand forecast, 3,200 GWh in the mid demand case, and 3,350 GWh in the high case in 2024. Associated peak demand overlap reached 430 MW, 450 MW, and 470 MW, respectively.

Table 34: AAEE Savings Scenarios

Scenario Number	1	2	3	4	5
Scenario Name	Low Savings	Low Mid Savings	Mid Savings	High Mid Savings	High Savings
ET's	25% of model Results	50% of model Results	100% of model results	150% of Model Results	150% of Model Results
Building Stock	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
Retail Prices	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
Avoided Costs	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
UES	Estimate minus 25%	Estimate minus 25%	Best Estimate UES	Estimate plus 25%	Estimate plus 25%
Incremental Costs	Estimate plus 20%	Estimate plus 20%	Best Estimate Costs	Estimate minus 20%	Estimate minus 20%
Incentive Level	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost
TRC Threshold	1	1	0.85	0.75	0.75
ET TRC Threshold	0.85	0.85	0.5	0.4	0.4
Measure Densities	Estimate minus 20%	Estimate minus 20%	Best Estimate Costs	Estimate plus 20%	Estimate plus 20%
Word of Mouth Effect*	39%	39%	43%	47%	47%
Marketing Effect*	1%	1%	2%	3%	3%
Implied Discount Rate	20%	20%	18%	14%	14%
Standards Compliance	No Compliance Enhancements, Compliance Rates Reduced by 20 percent	No Compliance Enhancements, Compliance Rates Reduced by 20 percent	No Compliance Enhancements	No Compliance Enhancements	Compliance Enhancements
Title 24 Updates	None	None	2016, 2019, 2022	2016, 2019, 2022	2016, 2019, 2022
Title 20 Updates	None	None	2016-2018	2016-2018	2016-2018
Federal Standards	Already adopted	Already adopted	Already adopted	Future Federal Standards	Future Federal Standards

Sources: Navigant Consulting and California Energy Commission, Demand Analysis Office, 2013

To arrive at a final set of scenarios, staff first solicited stakeholder input through the DAWG. Stakeholders were provided a preliminary set of savings scenarios based on three cases presented in the *2013 Potential Study* report as well as additional scenarios developed by Energy Commission staff as variations around the *2013 Potential Study* mid case results. In this manner, stakeholders expressed their preferences for a specific scenario and commented on individual input assumptions. Eight stakeholder groups submitted written comments: the Efficiency Council, the Natural Resources Defense Council, the California Independent System Operator, the Independent Energy Producers, PG&E, SCE, SDG&E, and SoCalGas. Stakeholder comments are posted on the DAWG website.[79] The Joint Agency Steering Committee reviewed these comments and, through discussions with CPUC and Energy Commission staff, developed proposed recommendations for the scenarios.

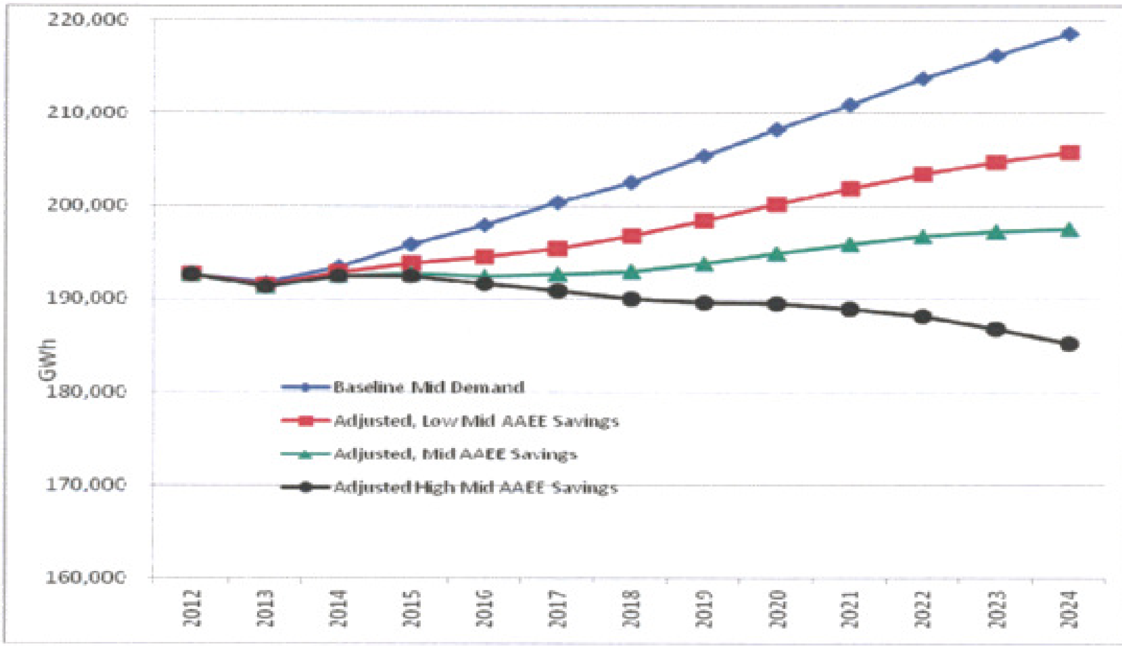
Adjusted Forecasts

Staff develops the baseline forecasts for consumption, sales, and peak demand at the planning area level. However, the AAEE savings presented in this chapter are meant to be applied to service territories, which are a subset of the associated planning areas in the case of PG&E, SCE, and SoCalGas. To develop baseline forecasts for these service territories, staff applies a similar rate of growth as the planning areas to service territory sales and peak in the last historical year (2012 and 2013). Adjusted forecasts presented in this section are for the four IOU service territories (or the sum of service territories).

Figure 46, **Figure 47**, and **Figure 48** show the effects of the estimated low mid, mid, and high mid AAEE savings on *CED 2013 Final* mid baseline demand for the combined IOU service territories for electricity sales, peak demand, and end-user natural gas sales. Adjusted electricity sales and peak demand increase slightly using the low mid AAEE scenario, are relatively flat using the mid savings case, and decline with the low mid savings case. Natural gas sales, already relatively flat in the mid baseline forecast, decline after adjustments with all AAEE three savings scenarios.

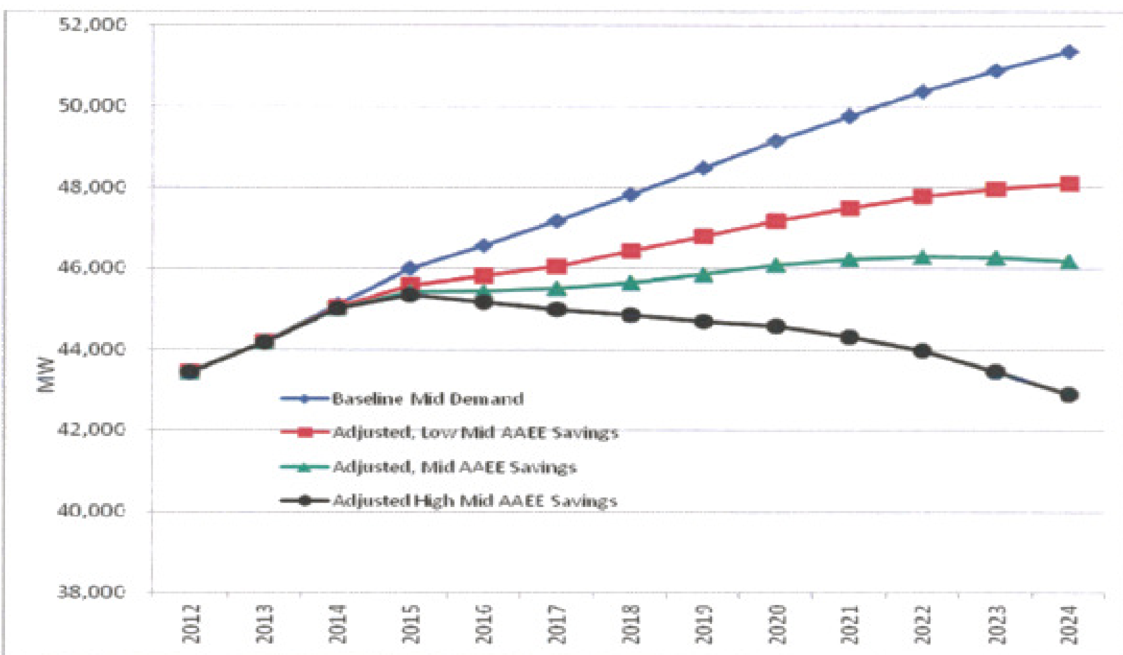
79 http://demandanalysisworkinggroup.org/?p=844

Figure 46: Baseline Mid Demand Electricity and Adjusted Sales, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 47: Baseline Mid Demand and Adjusted Peaks, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

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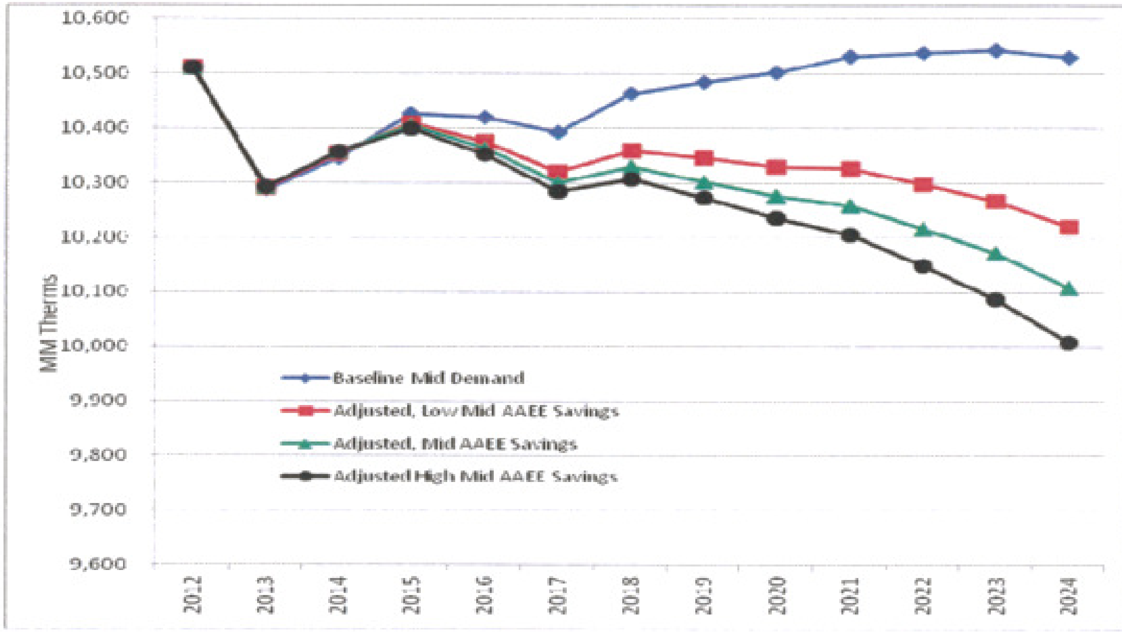
Figure 48: Baseline Mid Demand and Adjusted End-User Natural Gas Sales, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 49, **Figure 50**, and **Figure 51** show the *CED 2013 Final* high demand, mid demand, and low demand baseline forecasts when adjusted by low AAEE savings, mid savings, and high savings, respectively, for the combined IOUs. Relative to the baseline forecasts, electricity sales in 2024 are reduced by 5.3 percent, 9.6 percent, and 16.4 percent for the high, low, and mid demand cases, respectively. Peak demand is reduced by 5.9 percent, 10.1 percent, and 18.0 percent, respectively, in 2024. Natural gas sales decline in all three adjusted scenarios, and are reduced by 2.8 percent, 4.0 percent, and 5.1 percent, respectively, from baseline levels in 2024. Numbers corresponding to these graphs are provided in the demand forms accompanying this report.[80]

The adjusted service territory forecasts provided in this report constitute options to form the basis for a "managed" forecast to be used for planning purposes in Energy Commission, CPUC, and California ISO proceedings. The choice of scenarios (baseline and AAEE) to use for this purpose will be made by the leadership of these agencies shortly after this report is adopted on December 11, 2013 and documented in the adopted *2013 IEPR*.

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80 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

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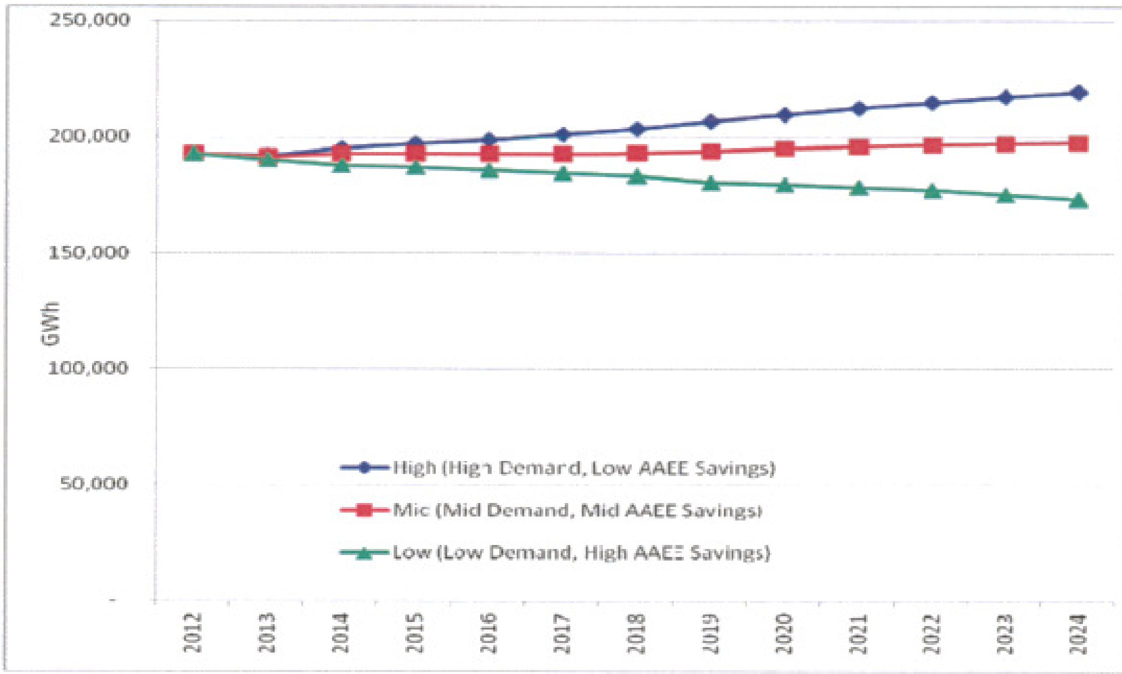
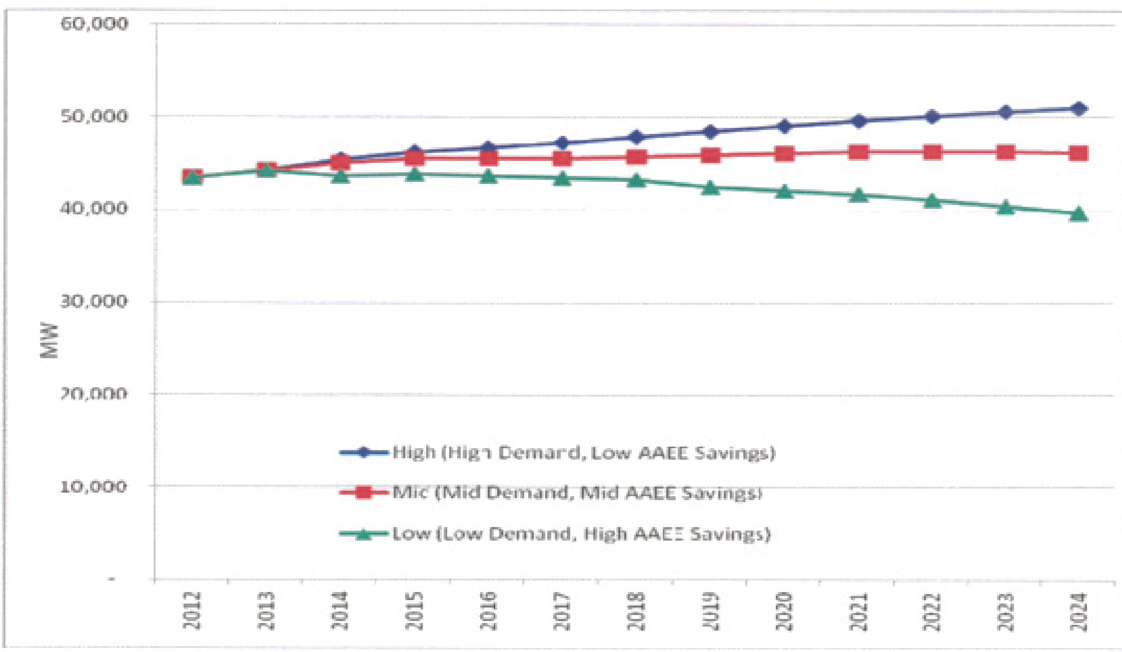
Figure 49: Adjusted Demand Scenarios for Electricity Sales, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 50: Adjusted Demand Scenarios for Peak, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

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