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# IMPACT OF ASSEMBLY BILL 32 SCOPING PLAN ELECTRICITY RESOURCE GOALS ON NEW NATURAL GAS-FIRED GENERATION

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**CALIFORNIA ENERGY COMMISSION**

Angela Tanghetti
***Principal Analyst***

Karen Griffin
***Project Manager***

Al Alvarado
***Manager***
**ELECTRICITY ANALYSIS OFFICE**

Sylvia Bender
***Deputy Director***
**ELECTRICITY SUPPLY ANALYSIS DIVISION**

Melissa Jones
***Executive Director***

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# Table of Contents

# List of Tables

# Abstract

The study assesses how implementing the electricity resource policies in the California Air Resources Board's Assembly Bill 32 (AB 32) (Núñez, Chapter 488, Statutes 2006) *Climate Change Scoping Plan* along with once-through cooling policies would affect natural gas use and generation.

The analysis began with a focus on the impact of intermittent wind and solar on the need for and location of new natural gas-fired generation. California Energy Commission staff tested this using the Scoping Plan resource policies, on the hypothesis that the other Scoping Plan programs would impact how well the electricity system performed when adding intermittent wind or solar. Staff developed three statewide Renewables Portfolio Standard cases, one to provide a reference case and two "bookend" estimates. The Reference case does not include the Scoping Plan policies, only the assumption that the 20 percent Renewables Portfolio Standard is met by 2012 statewide. The two bookend cases include the Scoping Plan policies, including 33 percent Renewables Portfolio Standard statewide. These two bookend cases differed by the quantity of wind or central station solar added to meet a 33 percent Renewables Portfolio Standard by 2020 (High Solar and High Wind). The study also implements a compliance plan for the State Water Resources Control Board's pending policy to reduce the adverse impacts of once-through cooling from coastal gas-fired power plants. Within these constraints, the study examines whether the type of intermittent renewable added has a significant impact on the location and amount of incremental natural gas generation to serve local area and inertia requirements of the system.

The study found that three-fifths of electric generation savings are anticipated to come from complementary measures (energy efficiency, combined heat and power, and rooftop photovoltaic) and two-fifths from renewable resources. Both the High Solar and High Wind cases reduced overall natural gas use by 15 percent. Three-quarters of the gas reductions occurred out-of-state; within California, even more in-state gas generation was needed in the High Wind case. The natural gas results were heavily influenced by the planned replacement or retrofit of coastal units, which currently use once-through cooling. The complementary programs of the AB 32 Scoping Plan policies also reduced the usage of these once-through cooling replacement plants, as measured by lower capacity factors, in the long term, suggesting that more analysis is needed on the attributes of current once-through cooling units that need to be replaced.



**Keywords**: AB 32 Scoping Plan, natural gas-fired generation, once-through cooling, intermittent generation, wind, solar, resource planning, electricity system, energy efficiency, load shapes, Renewables Portfolio Standard

# Executive Summary

This study is part of a multi-agency effort to further understand the integration of greater levels of renewables into California's electricity grid. It assesses how implementation of the electricity resource policies contained in the California Air Resources Board's Assembly Bill 32 (AB 32) (Núñez, Chapter 488, Statutes 2006) *Climate Change Scoping Plan* would affect natural gas use and generation. Staff developed three cases: one provides a reference case, and the other two are "bookend" estimates. The Reference case does not include the Scoping Plan policies and only assumes that the 20 percent Renewable Portfolio Standard is met by 2012 statewide. The two bookend cases include the Scoping Plan Policies as well as meeting the 33 percent Renewables Portfolio Standard by 2020 statewide. These two bookend cases differed in the amount of wind or central station solar that was added to meet a 33 percent Renewables Portfolio Standard by 2020 (High Solar and High Wind). The study implements a compliance path for the State Water Resources Control Board's pending policy to reduce the adverse impacts of once-through cooling from coastal gas-fired power plants. Within these constraints, the study examines whether the type of intermittent renewables added has a significant impact on the location and amount of incremental natural gas generation needed to serve local area and inertia requirements of the system

Case 1, the Reference case, is a starting point for measuring the impacts of the two bookend cases, Case 2 High Solar and Case 3 High Wind. Case 1 assumes no additional Scoping Plan policies beyond those included in the California Energy Commission's Integrated Energy Policy Report (IEPR) 2007 demand forecast. In contrast, Case 2 High Solar and Case 3 High Wind include the Scoping Plan policies for energy efficiency (34,707 gigawatt hours [GWh]), combined heat and power (32,304 GWh), and rooftop photovoltaic (4,845 GWh) in addition to what is already included in the Energy Commission's IEPR 2007 demand forecast. Case 1 assumes a 20 percent Renewables Portfolio Standard by 2012, while Case 2 High Solar and Case 3 High Wind build upon Case 1 and assume a 33 percent Renewables Portfolio Standard by 2020. Case 1 assumes a 2020 Renewables Portfolio Standard annual procurement target of 61,800 GWh, while Case 2 High Solar and Case 3 High Wind assume an annual procurement target of 78,000 GWh by 2020. Case 2 High Solar includes a larger amount of solar while Case 3 High Wind adds a larger amount of wind. The once-through cooling compliance plan is identical in all three cases.

By adding so many demand-reducing policies and thereby reducing the amount of incremental renewables required to reach 33 percent of retail sales, only 45,000 GWh of incremental renewables were added compared to 74,000–75,000 GWh added in studies that do not include the Scoping Plan's measures. These incremental renewables are in addition to the 33,000 GWh renewables already on-line to meet California's Renewables Portfolio Standard.

The study found that three-fifths of the electricity savings impacts from achieving Scoping Plan resource goals came from energy efficiency, rooftop photovoltaic, and combined heat and power while two-fifths of the savings came from renewables. The complementary programs both saved energy and flattened the system peak load. Statewide, the 2020 peak demand reduction of these Scoping Plan goals was 15 percent.

The study found that the potential impacts of adding large amounts of intermittent renewables on natural gas-fired generation were muted by two programs that had significant direct impacts on natural gas use and the type of plants to be built. The Scoping Plan's energy savings targets translated into an incremental 4,700 megawatts (MW) of combined heat and power. By 2020, 20 percent of all California's natural gas used for power generation was consumed by combined heat and power. This amount of combined heat and power reduced electricity sales to end-use customers but did not create a proportional reduction in natural gas use. It also added a large amount of baseload generation to Southern California, since this is where 60 percent of potential host sites for large combined heat and power are located.

The once-through cooling policies also affected the potential impacts of intermittent renewables because much of the generation that needs to be retrofitted or replaced serves local functions that continue to be supported by generation located in local reliability areas. Of the 15,069 MW of existing once-through cooling units, 964 MW were retained, 1,450 MW have recently been repowered, and 7,758 MW were replaced with new, efficient units. By 2020, depending on the case, between 11 and 23 percent of natural gas-fired generation in California is from power plants associated with the once-through cooling issue. Once combined heat and power targets and once-through cooling replacements were made, only a few new natural gas plants had to be added to meet local capacity and energy needs. Those were in the Sacramento Municipal Utility District, Turlock Irrigation District, and Imperial Valley control areas, which have no once-through cooling units and limited large hosts for new combined heat and power.

The amount of natural gas units added did not change between the base case and the two 33 percent cases. This suggests that the combined heat and power additions and those used for once-through cooling policies provided sufficient gas flexibility so that more units were not needed even in the more intermittent wind cases. But the capacity factors for generic additions and once-through cooling replacement combined cycles, which start out at normal baseload levels, drop to much lower levels by 2020 for Case 2 and 3, making the long-run cost-effectiveness of these combined cycles questionable. This suggests that the sample compliance path used in this study was not optimal if the large amount of combined heat and power baseload is added. Thus, a key finding of the study is that none of these policies should be assessed in isolation. To test these conclusions, additional model runs could be done that lower the amount of must-take combined heat and power and switch some of the once-through cooling combined cycles to combustion turbines.

For electricity generation, the Western Electricity Coordinating Council-wide amount of natural gas did decrease by 15 percent in both full Scoping Plan cases, due to the contributions of energy efficiency, rooftop photovoltaic, renewables, and combined heat and power.

Reductions were not distributed evenly; at least 70 percent of the gas reductions occurred out-of-state. In-state gas-fired generation went down only by 10 percent in the High Wind case and 13 percent in the High Solar case. In contrast, out-of-state gas-fired generation dropped 21 and 20 percent, respectively. This suggests that out-of-state natural gas is the marginal resource and that in-state gas is used for local reliability or ancillary services. In the 20 percent case, more than half of all natural gas use for electric generation is out-of-state. In the Scoping Plan cases, gas use is evenly divided between in-state and out-of-state.

With these preferred resource policies built in, the differences between the Case 3 High Wind and Case 2 High Solar cases were more modest than they would have been had less ambitious complementary programs been assessed. The study found that:

- A resource mix with a high proportion of wind required more in-state natural gas generation than Case 2 High Solar did. The High Wind case included more wind energy than an equivalent amount of solar in the High Solar case. This is consistent with the need to use gas-fired units for local reliability and the expectation that wind needs more intermittency support than does solar due to its daily load profile and greater variability.
- More impacts were seen in Southern California than Northern California. While wind is distributed across the state, solar resources are almost completely concentrated in Southern California. Once-through cooling units and potential combined heat and power sites are also concentrated in the South. This indicates that there may be more system impacts and potential system stressors in the southern transmission grid.

While gas used for serving retail load dropped, total gas use did increase. As **Table 1** shows, between 2012 and 2020, total natural gas consumption rose slightly in all cases. The increases in Case 2 and Case 3 were more modest but nonetheless increased as large amounts of combined heat and power, all fueled by natural gas, were added to the system. Those increases were less in the High Solar case than in the High Wind case when compared to the Reference case.

**Table 1: California Natural Gas Use (BCF/day)**

| | 2012 | 2016 | 2020 | 2020 Change From Case 1 |
|---|---|---|---|---|
| Case 1 Reference Case RPS | 2.36 | 2.57 | 2.88 | |
| Case 2 High Solar | 2.34 | 2.45 | 2.52 | -12% |
| Case 3 High Wind | 2.34 | 2.48 | 2.60 | -10% |

Source: Energy Commission, Electricity Analysis Office

Results from this study are indicative but are limited both by the assumptions used and the fact that the model staff used does not incorporate integrated local area functions and ramping constraints. Its findings would need to be tested with more sensitivities and with other models.

Study results indicate that at least three areas deserve further research because the assumptions made in this study have a major impact on the type of proxy generation needed to firm and back-up intermittent renewables. First, alternative levels of combined heat and power should be tested, since the addition of so much baseload power in-state and in Southern California may be difficult to achieve with existing emission credit problems and the lack of a mechanism to make it happen. Second, alternative assumptions about compliance with once-through cooling mitigation requirements should be tested because the interactions of all the Scoping Plan programs lead to unrealistic capacity factors in the replacement of once-through cooling combined cycles by 2020. Third, there are possible instances of over-generation, a condition when more generation is provided than load is available to consume it; staff observed some over-generation situations but did not have time to explore this issue. Staff proposes to take a closer look at all three of these issues in follow-up work.

## Study Purpose

As part of the directions on assessing the role of natural gas in implementing the 33 percent renewables goal, the *2009 IEPR* Scoping Order directs analysis to:

> Assess the interaction of renewable and conventional resources, including the amount, location and performance characteristics of new fossil-fired generation that may be needed to firm up increased levels of renewables.[1]

Natural gas is the marginal fuel in California's electricity system, serving energy, capacity, and ancillary service needs. According to a recent study prepared by MRW and Associates, natural gas use in the future will be driven more by five expanding ancillary service roles: intermittent generation support, local capacity requirements, grid operations support, extreme load and system support, and general energy support.[2] The need for these larger ancillary service functions is driven in part by the addition of greater amounts of intermittent resources and the lack of suitable electricity storage technologies. These ancillary service requirements suggest that additional levels of natural gas units might be needed by 2020 above what would be required to serve load and peak capacity. Conversely, other policies seek to reduce natural gas use. The California Air Resources Board's AB 32 *Climate Change Scoping Plan*. (Scoping Plan) proposes that high levels of new energy efficiency (EE), combined heat and power (CHP) and rooftop photovoltaic (PV) units should be used to reduce grid-supplied load. The policy to reduce use of once-through cooling (OTC) technologies will occasion a shift in the natural gas generation now served by these coastal units. This study identifies the range of need and type of units that may be required through 2020 in the context of those goals.

This tightly focused study is one of a suite of analyses being done by the California Energy Commission (Energy Commission), the California Public Utilities Commission (CPUC), utilities, and the California Independent System Operator (California ISO) to further integration of more renewables into the grid serving California. Staff focused on the factors that would drive the need for new natural gas units assuming the very large demand reductions anticipated in the Scoping Plan. The study also incorporates policies to replace or repower older gas-fired units that use once-through cooling, since this will be a necessary portion of generation development during the next decade. Within these constraints, the study examines whether the type of intermittent renewable added has a significant impact on the location and amount of incremental natural gas generation to serve local area and inertia requirements of the system.

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[1] California Energy Commission, http://www.energy.ca.gov/2009_energypolicy/notices/2009-01-09_SCOPING_ORDER.PDF, January 9, 2009, page 3.

[2] MRW & Associates, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, May 2009, Chapter 4, CEC-700-2009-009, http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF.

Other studies will be necessary to add a full look at natural gas generation needs because the tools available for this project cannot model the minute-by-minute and intra-hour ramping variability of the overall system to match fluctuations in loads and generation. The California ISO is expected to examine ramping in its upcoming study on integrating high levels of renewables. Studies addressing related issues include an Energy Commission consultant study that examines the impact of high levels of renewables on gas pipeline and storage systems,[3] and a CPUC study that is examining varying renewable build-outs coupled with transmission options and cost estimates.[4]

This study postulated that adding high levels of intermittent renewables would affect the functions of natural gas generation. The California natural gas fleet currently provides approximately 100,000 GWh to 110,000 GWh of energy each year. It was built to provide dispatchable, reliable power and to serve as the back-up resource during periods of low hydroelectric availability. Typically, the amount and variation in natural gas use is driven by variations in retail sales—whether from business cycles or weather-related demands—and from swings in the availability of hydropower. These traditional drivers will be affected by how much incremental energy efficiency savings reduce load growth. EE levels affect not only overall load growth, but also the amount of renewables that must be added to achieve 33 percent of retail sales, thus making energy efficiency achievement a central uncertainty in the demand for natural gas.

## Study Design

This study addresses the range and type of natural gas generation in California and the rest of the Western Electricity Coordinating Council (WECC) that will be needed in 2012, 2016, and 2020 to support 33 percent renewables. Also assumed are the demand-reducing strategies of the AB 32 Scoping Plan and the State Water Resource Control Board's (SWRCB) possible policy of reducing once-through cooling, which will result in substantial changes in the current fleet of once-through cooling units.

Which renewable technologies will emerge over the next dozen years is uncertain and depends on multiple policy, financing, and siting considerations. Since solar thermal and wind generation have different performance profiles[5] and California locations,[6] the study

[3] ICF, *Impact of Variations in Renewable Generation on California's Natural Gas Infrastructure*, CEC-500-02-004.

[4] E3 and Aspen, 33% RPS Implementation Analysis Presentations, January 2009.

[5] MRW & Associates, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, May 2009, Chapter 4, CEC-700-2009-009, http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF.

[6] See Appendix A.

investigated whether the emergence of either as the dominant resource would imply different natural gas support to keep the system reliable. If different support is needed, then the type of natural gas unit to be built would require greater scrutiny. The study also examined whether the preferred location of supporting natural gas units would change. The study does not postulate that these are the most likely cases; instead it explores what information could be gleaned about the minimum amount of new natural gas use that might be necessary.

Even a tightly focused study such as this one requires many assumptions and analytic steps. In broad terms, staff first constructed an updated representation of the current generation and committed resource plans throughout the western inter-connection. This was updated with an improvement of wind profiles for each region of the West. Because state policy to reduce generation that uses OTC is established, staff built-in a sample replacement approach for each natural gas-fired OTC plant. Then various renewable build-outs could be tested. If additional natural gas units were needed to meet system, local reliability, or inertia needs, this was done.

The measurements used to determine the amount of gas and type of gas unit needed are generation additions needed to "back-up" this level of renewables and the amount needed to replace OTC. These are compared among the cases to determine the range of uncertainty and whether staff can identify zonal areas where the natural gas supply constraints might be more problematic.

The study does not pick a preferred case or deal with natural gas needs associated with local area reliability (LAR) concerns and ramping/ancillary services back-up. It does not examine Renewables Portfolio Standard (RPS) non-performance or alternative OTC replacement requirements and patterns.

# Key Assumptions and Case Designs

## *Common Load and Generation Assumptions*

**Table 2** summarizes the key input assumptions used in this study, and **Table 3** summarizes the three cases. Year-by-year detailed assumptions and additional documentation can be found in **Appendix 2**.

Some of the key assumptions and constraints are:

- Since the load forecast used in this study came from the *2007 IEPR*, demand forecasts are not adjusted to account for the post-2007 economic downturn or projected recovery patterns and may overstate demand.
- The generation in the rest of the WECC was revised to incorporate the many RPS requirements of individual states. Throughout the West, an emphasis on renewables has decreased plans for new fossil-fired generation.

### Table 2: Key Drivers, Working Assumptions, and 2020 Values

| Key Driver - Signal | Working Assumption / Approach |
|---|---|
| Net Energy For Load and Peak Demand Forecast – California (2020) | CEC Final IEPR 07 demand forecast updated per LTTP decisions. Includes some embedded energy efficiency, solar PV, and CHP/DG - 341,755 GWh. 71,425 MW |
| Retail Sales Forecast (2020) | CEC Final IEPR 07 demand forecast updated per LTTP decisions. Includes some embedded energy efficiency, solar PV, and CHP/DG excludes CDWR,WAPA MWD sales 308,070 GWh |
| Load Forecasts – rest of WECC | Ventyx Spring 2008 Reference Case |
| Load shape | CEC's algorithm based on 5 years of historic hourly load data |
| Incremental Energy Efficiency – CA | Case 1 contains only EE embedded in updated IEPR07 demand forecast. Case 2 and Case 3 include goals specified in the Scoping Plan |
| Incremental CHP/DG self-generation | Case 1 contains only DG Self-Gen embedded in updated IEPR07 demand forecast. Case 2 and Case 3 include goals specified in the Scoping Plan |
| Renewables – existing (as of 12/2008) | As of 12/2008 32,489 GWh (29,780 In CA and 2,689 Outside CA) |
| Renewables – net short (2020) | Case 1 = 29,145 GWh<br>Case 2 and Case 3 = 45,482 GWh factoring Scoping Plan goals for EE, PV and CHP/DG. |
| Wind and solar shapes | Wind shapes – CEC's load shaping algorithm based on 3 years of meso-scale wind generation. Consistent with load shape algorithm. CSP shape based on NREL |
| Tradable RECs (2020) | Case 1 – 5,014 GWh<br>Case 2 – 4,089 GWh<br>Case 3 – 14,370 GWh |
| Existing generation in CA | 60,329 MW Fall 2009 |
| Existing generation out of CA | Ventyx Spring 2008 Reference Case |
| OTC generation retirements/replacements | 12,655 MW retired /7,758 MW repowered/replaced by 2020 |
| Expiration of CA coal contracts | Reid Gardner 4 (out 1/1/2014) and Navajo 1,2, and 3 (out 1/1/2019) |
| Natural Gas Price (and other fuel prices) | Ventyx Spring 2008 Reference Case Fuel Prices |
| Planning reserve margins | Annually - 15% by control area WECC-wide |
| Long-Line Transmission from California to distant renewable resources (e.g. WY, BC, MT, NM) | New lines between BC and Northern California and Baja and Southern California in Case 2 High Wind |

Source: Energy Commission staff, Ventyx and AB 32 Scoping Plan

- The characterizations of EE, CHP, and rooftop PV were developed to achieve the AB 32 Scoping Plan targets. While they are based on the best information staff had, they are not derived from firm program plans or tested for cost-effectiveness.
- Staff had to create a compliance path for implementing OTC policy. Based on best available information, the plan relies heavily on combined cycles rather than combustion turbines.

In addition to the OTC replacement generation, which is discussed later, three areas of the state required additional new natural gas units to keep the control area loads and resources in balance. Between now and 2020, 1,510 MW of combined cycles and 400 MW of combustion turbines were added to the SMUD, Turlock Irrigation District, and Imperial Valley Irrigation District control areas. The choice between combined cycles and combustion turbines hinged on the relative amounts of energy needed and the announced construction or acquisition intentions of these publicly owned utilities. These units play a supporting role in integrating intermittent renewables into the system.

### *Renewable Resources—Three California RPS Case Descriptions*

A key focus of this study was to examine the functions and sources of natural gas-fired generation that would be needed to achieve the 33 percent renewable energy goal. Staff developed three cases, one to provide a 20 percent RPS case and two "bookend" estimates of the potential changes this level of renewable energy may impose on the timing and use of gas for electricity generation in California. Staff also developed a constant build-out of new renewables throughout the rest of the West in recognition of the many states that have implemented renewable performance standards.

As shown in **Appendix 1 Table 1-1**, there are three cases: the first is the 20 percent RPS Reference case, assuming the AB 32 Scoping Plan goals are not met; the other two bookend cases meet the AB 32 Scoping Plan goals for EE, CHP, rooftop PV, and 33 percent RPS. The bookend cases tested high penetrations of either wind (Case 3) or solar (Case 2) because these have substantially different impacts on the way natural gas-fired generation would need to operate to maintain system reliability.

The 20 percent case included projects with investor-owned utility or publicly owned utility contracts expected to come on-line by 2019 and also added geothermal generation from the Imperial Valley. Including existing renewables, the renewable mix for the Reference case is about 40 percent geothermal, 9 percent solar, and 27 percent wind; while small hydroelectric (hydro) and biomass/biogas provide 24 percent of the energy. The High Wind case reduces the amount of geothermal generation from the Reference case and adds wind generation to achieve 33 percent by 2020. The renewable generation mix for the High Wind case is about 24 percent geothermal, 4 percent solar, and 54 percent wind, with the remaining 18 percent met by small hydro and biomass/biogas. The High Solar case reduces the amount of geothermal generation from the reference case and adds solar generation to achieve 33 percent by 2020. The renewable generation mix for the High Solar case is about 24 percent geothermal, 37 percent solar, and 21 percent wind; with the remaining 18 percent from small hydro and biomass/biogas.

All three cases draw on extensive planning work being done in the RETI process, selecting only the most probable and cost-effective projects meeting the selection criteria for each case. The generation added after 2011 for the two 33 percent cases was based on CREZ projects in the High Wind and High Solar cases in the forthcoming RETI Phase 2 Implementation Analysis. For more information on the cases described above, see **Appendix 1: Renewable Energy Case Descriptions**.

## Table 3: Description of Three Cases

| Assumed Conditions | Reference Case | Case 2: High Solar | Case 3: High Wind |
|---|---|---|---|
| SWRCB OTC Policy | Complies (Same NG facility compliance changes in all cases) | Complies (Same NG facility compliance changes in all cases) | Complies (Same NG facility compliance changes in all cases) |
| Underlying Demand Forecast | *IEPR 2007* | *IEPR 2007* | *IEPR 2007* |
| **CARB AB 32 Scoping Plan GHG Emission Abatement Measures (2020 GWh)** | | | |
| Energy Efficiency | Only what is embedded in *IEPR 2007* Demand Forecast | 34,707 | 34,707 |
| Rooftop Photovoltaic | Only what is embedded in *IEPR 2007* Demand Forecast | 4,845 | 4,845 |
| CHP | Only what is embedded in *IEPR 2007* Demand Forecast | 32,304 | 32,304 |
| RPS-obligated Retail sales | 308,069 | 236,213 | 236,213 |
| 2020 Maximum RPS Target | 20% of IEPR 2007 Forecast retail sales 61,800 | 33% of adjusted retail sales 78,000 | 33% of adjusted retail sales 78,000 |
| RPS Resource Mix | Geothermal 24,900<br>Solar 5,800<br>Wind 16,800<br>Other 14,300 | Geothermal 18,500<br>Solar 28,900<br>Wind 16,300<br>Other 14,300 | Geothermal 18,500<br>Solar 3,300<br>Wind 41,800<br>Other 14,300 |

Source: Energy Commission staff.

# Impact of "Loading Order" Resource Additions

"Loading order" resources are the preferred resource additions identified by the state's energy agencies through the *Energy Action Plan* process and accepted by the Air Resources Board's Scoping Plan. The "loading order":

> …describes the priority sequence for actions to address increasing energy needs. The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we support clean and efficient fossil-fired generation. Concurrently, the bulk electricity transmission grid and distribution facility infrastructure must be improved to support growing demand centers and the interconnection of new generation, both on the utility and customer side of the meter.[7]

One difference between this study and other current investigations is that it incorporates the full suite of preferred resource priorities contained in the Scoping Plan. Building out resource plans that contained the energy goals for EE, rooftop PV, and CHP had several important impacts on the outcome of this study. As detailed below, it significantly reduced the total amount of grid-connected renewables that need to be added to reach 33 percent of retail sales. Second, it changed the load shape of the remaining load. Third, it replaced some existing dispatchable natural gas generation with combined heat and power generation.

## *Impacts of Demand-Reducing Complementary Resource Goals*

The impact of adding the Scoping Plan resource targets on the forecast of retail sales and the calculation of the amount of incremental renewables needed to meet a 33 percent goal by 2020 is shown in **Table 4.**

The Scoping Plan loading order resources of EE, CHP, rooftop PV, and 33 percent RPS contribute 117,337 GWh of reduced demand or generation by 2020. Of that amount, 61 percent comes from the complementary programs of EE, CHP and rooftop PV. Incremental EE accounts for 30 percent, CHP for 28 percent, and the rooftop PV for 4 percent. Incremental renewables are counted on for 39 percent of the preferred resource additions. In total, the complementary programs dependable capacity in 2020, result in savings at the time of system peak of up to 15 percent.

[7] California Public Utilities Commission and California Energy Commission, *Energy Action Plan II,* September 2005, http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

**Table 4: Impact of AB 32 Complementary Policies on Derivation of Incremental Renewables Needed in 2020 (GWh)**

| | | 2020 GWh |
|---|---|---|
| 1 | Statewide Net Energy for Load (Used in Production Cost Modeling) | 341,755 |
| 2 | Statewide Losses | 21,387 |
| 3 | LSE Statewide Retail Sales (line 1 – line 2) | 320,368 |
| 4 | Non-RPS Deliveries (CDWR, WAPA and MWD) | 12,299 |
| 5 | Adjusted Retail Sales for RPS Calculation (line 3 – line 4) | 308,069 |
| 6 | AB 32 EE Beyond Amount in Energy Commission Forecast | 34,707 |
| 7 | AB 32 CHP Beyond Amount in Energy Commission Forecast | 32,304 |
| 8 | AB 32 Rooftop PV Beyond Amount in Energy Commission Forecast | 4,845 |
| 9 | Adjusted Retail Sales for 33% AB 32 RPS Calculation (line 5 – 6,7,8) | 236,213 |
| 10 | Renewable Energy Needed for 33% (33% of Line 9) | 77,950 |
| 11 | Existing Renewable Energy as of 12/31/2008 | 32,469 |
| 12 | 33% Renewable Net Short (Cases 2 and 3 (line 10- Line11)) | 45,481 |

Source: Energy Commission staff, compiled from California Energy Demand 2008–2018 Staff Revised Forecast CEC-200-2007-015SF. Forecast extended to 2020 by Energy Commission staff. The actual rooftop PV, EE and CHP impacts in AB 32 Scoping Plan for 2020 are 4,500, 32,000 and 30,000 GWh, respectively. To these estimates the ARB Scoping Plan adds an amount to account for transmission line losses. Existing renewables based on 2008 production cost model simulation results (29,780 GWh) and eligible renewable generation for regions outside California (2,689 GWh).

## *Impacts of Incremental Combined Heat and Power*

The Scoping Plan contains a goal of increasing CHP in the state by 32,000 GWh in 2020. This goal is one of the major assumptions in this study and a key driver of results. To translate that goal into specific units, staff started with a 2005 Public Interest Energy Research collaborative report[8] that assessed CHP technical and market potential for industrial CHP facilities in California. Recently, ICF International, a consultant that participated in the 2005 assessment, updated some of the major drivers and provided a forecast for this study. The updated assumptions include natural gas prices, cost, and performance of CHP technology, and wholesale electricity prices. However, even with these updates, the quantities of CHP fell short of the Scoping Plan goal of 32,000 GWh. To reach this goal, Energy Commission staff assumed that growth remains proportional in each region. For example, if 30 percent of new CHP was in *Region A*, then 30 percent of the goal was assumed to be in *Region A*. Each CHP generator is modeled as using natural gas and having a full load higher heating value

[8] *Assessment of California Combined Heat and Power Market and Policy Options for Increased Penetration*, PIER Collaborative Report, November 2005, CEC-500-2005-173, http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

(HHV) heat rate of between 5,600 British thermal units/kilowatt hours (Btu/KWh) and 6,200 Btu/KWh, depending on size of CHP generator and their process. Lack of an independent technical assessment of ways to achieve the CHP goal subjects this assumption to a great deal of uncertainty.

ICF International provided assumptions on the amount of CHP host sites available by utility. The Scoping Plans goal called for approximately 32,000 GWh of CHP, which equates to about 4,700 MW of installed capacity. To site this much CHP, staff had to add 2,585 MW of new generation in Southern California (See **Table 5**). Although most host sites are in Southern California, siting this level of gas-fired CHP might be difficult in light of the scarcity of emission credits for the relevant air districts.

**Table 5** presents the simulation results for adding CHP in the High Solar case; results for the High Wind case are nearly identical. CHP expands to use one-quarter of all natural gas used for generation by 2020. This is because all new CHP is assumed to have a must-take contract. When there is excess generation, other dispatchable natural gas units are backed down. **Figure 1** emphasizes this point. As the amount of CHP (and EE) increases in Case 2 and Case 3, the amount of dispatchable natural gas generation decreases when compared to the Reference case (no additional CHP or EE).

**Table 5: New CHP and California Natural Gas Use in 2020—Case 2 High Solar**

| Region | Installed New CHP (MW) | New CHP Fuel Use (GBtu) | New CHP Generation (GWh) | All Natural Gas Fuel Use (GBtu) | All Natural Gas Generation (GWh) | Percent of CHP to Total NG Fuel Use | Percent of CHP to Total NG Generation |
|---|---|---|---|---|---|---|---|
| LADWP | 195 | 7,538 | 1,313 | 78,334 | 10,042 | 10% | 13% |
| Northern CA | 1,750 | 70,495 | 11,532 | 349,923 | 42,835 | 20% | 27% |
| San Diego | 319 | 12,191 | 2,067 | 78,775 | 10,830 | 17% | 21% |
| SMUD | 75 | 3,261 | 542 | 70,080 | 9,818 | 5% | 6% |
| Southern CA | 2,390 | 95,919 | 16,041 | 371,740 | 48,629 | 26% | 33% |
| Combined Total | 4,730 | 189,404 | 31,495 | 948,852 | 122,155 | 20% | 26% |

Source: Energy Commission, Electricity Analysis Office

These programs also changed the shape of the load to be served by renewable resources. The EE and rooftop PV load shapes used in this analysis are those used in the *2007 IEPR Scenarios Analysis*. Nearly 80 percent of the energy efficiency savings are from lighting and refrigeration measures. These measures result in average load shapes that mimic baseload as well, with capacity factors in the 54 to 68 percent range. EE programs contribute more to peak reduction in Southern California than in Northern California. While refrigeration and lighting are dominant, air conditioning reductions play a bigger role in Southern California. There is roughly twice as much air conditioning in the Southern California Edison (SCE) mix of measures as the Pacific Gas and Electric (PG&E) mix, and nearly three times as much air conditioning in the SCE mix as in the San Diego Gas & Electric (SDG&E) mix. Thus, EE savings both reduced total load and flattened the peak in Southern California. Reducing the peak complements intermittent resources, which perform best in the mid-range and off-peak periods.

The load shape for the rooftop PV profiles also came from the *2007 IEPR Scenarios Analysis* and ranged from 19 percent to 21 percent capacity factor depending on the building's service area's location.

The combined effects of energy efficiency and CHP have a marked effect on use of dispatchable natural gas**.** This is illustrated in **Figure 1** on the following page by the way the bottom part of the stack shrinks when new CHP and energy efficiency resources are added. These complementary programs have a major impact on natural gas use and the type of gas-fired generation used even before intermittent renewables are added.

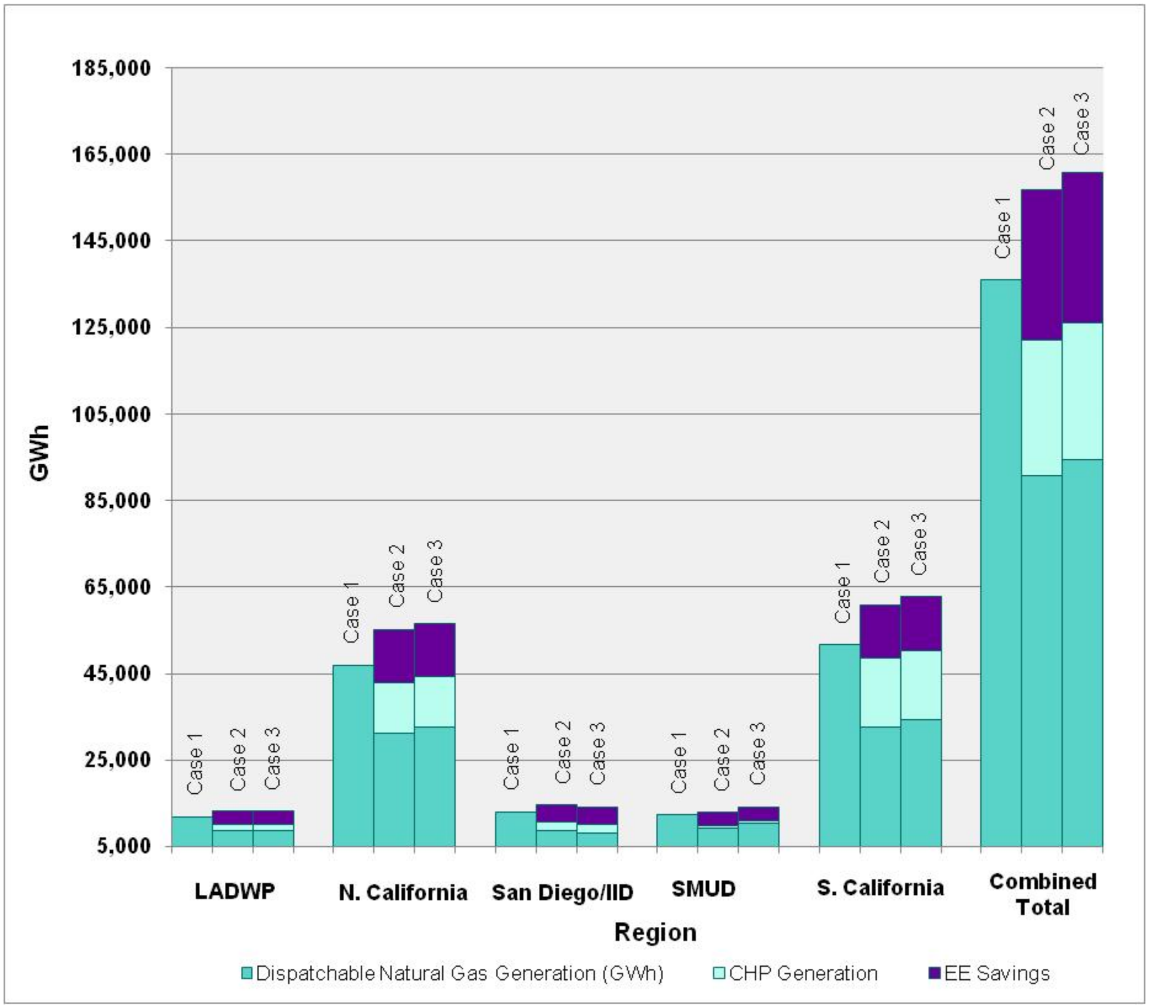
## Impact of Modifying Once-Through Cooling Generation

This study incorporated impending changes from new water policies on existing gas-fired generation. SWRCB policies designed to reduce the adverse impacts of power cooling technologies on coastal and estuarine waters will have a major impact on the existing natural gas-fired generation that uses OTC.[9] The generators have three options:

- To replace its cooling systems with methods which do not use OTC.
- Be replaced with new units that do not use OTC.
- If transmission upgrades allow, replace this capacity elsewhere.

[9]State Water Resources Control Board Scoping Document: *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plan Cooling*, March 2008, http://www.waterboards.ca.gov/plans_policies/docs/coastal_estuarine/scope_doc031808.pdf

**Figure 1: Effect of Additional EE and CHP on Dispatchable Natural Gas 2020**




Source: Energy Commission, Electricity Analysis Office

To incorporate the possible impacts of these policies on natural gas use and renewable energy integration, the study draws on the extensive work being done by an inter-agency working group developing an integrated plan to achieve OTC mitigation while assuring system reliability.[10] The units considered are shown in **Figure 2**. Most of the units are contained within four LARs where the units provide local capacity and inertia as well as general system capacity and ancillary services. These plants must be dealt with while considering the impacts their potential closure would have on electricity system operation.

[10] See materials prepared for the May 11, 2009, Integrated Energy Policy Report Committee workshop on Options for Maintaining Electricity system Reliability When Eliminating Once-Through Cooling Plants, http://www.energy.ca.gov/2009_energypolicy/documents/index.html#051109

## Figure 2: Once-Through Cooling Units and Local Reliability Areas


Source: Energy Commission cartography staff. Humboldt, excluded since it is assumed to be replaced prior to the simulation period beginning 2012. Diablo Canyon and San Onofre are excluded since their replacement dates fall outside of the simulation ending 2020.

Plans for specific units have not been developed by the inter-agency team supporting the SWRCB. The agencies have proposed a general approach and replacement timetables for each set of units. Staff used this information and other available information to create a compliance path. Other compliance paths are plausible. The initial step in this analysis consisted of developing assumptions for the retirement, repowering, or replacement of the plants in California known to use ocean water in their cooling systems. The assumptions are for the study years 2012, 2016, and 2020. These assumptions remain constant in all three cases and use the following as guidance:

- The California ISO's *2010 Local Capacity Technical Analysis—Report and Study Results.*
- Inertia[11] assumptions from the *2007 IEPR Scenarios Analysis* that address system operation under the Southern California Import Transmission nomogram.
- High probability transmission upgrades
- Where available, resource plan filings

By 2020, the units at Encina and South Bay located in the San Diego Local Reliability Area (LRA) were replaced with a combination of combined cycles and transmission upgrades. By 2020, the Bay Area LRA OTC units at Potrero, Contra Costa, and Pittsburg were retired and replaced with transmission upgrades to meet the Bay Area LCR requirements. By 2020, the units at Morro Bay, which are not in an LCR area, were assumed retired and not replaced. The units at Moss Landing, with the exception of units 1 and 2, which were recently repowered, were retired and assumed to be replaced by combined cycles. By 2020, the units at Mandalay and Ormond Beach in the Big Creek/Ventura LRA area were retired and not replaced with new generation. Transmission infrastructure improvements are assumed to be in place, and, even with the retirement of these units, the LRA capacity requirements are still satisfied, if only barely. By 2020, all OTC units in the Los Angeles Basin LRA area, with the exception of Huntington Beach 3 and 4, which were recently repowered, are retired and replaced with a combination of combustion turbines and combined cycles in the area to meet the LRA capacity and inertia requirements. **Table 6** provides these details in aggregate while **Appendix 2** provides OTC unit by unit assumptions.

These modifications had a significant impact on the types and amount of natural gas added to support increased levels of renewables. With so much efficient new generation added in the 20 percent case, additional incremental gas-fired generation was not needed to meet a 15 percent control area reserve margin. Instead, these OTC replacement units provided both

[11] In an electric power system, turbines provide mechanical power to the generator which converts mechanical power to electrical power to feed the loads in the system through the transmission and distribution lines. When there is a disturbance in the system or the loads fluctuate, the generators' outputs adjusts. Inertia, available from the turbo-generators in a system, is vital for the system to remain stable and supply stable power and frequency to the load centers with adequate, steady voltage.

the energy and capacity needed by the year 2020. When 33 percent renewables were added, for both the wind and solar cases, the energy produced by these OTC units dropped sharply and capacity factors plunged from roughly 60 percent to less than 20 percent. The results were similar in both Northern California and Southern California. Case 3 High Wind case did result in slightly higher gas use than Case 2 High Solar in both Northern and Southern California (see **Table 7**). By 2020, depending on the case, between 11 and 23 percent of natural gas-fired generation in California is consumed by power plants associated with the OTC issue (see **Table 8)**.

### Table 6: Once-Through Cooling Assumptions in All Cases

| | Dependable MW | Percent in Northern California | Percent in Southern California |
|---|---|---|---|
| Current OTC capacity considered in this study by 2020[a] | 15,069 | 31% | 69% |
| OTC capacity retained— reclaimed water will replace OTC at existing site | 964 | | 100% |
| Former OTC capacity recently repowered | 1,450 | 70% | 30% |
| OTC retained—assumed transmission fix | 3,813 | 22% | 78% |
| OTC capacity assumed retired in this study by 2020 | 12,655 | 29% | 71% |
| OTC total replacements by 2020 | 7,758 | 19% | 81% |
| 13% amount assumed to be replaced by simple cycle and contributes to LCR | 1,000 | | 100% |
| 87% of combined cycle OTC assumed replaced for LCR and inertia constraints | 6,758 | 22% | 78% |

Source: Energy Commission, Electricity Analysis Office

[1] Humboldt is assumed replaced prior to 2012. The nuclear units replacement assumptions are beyond the last year simulated, 2020

### Table 7: Once-Through Cooling Replacement Generation Annual Average Capacity Factors in 2020

| 2020 | Case 1: Reference | Case 2: High Solar | Case 3: High Wind |
|---|---|---|---|
| OTC Replacement Combined Cycle Average Capacity Factors in Northern California | 61% | 20% | 23% |
| OTC Replacement Combined Cycle Average Capacity Factors in Southern California | 56% | 22% | 25% |
| OTC Replacement Simple Cycle Average Capacity Factors in Southern California | 17% | 15% | 15% |

Source: Energy Commission, Electricity Analysis Office

**Table 8: Once-Through Cooling Replacement Generation Fuel Use Compared to Statewide Natural Gas Fuel in 2020**

| | Reference Case | High Solar | High Wind |
|---|---|---|---|
| 2020 | Gbtu | Gbtu | Gbtu |
| Total Natural Gas Use For All California Generation | 1,082,378 | 948,852 | 978,231 |
| 2020 | Gbtu | Gbtu | Gbtu |
| OTC Replacement Fuel Use in Northern California | 52,155 | 18,113 | 20,526 |
| OTC Replacement Fuel Use in Southern California | 191,892 | 84,428 | 94,916 |
| | | | |
| Total OTC Fuel Use Compared to Statewide Fuel Use | 23% | 11% | 12% |

Source: Energy Commission, Electricity Analysis Office

Combined cycles are added instead of combustion turbines based on rules of thumb about system inertia and necessary system support. The implications of the reduced capacity factors indicate that more attention should be paid in future investigations to the attributes of needed generation.

These reduced capacity factors for the OTC units by 2020 indicate there may be a disconnect between the timelines for OTC replacement on a schedule driven by water policy requirements and the planned build-out of energy efficiency and renewable resources driven by energy and climate polices.

Not only do Case 2 and Case 3 contain larger amounts of renewables than Case 1, these cases also have higher levels of energy efficiency, rooftop photovoltaic (PV) and CHP. Based on this and other studies of OTC replacement plans, there could be significant benefits from matching retirements with the development schedule for such preferred resources.

## Wind, Solar, and Energy Efficiency Performance Profile Findings

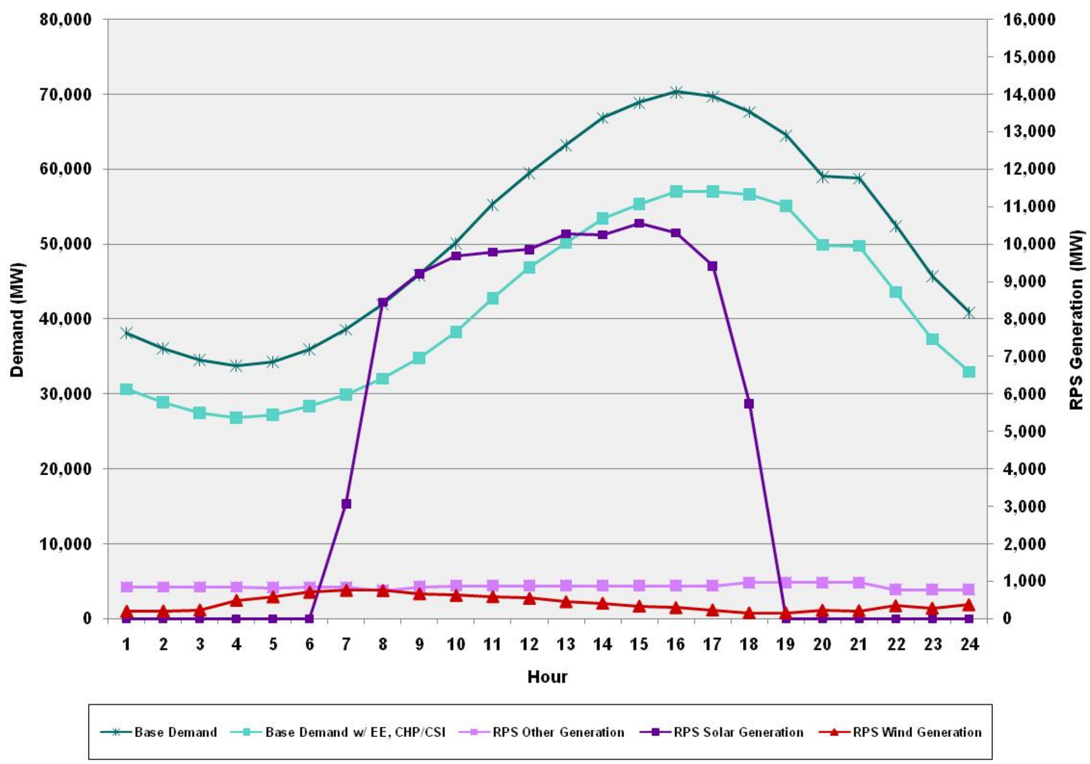
In California, wind energy is usually highest during off-peak hours, so a High Wind energy mix is likely to require changes in the timing and amount of natural gas for electricity generation compared to a renewable energy mix with high levels of solar. A High Solar mix is likely to have a large proportion of generation coinciding with peak hours,[12] though not with the absolute peak hour

[12] MRW & Associates, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, May 2009, Chapter 4, CEC-700-2009-009, http://www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF.

Hourly generation for peak days are illustrated **Figure 3**. As this figure shows, solar ramps up in the morning, gently peaks in the early afternoon, and starts to decrease by the time of system peak in the later afternoon.

**Figure 3** compares wind, solar and other renewable profiles to peak day demand profiles. The peak day demand profile is shown with and without Scoping Plan complementary programs.

**Figure 3: California Sample Peak Day Output of Wind and Solar Compared to Load — High Solar Case**

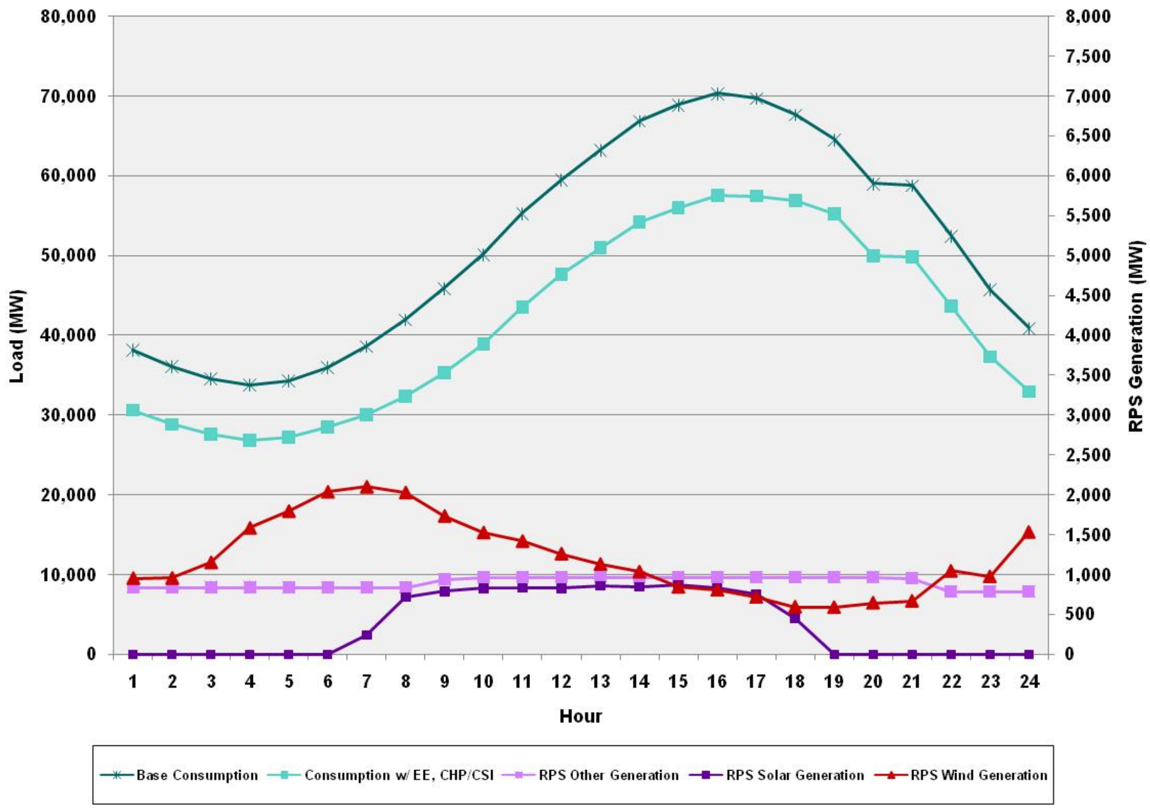



Source: Energy Commission, Electricity Analysis Office staff

Note: This graph uses two scales, one for load and one for renewable generation. Readers should not compare the amount of renewables with the amount of load. The purpose of the graph is to illustrate hourly profiles, not amount of output.

In the High Wind sample day, shown in **Figure 4**, the aggregate wind profile moves counter to the load profile. This case does have a flatter total renewables profile than the High Solar case.

**Figure 4: California Sample Peak Day Output of Wind and Solar Compared to Load — High Wind Case**



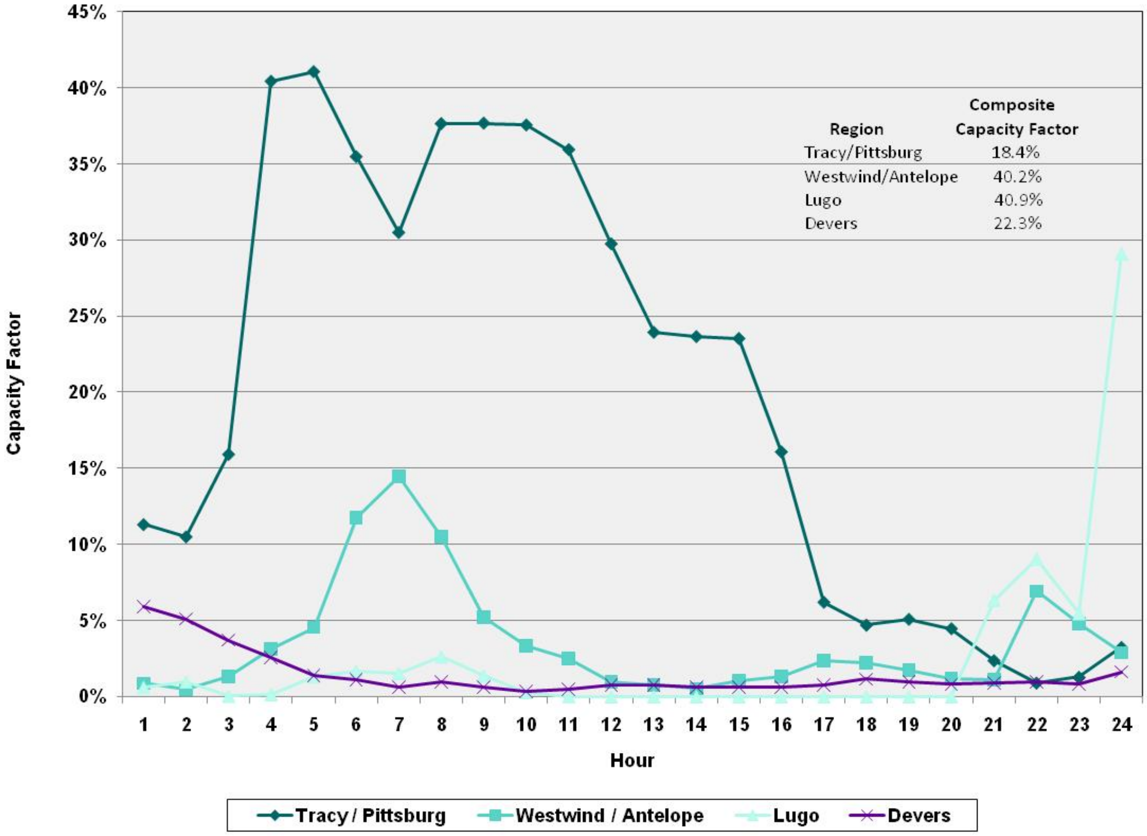

Source: Energy Commission, Electricity Analysis Office staff

Note: This graph uses two scales, one for load and one for renewable generation.

To model intermittency more accurately, staff developed regionally consistent output profiles for wind throughout the WECC. This was based on time series data for wind generation in the West done by the National Renewable Energy Laboratory (NREL).[13] The NREL Mesoscale historic hourly wind profiles provided a valuable basis from which to create generalized hourly wind profiles for regions in the West. Details of the Energy Commission's algorithm to create these hourly profiles can be found in **Appendix 2**, under Energy Commission Approach to Developing Wind Shapes. The California annual capacity factors and peak day hourly profiles for wind generation used in this study are shown in **Figure 5**.

[13] The NREL Mesoscale historic simulated hourly wind generation for 2004-2006 was obtained by the Energy Commission courtesy of Michael Milligan with NREL's National Wind Technology Center: http://www.nrel.gov/wind/systemsintegration/pdfs/2008/lew_creating_dataset_wwsis.pdf

**Figure 5: California Peak Day Hourly Wind Profiles**




Source: Energy Commission Electricity Analysis Office Staff

These regional shapes show how important it is to designate the location of the wind resource in modeling its hourly output and capacity factor. Wind from two of the resource areas had capacity factors of 40 percent, while two others had capacity factors half of that. Such different performance profiles would cause significantly different impacts on the need for system support to be provided by natural gas units.

## Natural Gas Findings

Achieving the Scoping Plan complementary policies and the OTC replacement policies significantly reduced both the need for new proxy natural gas resources and also reduced the generation from the existing fleet of dispatchable natural gas resources in both the High Wind and High Solar cases. There is a 15 percent WECC-wide decrease in both bookend cases in natural gas use compared to staff's reference case by 2020 as shown in **Table 9**. The majority of gas reductions came from out-of-state natural gas units, with a 10 to 12 percent drop in in-state gas use and a 18 to 19 percent drop in out-of-state natural gas use for electric generation (see **Table 9)**.

**Table 9: Impact of High Solar and High Wind Case on Natural Gas Use Compared to the Reference Case**

| 2020 | Gbtu | Gbtu Change | Percentage Change From Case 1 |
|---|---|---|---|
| California | | | |
| Case 1 Reference Case | 1,082,378 | | |
| Case 2 High Solar | 948,852 | (133,526) | 12% |
| Case 3 High Wind | 978,231 | (104,147) | 10% |
| Rest of West | | | |
| Case 1 Reference Case | 1,187,104 | | |
| Case 2 High Solar | 974,968 | (212,136) | 18% |
| Case 3 High Wind | 958,071 | (229,033) | 19% |
| WECC Total | | | |
| Case 1 Reference Case | 2,269,481 | | |
| Case 2 High Solar | 1,923,820 | (345,661) | 15% |
| Case 3 High Wind | 1,936,301 | (333,180) | 15% |

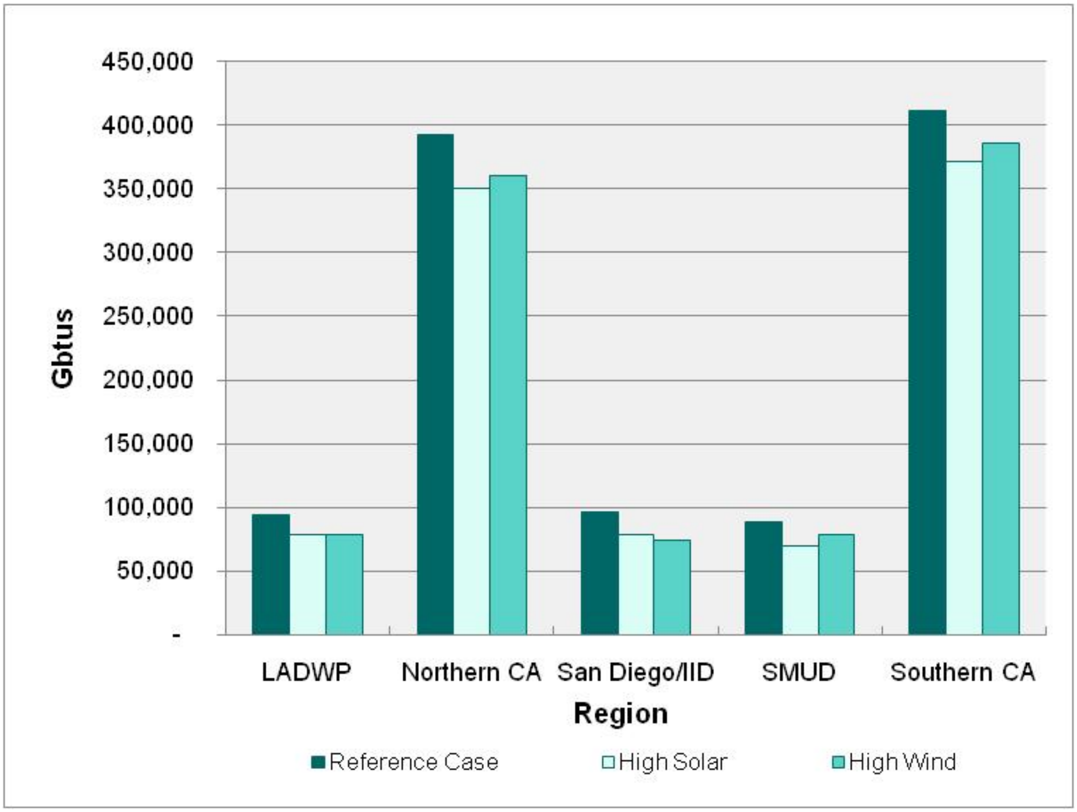
Source: Energy Commission, Electricity Analysis office

In all cases, some incremental new natural gas units were needed to meet local capacity deficits. The SMUD, Turlock Irrigation District, and Imperial Valley Irrigation District's all had capacity deficits to meet a planning reserve margin of 15 percent. The total proxy capacity added was 1,900 MW by 2020 to meet this 15 percent criteria. In cases where the capacity deficit was large enough to include energy needs, combined cycles were added. In the remaining cases, combustion turbines were added to balance the system. Beyond these additions and those occasioned by OTC replacements, no new natural gas units were needed in California in all three cases.

While both High Solar and High Wind cases caused a 15 percent decline in overall natural gas use, more in-state gas was needed for the High Wind cases compared to the High Solar case. This is consistent with the wind profile having greater intermittency and a performance profile less coincident with load patterns (as shown in **Figure 6**).These findings are indicative and need to be followed up by studies that examine other system characteristics, such as intra-hour ramping, that are not measured by a production cost model.

As load was held roughly constant over the period by complementary programs and incremental generation was filled by new renewables and OTC replacements, total natural gas consumption rose slightly in Case 2 (High Solar) and Case 3 (High Wind) as large amounts of combined heat and power, all fueled by natural gas, were added to the system, as shown in **Figure 6.**

**Figure 6: 2020 California Natural Gas Use for Electric Generation**




Source: Energy Commission, Electricity Analysis office

## Possible Impact of Key Uncertainties on Findings

Resource plans are subject to significant economic and regulatory uncertainties. Many different electricity attributes such as energy, peak capacity, ancillary services, preferred resource additions, criteria air limits, GHG impacts, water policies, local area requirements, siting and transmission concerns must be balanced in a resource plan that many input assumptions, analysis approaches, and appropriateness of available tools to answer the questions can impact the viability of the study findings.

The largest potential uncertainty is what future energy demand will be. The study uses a single point load forecast done in 2007 that did not take the current national economic downturn into account. Energy Commission staff's  preliminary demand forecast for the *2009 IEPR* indicates that projected 2020 load may have decreased as much as 9.8 percent statewide.[14] A drop of more than 20,000 GWh demand would change the timing of new resource additions.

The two AB 32 resource cases incorporate aggressive goals for both complementary programs and renewable resource build-outs that will need compliance paths including financing and siting solutions. If the energy efficiency targets are not met, then demand will be higher, more renewables will be needed to achieve a 33 percent resource share, and the impacts on natural gas use might increase. Both the CPUC and the Energy Commission are conducting public processes assessing whether current demand forecasts incorporate some of potential energy efficiency savings and whether programs can be designed to achieve all cost-effective energy efficiency. These investigations should reduce the amount of forecast uncertainty of achieving energy efficiency targets.

Like energy efficiency, CHP targets can be met only if effective program development and pricing policies are identified and enacted. The AB 32 targets are high compared to current program accomplishments, so there is greater uncertainty about reaching the target than exceeding it. The energy agencies are initiating efforts to develop effective programs for both large and small CHP, but until those investigations are complete, the certainty of achieving the CHP target cannot be assured.

Replacement of the OTC units will require careful coordination among many agencies, utilities, and independent generators to stage in a manner that maintains reliability while reaching state water policy goals. One of the findings of this study was that the mix of combined cycles and combustion turbines that were used as a sample OTC compliance path did not make efficient long-term use of the combined cycles. The uncertainty of whether OTC plan development will address the integrated impacts of all of the AB 32 policies will have a direct impact on whether other types of new natural gas are useful to provide back-up generation for intermittent generation.

The study did not test a "cross-over" point at which units added to meet local capacity needs are no longer sufficient to serve the energy load following needs of intermittent renewables.

Another integration problem which could change the relative attractiveness of some resources compared to others is whether and how to back down resources to compensate for off-peak over-generation. Over-generation has been identified in the past as a barrier for expanding off-peak generation. If over-generation exists, then a policy determination needs to be made on which units should be not built or, if built, curtailed. Staff did not pursue a cursory assessment of over-generation for this report because staff intends to address the issue in a more comprehensive study in a 2009/2010 study.

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[14] Chris Kavalec, "Impact of Energy Efficiency Programs on the Preliminary Demand Forecast.", presented at the 2009 IEPR May 21, 2009, workshop.

Studying the interaction of intermittent resources and natural gas units should ideally incorporate ramping and local area reliability directly into the algorithm. Staff's production cost model does not do this, so staff had to supplement the way the model handles local area reliability requirements. The production cost model can capture zonal constraints and deal in part with sub-zonal issues through its bubble topography. But it does not model down to specific local area reliability zones. The analyst must hardwire in assumptions about what is needed to meet local reliability and inertia requirements. One must also assume that today's LAR requirements still hold true from now through 2020.

This model is intermediate between a statewide analysis and a full locational analysis. Whether the method used to incorporate these features into the study are uncertain. Findings on local area impacts are indicative and should be tested further in models such as those used by the California ISO.

The attributes this model cannot address are minute-to-minute variations (ride-through) ramping, fully integrated local area reliability (other than at the zonal level); short-term availability swings due to weather changes such as wind speed or cloud cover, and dispatchability. The model treats CHP as a must-take resource, and this would be problematic if the future programs that incent high levels of CHP do not require must-take features. How this would impact CHP is unknown.

The model is fairly well known, which reduces general uncertainty when a new tool is introduced. Staff believes that the outputs are indicative and directional.

## Conclusions

By adding so many demand-reducing policies and thereby reducing the amount of incremental renewables required to reach 33 percent of retail sales, only 45,000 GWh of incremental renewables were added compared to 74,000–75,000 GWh added in studies that do not include the rest of the Scoping Plan's measures. These incremental renewables are in addition to the 33,000 GWh renewables currently on-line to meet California's RPS.

The study found that three-fifths of the electricity savings impacts from achieving Scoping Plan resource goals came from energy efficiency, rooftop PV, and combined heat and power while two-fifths of the savings came from renewables. The complementary programs both saved energy and flattened the system peak load, with 2020 capacity savings at system peak of up to 15 percent (CHP 4,700 MW, EE 6,400 MW, and rooftop PV 1,800 MW).

The study found that the potential impacts of adding large amounts of intermittent renewables on natural gas-fired generation were muted by two programs that had significant direct impacts on natural gas use and the type of plants to be built. The Scoping Plan's energy savings targets translated into an incremental 4,700 MW of combined heat and power capacity. Twenty percent of all California's natural gas used and 26 percent of all natural gas generation will be consumed by combined heat and power by 2020. This policy reduced electricity sales to end-use customers but did not create a proportional reduction in natural gas use. It also added a large amount of baseload generation to Southern California, since this is where 60 percent of potential host sites for large combined heat and power are located.

The once-through cooling policies also affected potential impacts of intermittent renewables because much of the generation that needs to be retrofitted or replaced serves local functions that continue to be supported by local generation. Of the 15,069 MW of existing OTC units, 964 MW were retained, 1,450 MW have recently been repowered, and 7,758 MW were replaced with new, efficient units. By 2020, depending on the case, between 11 and 23 percent of natural gas-fired generation in California is consumed by power plants associated with the OTC issue. Once combined heat and power targets and once-through cooling replacements were made, only a few new natural gas plants had to be added to meet local capacity and energy needs. These were in the SMUD, Turlock Irrigation District, and Imperial Valley control areas, which have no once-through cooling units and limited large hosts for new combined heat and power.

The amount of natural gas units added did not change between the Reference case and the two bookend cases. This suggests that the combined heat and power additions and used changes to meet OTC policies provided sufficient gas flexibility that more units were not needed even in the more intermittent wind cases. But the capacity factors for generic additions and OTC replacement combined cycles, which start out at normal baseload levels, drop to much lower levels by 2020 for both of the bookend cases, making the long-run cost-effectiveness of these combined cycles questionable. This suggests that the sample compliance path staff modeled was not optimal if the large amount of CHP baseload is added. Thus, a key finding of the study is that none of these policies should be assessed in isolation. To test these conclusions, additional model runs could be done which lower the amount of must-take CHP and switch some of the OTC combined cycles to combustion turbines.

For electricity generation, the WECC-wide amount of natural gas did decrease in both full Scoping Plan cases by 15 percent, due to the contributions of energy efficiency, rooftop PV, renewables, and CHP.

Reductions were not distributed evenly; more than half of the gas reductions occurred out-of-state. In-state gas-fired generation went down only by 10 percent in the High Wind case and 12 percent in the High Solar case when compared to the Reference case in 2020 (see **Table 10**). This suggests that out-of-state natural gas is the marginal source and that in-state gas is used for local reliability or ancillary services. In the reference case, slightly over half of all natural gas-fired electricity comes from out-of-state. In the Scoping Plan cases, gas use is evenly divided between in-state and out-of-state.

The High Wind case both used more wind than an equivalent amount of solar energy and used more in-state natural gas. This is consistent with the need to use gas-fired units for local reliability and the expectation that wind needs more intermittency support than does solar due to its daily load profile and greater variability. Also, as **Table 10** shows, total natural gas consumption rose slightly in both bookend cases as large amounts of CHP, all fueled by natural gas were added to the system.

**Table 10: California Natural Gas Use (BCF/day)**

| | 2012 | 2016 | 2020 | 2020 Change from Case 1 |
|---|---|---|---|---|
| Case 1: Reference | 2.36 | 2.57 | 2.88 | |
| Case 2: High Solar | 2.34 | 2.45 | 2.52 | -12% |
| Case 3: High Wind | 2.34 | 2.48 | 2.60 | -10% |

Source: Energy Commission, Electricity Analysis Office

With these preferred resource policies built in, the differences between the High Wind and High Solar cases were more modest than they would have been had less ambitious complementary programs been assessed. The study found that:

- A resource mix with high proportion of wind required more in-state natural gas to serve as back-up than the High Solar case did.
- More impacts were seen in Southern California than Northern California. While wind is distributed across the state, solar resources are almost completely concentrated in Southern California. OTC units and potential CHP sites are also concentrated in the South. This indicates that there may be more system impacts and potential system stress in the southern transmission grid.

Results from this study are indicative but are limited both by the assumptions used and the fact that the model used does not incorporate integrated local area functions and ramping constraints. Its findings would need to be tested with more sensitivities and with other models.

Study results indicate that at least three areas deserve further research because the assumptions made in this study have a major impact on whether intermittent renewables influence the type of proxy natural gas unit needed to firm and total fuel use. First, alternative levels of CHP should be tested, as the addition of so much baseload power in-state and in Southern California may be difficult to achieve with existing emission credit problems and the lack of a mechanism to make it happen. Second, alternative assumptions about compliance with OTC mitigation requirements should be tested because the interactions of all the Scoping Plan programs lead to unrealistic capacity factors in the new combined cycles by 2020. Third, another area for further work is over-generation, a condition when more generation is provided than load is available to consume it and rules need to be applied to back down generation in an uneconomic manner. Staff observed some over-generation situations but did not have time to explore this issue. Staff proposes to take a closer look at all three of these issues in follow-up work.

## Acronyms

| Acronym | Definition |
|---|---|
| AB 32 | Assembly Bill 32 |
| ARB | Air Resources Board, lead agency for AB 32 |
| BCF/day | Billion cubic feet per day |
| California ISO | California Independent System Operator |
| CDWR | California Department of Water Resources |
| CHP | Combined heat and power |
| CPUC | California Public Utilities Commission |
| CREZ | Competitive Renewable Energy Zone |
| EE | Energy efficiency |
| Energy Commission | California Energy Commission |
| ERC | Emission Reduction Unit |
| GBTU | Giga British Thermal Unit |
| GHG | Greenhouse gas |
| GWh | Gigawatt-hour |
| *IEPR* | *Integrated Energy Policy Report* |
| IIG | Imperial Irrigation District |
| IOU | Investor-owned utility |
| IRP | Integrated Resource Plan |
| KW | Kilowatt |
| LADWP | Los Angeles Department of Water & Power |
| LAR | Local reliability area |
| LCR | Local capacity requirement |
| LSE | Load serving entities |
| MMBTU | Million British Thermal Units |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NCI | Navigant Consulting, Inc. |
| NREL | National Renewable Energy Laboratory |

## Acronyms (continued)

| Acronym | Definition |
|---|---|
| OTC | Once-through cooling |
| PG&E | Pacific Gas and Electric |
| PIER | Public Interest Energy Research |
| POU | Publicly owned utility |
| PV | Photovoltaic |
| RETI | Renewable Energy Transmission Initiative |
| RPS | Renewables Portfolio Standard |
| SCAQMD | South Coast Air Quality Management District |
| SCE | Southern California Edison |
| SDG&E | San Diego Gas & Electric |
| SMUD | Sacramento Municipal Utilities District |
| SWRCB | State Water Resources Control Board |
| TID | Turlock Irrigation District |
| WAPA | Western Area Power Administration |
| WECC | Western Electricity Coordinating Council |

# APPENDIX 1: Renewable Energy Case Descriptions

## In-State Renewable Resource Cases

This study investigates the potential impacts on natural gas units and consumption that might occur with a 33 percent California renewables goal. California's 2002 Renewables Portfolio Standard (RPS) requires retail sellers to procure 20 percent renewable energy by 2010. The law requires publicly owned utilities to set their own RPS goals recognizing the intent of the Legislature to attain a target of 20 percent of California retail sales of electricity from renewable energy by 2010. On November 17, 2008, Governor Schwarzenegger signed Executive Order S-14-08, setting a renewable energy goal of 33 percent by 2020 for California. Staff developed three statewide RPS cases to provide a 20 percent RPS case and two "bookend" estimates of the potential changes this level of renewable energy may impose on the timing and use of natural gas for electricity generation in California. These cases include a 20 percent RPS Reference case by 2012, a 33 percent RPS High Wind case, and a 33 percent RPS High Solar case by 2020.[15]

Staff estimates that about 62,000 GWh of renewable will be needed for the 20 percent Reference case. Assuming achievement of the energy efficiency, combined heat and power, and rooftop PV goals included in the California Air Resources Board's AB 32 *Climate Change Scoping Plan*, roughly 78,000 GWh will be needed to achieve 33 percent renewables. Staff estimated existing renewable energy to be around 32,500 GWh. For in-state investor-owned utility (IOU) and publicly owned utility (POU) generation, staff used the levels reported in the *2007 IEPR*: 25,000 GWh and 5,000 GWh, respectively. The *2007 Net System Power Report* and staff analysis was used to estimate out-of-state IOU and POU generation at 500 GWh and 2,000 GWh, respectively.

Following from these estimates of retail sales and existing renewable generation, staff estimates about 29,000 GWh of additional renewable energy is needed for the Reference case. Staff estimates about 45,500 GWh of renewable energy will be needed to move from existing renewable generation to the High Wind and High Solar cases.

The first milestone year used in the cases was 2012. All three cases include the same mix of renewables through 2012. This mix is based on the amount of new transmission expected in the Tehachapi by 2012 and signed contracts (IOU and POU) for Energy Commission RPS-

[15] None of the scenarios included in this study meet the biopower goal of providing 20 percent of the RPS goals with biomass and biogas (Executive Order S-06-06). In support of the April 21, 2009, workshop on biopower, staff developed a high biomass/distribution-level photovoltaic (DG PV) scenario that meets 20 percent of the 33 percent goal with biomass and biopower. Because the impacts of this scenario on California's gas-fired power plants would be similar to the impacts of the High Solar Case, the biomass/DG PV scenario was not included in this analysis.

eligible technologies with expected on-line dates of 2011 or before.[16] For IOUs, all three cases were designed to achieve 20 percent RPS by 2012. There was not enough generation from existing contracts expected to be on-line by 2011 to meet the Reference case. To bring the IOU RPS energy up to the required level, the cases assume the addition of about 1,100 GWh (160 MW) of geothermal by 2012 from the Imperial North-A competitive renewable energy zone (CREZ) in the Renewable Energy Transmission Initiative (RETI) Phase 1B report.[17] This CREZ was selected because it does not require incremental bulk transmission. Recognizing that POUs have set their own RPS goals and eligibility criteria, no additional renewables were added to the POUs through 2012 beyond signed RPS contracts for wind, geothermal, solar, biomass, biogas, and small hydro power.[18] The case achieved about 14 percent of POU retail sales by 2012.

Building on the 2012 mix, the Reference case added 5,600 GWh from signed RPS contracts (IOU and POU) for Energy Commission RPS-eligible technologies with expected on-line dates after 2011 and before 2020. It also added about 3,800 GWh (485 MW) of geothermal in RETI CREZ Imperial North-A based on geothermal projects included in the long-term procurement plans of Imperial Irrigation District and Los Angeles Department of Water and Power.

The High Wind case for 33 percent added about 25,500 GWh of wind to the 2012 mix. To build this case, staff first looked to see if there were additional signed contracts for wind energy that were expected to come on-line after 2011 and before 2020. There were no IOU contracts meeting these criteria, but there were POU contracts for wind in Palm Springs (about 20 GWh) and Tehachapi (about 460 GWh). Next, staff selected wind from the CREZs in the order used in the High Wind case of the forthcoming CPUC 33 percent Implementation Analysis until the case achieved at least 45,500 GWh.[19]

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[16] The source used for IOU contracts was California Energy Commission, Database of Investor-Owned Utilities' Contracts for Renewable Generation, Updated January 18, 2009. http://www.energy.ca.gov/portfolio/contracts_database.html. The source for the POU contracts was the following report and associated POU RPS contract database: California Energy Commission, December 2008, *The Progress of California's Publicly Owned Utilities in Implementing Renewable Portfolio Standards*, Consultant Report, and CEC-300-2008-005. Authors: Galen Barbose, Ryan Wiser – KEMA, Inc. http://www.energy.ca.gov/2008publications/CEC-300-2008-005/index.html.

[17] Renewable Energy Transmission Initiative, Phase 1B, RETI-1000-2008-003-F, revised March 4, 2009, http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF.

[18] Large hydropower is not included in the existing or additional renewables in the scenarios prepared for this study. However, a number of POUs allow large hydroelectric power to count as RPS-qualifying renewable energy. For more information, see Table 1 of California Energy Commission, December 2008, *The Progress of California's Publicly Owned utilities in Implementing Renewables Portfolio Standards*, Consultant Report, and CEC-300-2008-005. Authors: Galen Barbose, Ryan Wiser – KEMA, Inc. http://www.energy.ca.gov/2008publications/CEC-300-2008-005/index.html.

[19] CPUC, January 15, 2009, 33 Percent Implementation Analysis Working Group Meeting.

Staff used information from the RETI Phase 1B report to determine which resources would be added by 2016 and 2020.[20] Staff added about 9,500 GWh by 2016 in the Palm Springs, Fairmont, Baja, and San Diego South CREZs because these CREZs would connect to existing transmission and/or new transmission expected to be available by 2016, namely, Devers/Palo Verde 2, Tehachapi, and Sunrise/Green Path. In addition, the case includes 15,500 GWh of wind from San Bernardino-Lucerne, Round Mountain, Barstow, Mountain Pass, and British Columbia. The RETI Phase 1B report indicates that renewable energy from these CREZs is likely to be interconnected by 2016 or 2020 but does not identify specific transmission lines. Staff assumed energy from these CREZs would be available by 2020.

For most CREZs, the amount of energy in the High Wind case added to the 2012 mix does not exceed the amount of energy included in the CPUC High Wind case. However, compared to the CPUC High Wind case, which includes more wind from Barstow and includes wind from Mountain Pass and British Columbia, only wind projects with a ranked cost of $40 or less were chosen from the RETI CREZs to be included in this case. Also, transmission upgrades were assumed to be easier to permit in Canada than Mexico, so generation from British Columbia was favored over North Baja. Wind from North Baja was limited to 400 MW, the amount that can be transmitted over the existing Baja/Miguel transmission line. Lastly, the proposed Mother Road National Monument is expected to run through both Pisgah A and B, so staff did not select wind generation from these CREZs.

The High Solar case added about 25,500 GWh of solar (PV and solar thermal electric) to the 2012 mix. Staff began building this case by adding 7,500 GWh of signed IOU RPS contracts for PV and solar thermal electric energy expected to come on-line after 2011 and before 2020. There were no POU contracts meeting these criteria.

Next, except for the Fairmont CREZ, staff selected solar from the CREZs in the order used in the High Solar Case of the forthcoming CPUC 33 percent Implementation Analysis until the case achieved at least 45,500 GWh. The Fairmont CREZ was excluded because staff believed that the amount of solar included in the Fairmont CREZ was being reconsidered by the RETI process. Regarding the Needles CREZ, staff included three pre-identified projects and excluded the Proxy project.

In all but one case, the amount of solar energy from each CREZ did not exceed the amount of energy included from that CREZ in the CPUC's High Solar case. However, the Energy Commission's High Solar case has more solar energy from the San Bernardino-Lucerne CREZ than the amount of energy from this CREZ in the CPUC's High Solar case because the RETI Phase 1B report indicated that more solar was available from this CREZ and additional energy was needed to meet the renewable net short of 45,500 GWh.

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[20] Table 3-19: Development Timeframe by CREZ, *Renewable Energy Transmission Initiative, Phase 1B*, RETI-1000-2008-003-F, revised March 4, 2009, [http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF](http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF).

As noted above, the proposed Mother Road National Monument is expected to run through both Pisgah A and B. This case did not include Pisgah A but did include Pisgah B as a placeholder for additional solar energy from the Southeastern renewable resource area, recognizing that a High Solar mix would require new transmission through this solar-rich area. The High Solar case excluded projects likely to be affected by proposed Catellus land restrictions. [21]

**Table 1-1: Renewable Cases—2020 Energy by Resource Type**

| | Case 1 Reference Case | | Case 2 High Wind | | Case 3 High Solar | |
|---|---|---|---|---|---|---|
| | GWh | Percent | GWh | Percent | GWh | Percent |
| Biogas | 2,000 | 3% | 2,000 | 3% | 2,000 | 3% |
| Biomass | 6,300 | 10% | 6,300 | 8% | 6,300 | 8% |
| Geothermal | 24,900 | 40% | 18,500 | 24% | 18,500 | 24% |
| Small Hydro | 5,000 | 8% | 5,000 | 6% | 5,000 | 6% |
| Solar (PV and Thermal) | 5,800 | 9% | 3,300 | 4% | 28,900 | 37% |
| Solar/Biomass Hybrid | 1,000 | 2% | 1,000 | 1% | 1,000 | 1% |
| Wind | 16,800 | 27% | 41,800 | 54% | 16,300 | 21% |
| **Total RPS Generation** | **61,800** | **100%** | **78,000** | **100%** | **78,000** | **100%** |

Source: Energy Commission REO staff (see Appendix 1 for description.) The Case 2 and 3 use the load forecast adjusted by the AB 32 Scoping Plan.

Note: Totals do not add due to rounding

## Out-of-State and Other Renewable RPS Resource Additions

As part of the analysis, staff assumed that all other states within the WECC with a renewable energy requirement would meet that requirement. As a guide for renewable energy requirements, staff used information obtained from the Database of State Incentives for Renewables and Efficiency (DSIRE) website located at www.dsireusa.org. This website provides each state's renewable energy requirements, including resource technology type

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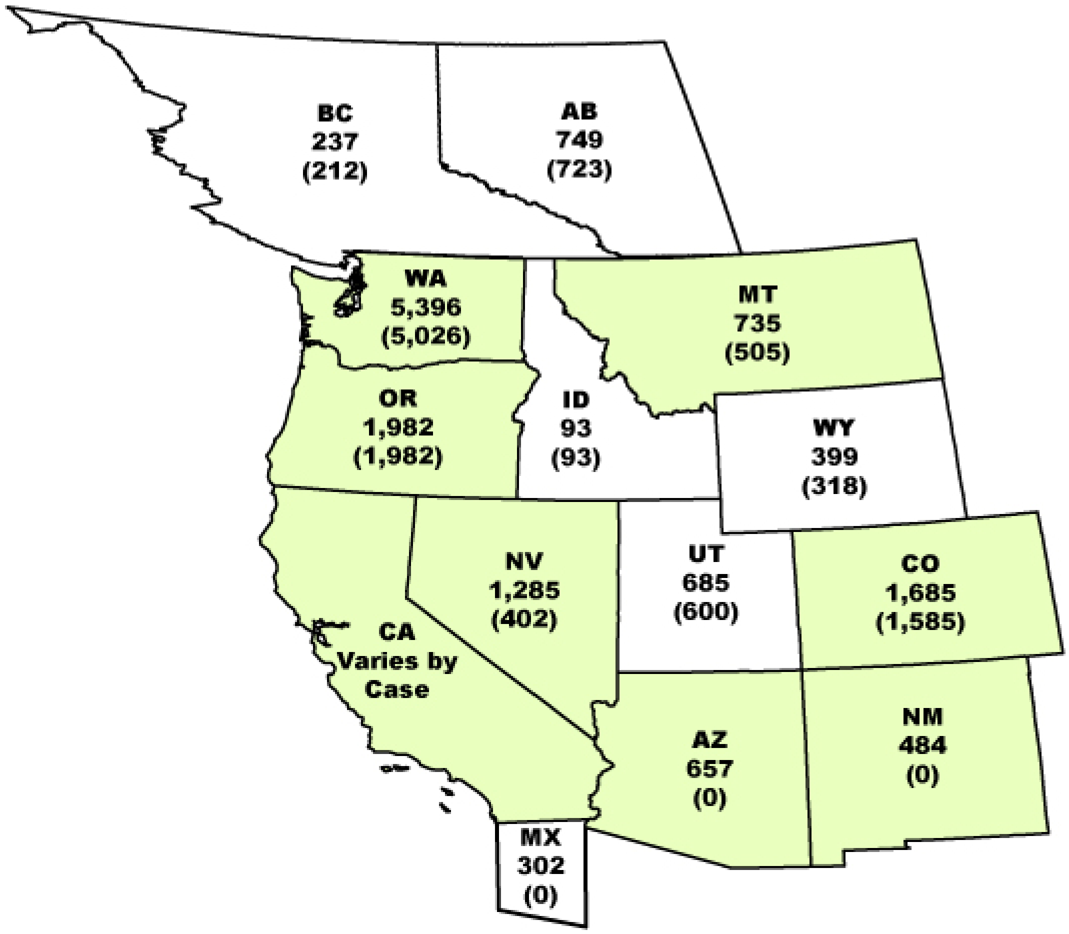
[21] Staff believes solar projects in Pisgah-B are not likely to be affected by the Wildlands Conservancy - Catellus Agreement because they are west of the area that may be excluded from renewable energy development. See http://www.landgrant.org/catellus-mohave.htm and http://feinstein.senate.gov/public/index.cfm?FuseAction=NewsRoom.PressReleases&ContentRecord_id=1b2bfd79-5056-8059-769b-efa99ad34933.

and any energy multipliers used in calculating qualifying renewable energy. Loads for each state used to calculate RPS requirements were taken from Ventyx Market Analytics database, using only those portions of a state's load subject to the RPS requirement.

To determine a states renewable energy position, generation from existing, qualifying renewable energy sources were tabulated for the three study years (2012, 2016, and 2020). Those renewable energy totals were compared to each state's RPS requirement for each year of the study. Where a renewable energy shortfall occurred, assumed resources used to meet each state's requirement were placed in that state using the *Renewable Energy Atlas of the West*[22] as a guide in considering what type of renewable energy resources could be developed in each state (that is, wind resources in "windy" areas and geothermal resources where appropriate conditions exist). These generic renewable additions were used to bridge the gaps between renewable energy generation and the state requirement. **Figure 1-1** is a map of the WECC showing generic resource additions by state and the associated energy produced by generic resource additions.

[22] *Land and Water Fund of the Rockies*, A Project of the Hewlett Foundation and the Energy Foundation, published July, 2002.

**Figure 1-1: Installed Renewable Capacity in WECC RPS and IRP Filings (MW)**




Source: Energy Commission staff—values shown in parenthesis are amount of installed wind included in the total.

Note: States with RPS are in green.

# APPENDIX 2: Production Cost Model Assumptions Common to All Cases

Assumptions are comprised of:

- Load forecasts
- Existing California renewables to meet RPS
- OTC compliance assumptions
- Methodology to develop consistent hourly wind and load shapes
- Fuel price forecasts

**Table 2-1: WECC Peak Load and Energy Demand Forecasts**

| Year | WECC | |
|---|---|---|
| | Peak Load (MW) | Annual Energy (GWh) |
| 2012 | 172,089 | 886,260 |
| 2016 | 184,828 | 948,936 |
| 2020 | 196,599 | 1,006,997 |
| Growth Rate | 1.68% | 1.61% |

Source: *California Energy Demand 2008–2018: Staff Revised Forecast, Final Staff Forecast, 2nd Edition*, CEC-200-2007-015-SF2, November 27, 2007. Forecast extended to 2020 by Energy Commission staff. Out-of-state forecasts from Ventyx Spring 2008 NERC data release.

**Table 2-2: WECC Summary Demand Statistics — 2012**

| Transmission Area | Peak Load (MW) | Peak Growth* | Annual Energy (GWh) | Energy Growth* | Load Factor |
|---|---|---|---|---|---|
| Arizona (including Palo Verde Hub) | 19,626 | 2.61% | 88,391 | 2.53% | 51.4% |
| British Columbia | 11,888 | 1.13% | 67,767 | 1.32% | 65.1% |
| California ISO - Northern California | 20,978 | 1.25% | 101,531 | 1.02% | 55.2% |
| California ISO - Southern California | 29,796 | 1.38% | 141,027 | 1.17% | 54.0% |
| California ISO - Zone Path 26 | 1,689 | 1.18% | 9,026 | 0.96% | 61.0% |
| Colorado | 11,739 | 2.15% | 62,779 | 2.10% | 61.0% |
| Imperial Irrigation District | 1,195 | 2.60% | 4,309 | 2.51% | 41.2% |
| Imperial Valley - North Gila | 0 | 0 | 0 | 0 | 0 |
| Los Angeles Department of Water & Power | 6,441 | 0.32% | 31,135 | 0.36% | 55.2% |
| New Mexico | 4,619 | 2.28% | 26,825 | 2.22% | 66.3% |
| Northern Baja California - CFE | 2,769 | 4.91% | 15,039 | 4.91% | 62.0% |
| Northwest | 36,487 | 1.28% | 217,842 | 1.33% | 68.2% |
| Sacramento Municipal Utility District | 5,039 | 1.42% | 20,769 | 1.28% | 47.1% |
| Southern Nevada | 8,869 | 1.92% | 36,272 | 1.75% | 46.7% |
| Turlock Irrigation District | 515 | 1.65% | 2,722 | 1.35% | 60.3% |
| Utah | 6,815 | 2.59% | 36,343 | 2.51% | 60.9% |
| Wyoming | 3,624 | 2.20% | 24,482 | 2.34% | 77.1% |

Source: *California Energy Demand 2008–2018: Staff Revised Forecast, Final Staff Forecast, 2nd Edition*, CEC-200-2007-015-SF2, November 27, 2007. Forecast extended to 2020 by Energy Commission staff. Out-of-state forecasts from Ventyx Spring 2008 NERC data release.

* Eight Year Annualized Growth Rate (2012–2020).

**Table 2-3: California Peak Demand by LSE: Noncoincident Peak Demand (MW)**

| Agency | Zone | 2012 | 2016 | 2020 |
|---|---|---|---|---|
| Alameda | PG&E | 68.8 | 71.1 | 73.2 |
| Biggs | PG&E | 7.5 | 8.0 | 8.7 |
| Calaveras Public Power Agency | PG&E | 5.6 | 5.7 | 5.8 |
| WAPA | PG&E | 296.0 | 294.6 | 293.1 |
| Gridley | PG&E | 12.0 | 13.0 | 14.0 |
| Healdsburg | PG&E | 23.8 | 25.2 | 26.5 |
| Lassen Municipal Utility District | PG&E | 30.5 | 32.3 | 33.9 |
| Lodi | PG&E | 155.5 | 170.3 | 185.8 |
| Lompoc | PG&E | 32.4 | 34.2 | 36.0 |
| Merced Irrigation District | TID | 87.7 | 92.4 | 96.7 |
| Modesto Irrigation District | MID | 775.8 | 829.2 | 884.1 |
| Palo Alto | PG&E | 191.4 | 195.0 | 197.5 |
| PG&E Bundled | PG&E | 20,255.0 | 21,396.8 | 22,522.2 |
| PG&E Direct Access | PG&E | 966.6 | 966.6 | 966.6 |
| Plumas-Sierra Rural Electric Cooperation | PG&E | 30.9 | 32.4 | 34.0 |
| Port of Stockton | PG&E | 4.3 | 4.7 | 5.0 |
| Power and Water Resource Purchasing Authority | PG&E | 56.8 | 57.6 | 58.2 |
| Redding | SMUD/Western | 279.0 | 301.8 | 326.3 |
| Roseville | SMUD/Western | 377.3 | 415.5 | 456.0 |
| San Francisco | PGAE | 131.9 | 133.6 | 135.5 |
| Shasta Dam Area Public Utility District | SMUD/Western | 35.4 | 36.5 | 37.3 |
| Silicon Valley Power | PGAE | 508.7 | 530.4 | 549.2 |
| Tuolumne County Public Power Agency | PGAE | 4.7 | 4.8 | 4.9 |
| Turlock Irrigation District | TID | 515.1 | 550.3 | 586.8 |
| Ukiah | PGAE | 37.8 | 39.4 | 40.8 |
| SMUD | SMUD/Western | 3,363.0 | 3,559.2 | 3,733.0 |
| Anaheim | SCE | 599.6 | 619.7 | 637.3 |
| Anza Electric Cooperative, Inc. | SCE | 21.2 | 23.2 | 25.3 |
| Azusa | SCE | 66.9 | 69.5 | 71.7 |
| Banning | SCE | 54.7 | 59.7 | 64.8 |
| Bear Valley Electric Service | SCE | 18.8 | 19.4 | 19.9 |
| Boulder City/Parker Davis | SCE | 20.1 | 21.9 | 23.9 |
| Colton | SCE | 104.4 | 113.7 | 123.3 |
| Metropolitan Water Department | SCE | 238.6 | 238.7 | 238.9 |
| Rancho Cucamonga | SCE | 14.6 | 15.9 | 17.3 |
| Riverside | SCE | 655.5 | 716.0 | 778.5 |
| SCE Bundled | SCE | 21,350.8 | 22,750.0 | 24,129.4 |
| SCE Direct access | SCE | 1,615.0 | 1,615.0 | 1,615.0 |
| Valley Electric Association, Inc. | SCE | 1.4 | 1.4 | 1.4 |

**Table 2-3: California Peak Demand by LSE: Noncoincident Peak Demand (MW) (Continued)**

| Agency | Zone | 2012 | 2016 | 2020 |
|---|---|---|---|---|
| Vernon | SCE | 202.9 | 206.9 | 208.7 |
| Victorville Municipal | SCE | 4.6 | 4.9 | 5.1 |
| Los Angeles Department of Water and Power | LADWP | 5,839.6 | 5,928.1 | 6,003.5 |
| Burbank | LADWP | 294.6 | 297.2 | 299.0 |
| Glendale | LADWP | 310.1 | 311.0 | 310.7 |
| Pasadena | SCE | 305.6 | 308.1 | 310.5 |
| SDG&E Bundled | SDGE | 4,257.6 | 4,532.8 | 4,801.7 |
| SDG&E Direct Access | SDGE | 598.1 | 598.1 | 598.1 |
| Imperial Irrigation District | IID | 1,194.6 | 1,327.0 | 1,466.7 |
| Mountain Utilities | OTHER | 1.1 | 1.1 | 1.1 |
| Needles | OTHER | 10.2 | 10.3 | 10.3 |
| Pacificorp | OTHER | 148.9 | 149.0 | 148.8 |
| Sierra Pacific Power Company | OTHER | 82.9 | 83.4 | 83.7 |
| Surprise Valley Electrical Corporation | OTHER | 13.3 | 13.2 | 13.1 |
| Trinity Public Utility District | PGE | 17.7 | 17.8 | 17.9 |
| Truckee-Donner Public Utility District | OTHER | 24.1 | 24.2 | 24.2 |
| CDWR-N | PG&E | 741.9 | 741.9 | 741.9 |
| CDWR-ZP26 | PG&E | 385.3 | 385.3 | 385.3 |
| CDWR-S | SCE | 927.4 | 927.4 | 927.4 |

Source: California Energy Demand 2008—2018: Staff Revised Forecast, Final Staff Forecast, 2nd Edition, CEC-200-2007-015-SF2, November 27, 2007. Forecast extended to 2020 by Energy Commission staff.

**Table 2-4: Existing California Renewable Generation (GWh) Forecast of 2009 Generation From Ventyx's Market Analytics Simulation Model**

| California Small Hydro by Control Area | | | | | | |
|---|---|---|---|---|---|---|
| **2009** | **Dependable Capacity (MW)** | **Generation (GWh)** | | | | |
| California ISO | 886 | 3681 | | | | |
| Imperial Irrigation District | 81 | 295 | | | | |
| Los Angeles DWP | 31 | 140 | | | | |
| SMUD | 105 | 300 | | | | |
| Turlock Irrigation District | 11 | 44 | | | | |
| **Total** | **1,114** | **4,460** | | | | |
| **Non-Hydro Renewable Generation by Region** | | | | | | |
| **2009 (GWh)** | **Biomass** | **Geothermal** | **Refuse** | **Wind** | **Wood** | **Grand Total** |
| Northern California | 902 | 7,473 | 137 | 1,741 | 2,797 | 13,050 |
| Southern California | 916 | 2,627 | 282 | 3,062 | 374 | 7,261 |
| San Diego | 177 | | | 141 | 0 | 318 |
| Imperial | 0 | 3,727 | | | 359 | 4,085 |
| **Total** | **1,994** | **13,827** | **419** | **4,944** | **3,530** | **24,714** |
| **Total Hydro + Non-Hydro** | | | | | | **29,174** |

Source: Energy Commission staff, production cost model simulation results.

**Table 2-5: Once-Through Cooling Units – Compliance Assumptions Used in This Study**

| | Unit Name | Dependable (MW) | Owner | LRA | Retirement Year | Return Size Dependable (MW) | Return Year | Inertia MW_Sec | Inertia for New CC MW_Sec | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Harbor 1 | 75 | LADWP | LA Basin | | | | Not Available | | Assume reclaim water found for wet cooling |
| 2 | Haynes 1 | 222 | LADWP | LA Basin | | | | Not Available | | Assume reclaim water found for wet cooling |
| 3 | Haynes 2 | 222 | LADWP | LA Basin | | | | Not Available | | Assume reclaim water found for wet cooling |
| 4 | Haynes 5 | 341 | LADWP | LA Basin | 12/31/2012 | 300 | 1/1/2016 | Not Available | | CTs for reserve margin not for inertia |
| 5 | Haynes 6 | 341 | LADWP | LA Basin | 12/31/2012 | 300 | 1/1/2016 | Not Available | | CTs for reserve margin not for inertia |
| 6 | Scattergood 1 | 179 | LADWP | LA Basin | 12/31/2014 | 200 | 1/1/2016 | Not Available | | CTs for reserve margin not for inertia |
| 7 | Scattergood 2 | 179 | LADWP | LA Basin | 12/31/2014 | 200 | 1/1/2016 | Not Available | | CTs for reserve margin not for inertia |
| 8 | Scattergood 3 | 445 | LADWP | LA Basin | | | | Not Available | | Assume reclaim water found for wet cooling |
| 9 | Encina 1 | 106 | NRG Energy | San Diego | 1/1/2010 | 279 | 1/1/2012 | Not Available | | Needed for LCR/inertia |
| 10 | Encina 2 | 103 | NRG Energy | San Diego | 1/1/2010 | 279 | 1/1/2012 | Not Available | | Needed for LCR/inertia |

## Table 2-5: Once-Through Cooling Units – Compliance Assumptions Used in This Study (Continued)

| | Unit Name | Dependable (MW) | Owner | LRA | Retirement Year | Return Size Dependable (MW) | Return Year | Inertia MW/Sec | Inertia for New CC MW/Sec | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| 11 | Encina 3 | 109 | NRG Energy | San Diego | 1/1/2010 | | | Not Available | | Assume all out same year out as Sunrise Power Link comes on-line |
| 12 | Encina 4 | 299 | NRG Energy | San Diego | 12/31/2019 | | | Not Available | | Assume all out same year out as Sunrise Power Link comes on-line |
| 13 | Encina 5 | 329 | NRG Energy | San Diego | 12/31/2019 | | | Not Available | | Assume all out same year out as Sunrise Power Link comes on-line |
| 14 | South Bay 1 | 145 | LS Power | San Diego | 12/31/2013 | | | Not Available | | Assume all out same year out as Sunrise Power Link comes on-line |
| 15 | South Bay 2 | 149 | LS Power | San Diego | 12/31/2013 | | | Not Available | | Assume all out same year out as Sunrise Power Link comes on-line |
| 16 | South Bay 3 | 174 | LS Power | San Diego | 12/31/2013 | 300 | 1/1/2016 | Not Available | | Needed for LCR/inertia |
| 17 | South Bay 4 | 221 | LS Power | San Diego | 12/31/2013 | 300 | 1/1/2016 | Not Available | | Needed for LCR/inertia |
| 18 | Alamitos 1 | 175 | AES | LA Basin | 12/31/2016 | 300 | 1/1/2020 | 634 | 1,465 | Needed for LCR/inertia |

## Table 2-5: Once-Through Cooling Units – Compliance Assumptions Used in This Study (Continued)

| | Unit Name | Dependable (MW) | Owner | LRA | Retirement Year | Return Size Dependable (MW) | Return Year | Inertia MW/Sec | Inertia for New CC MW/Sec | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| 19 | Alamitos 2 | 175 | AES | LA Basin | 12/31/2016 | 300 | 1/1/2020 | 634 | 1,465 | Needed for LCR/inertia |
| 20 | Alamitos 3 | 320 | AES | LA Basin | 12/31/2016 | 300 | 1/1/2020 | 1,743 | 1,465 | Needed for LCR/inertia |
| 21 | Alamitos 4 | 320 | AES | LA Basin | 12/31/2016 | 300 | 1/1/2020 | 1,743 | 1,465 | Needed for LCR/inertia |
| 22 | Alamitos 5 | 480 | AES | LA Basin | 12/31/2016 | 300 | 1/1/2020 | 1,871 | 1,465 | Needed for LCR/inertia |
| 23 | Alamitos 6 | 480 | AES | LA Basin | 12/31/2016 | 300 | 1/1/2020 | 1,871 | 1,465 | Needed for LCR/inertia |
| 24 | Huntington Beach 1 | 215 | AES | LA Basin | 1/1/2017 | 300 | 1/1/2020 | 1,101 | 1,465 | Needed for LCR/inertia |
| 25 | Huntington Beach 2 | 215 | AES | LA Basin | 1/1/2017 | 300 | 1/1/2020 | 1,101 | 1,465 | Needed for LCR/inertia |
| 26 | Huntington Beach 3 | 215 | AES | LA Basin | | | | | | Recently Repowered |
| 27 | Huntington Beach 4 | 215 | AES | LA Basin | | | | | | Recently Repowered |
| 28 | El Segundo 3 | 335 | NRG Energy | LA Basin | 12/31/2013 | 250 | 1/1/2016 | 1,750 | 1,465 | Needed for LCR/inertia |
| 29 | El Segundo 4 | 335 | NRG Energy | LA Basin | 12/31/2013 | 250 | 1/1/2016 | 1,750 | 1,465 | Needed for LCR/inertia |
| 30 | Mandalay 1 | 215 | Reliant | Big Creek | 12/31/2015 | | | 1,097 | | Assumes transmission fix |
| 31 | Mandalay 2 | 215 | Reliant | Big Creek | 12/31/2015 | | | 1,097 | | Assumes transmission fix |
| 32 | Ormond Beach 1 | 750 | Reliant | Big Creek | 12/31/2015 | | | 2,582 | | Assumes transmission fix |
| 33 | Ormond Beach 2 | 750 | Reliant | Big Creek | 12/31/2015 | | | 2,582 | | Assumes transmission fix |

**Table 2-5: Once-Through Cooling Units – Compliance Assumptions Used in This Study (Continued)**

| | Unit Name | Dependable (MW) | Owner | LRA | Retirement Year | Return Size Dependable (MW) | Return Year | Inertia MW/Sec | Inertia for New CC MW/Sec | Notes |
|---|---|---|---|---|---|---|---|---|---|---|
| 34 | Redondo Beach 5 | 175 | AES | LA Basin | 12/31/2013 | 300 | 1/1/2016 | 638 | 1,465 | Needed for LCR/inertia |
| 35 | Redondo Beach 6 | 175 | AES | LA Basin | 12/31/2013 | 300 | 1/1/2016 | 638 | 1,465 | Needed for LCR/inertia |
| 36 | Redondo Beach 7 | 480 | AES | LA Basin | 12/31/2013 | 300 | 1/1/2016 | 1,873 | 1,465 | Needed for LCR/inertia |
| 37 | Redondo Beach 8 | 480 | AES | LA Basin | 12/31/2013 | 300 | 1/1/2016 | 1,873 | 1,465 | Needed for LCR/inertia |
| 38 | Contra Costa 6 | 340 | Mirant | Greater Bay | retired by 2016 | | | Not Applicable | | |
| 39 | Contra Costa 7 | 335 | Mirant | Greater Bay | retired by 2016 | | | Not Applicable | | |
| 40 | Morro Bay 3 | 340 | LS Power | | retired by 2016 | | | Not Applicable | | |
| 41 | Morro Bay 4 | 333 | LS Power | | retired by 2016 | | | Not Applicable | | |
| 42 | Moss Landing 1-2 | 1,020 | LS Power | | | | | Not Applicable | | Recently Repowered |
| 43 | Moss Landing 6 | 740 | LS Power | | 1/1/2017 | 1,000 | 1/1/2020 | Not Applicable | | Assume OTC replaced with dry cooling |
| 44 | Moss Landing 7 | 750 | LS Power | | 1/1/2017 | 500 | 1/1/2020 | Not Applicable | | Assume OTC replaced with dry cooling |
| 45 | Pittsburg 5 | 325 | Mirant | Greater Bay | retired by 2016 | | | Not Applicable | | Assume transmission fix |
| 46 | Pittsburg 6 | 320 | Mirant | Greater Bay | retired by 2016 | | | Not Applicable | | Assume transmission fix |
| 47 | Potrero 3 | 207 | Mirant | Greater Bay | 12/31/2015 | | | Not Applicable | | Assume transmission fix |

Source: Energy Commission staff, and *2007 IEPR Scenarios Analysis* – Second Addendum, August 2007.

## Energy Commission Approach to Developing Consistent Hourly Load and Wind Profiles

### *What Is a Wind Shape?*

A wind shape is a typified profile of electrical generation from a wind resource at a given location or across a given region. A wind shape can be derived from historically observed actual wind generation, models of wind generation that are a function of measured regional wind patterns (or other factors), or some combination of historical and statistical observations. Often a wind shape will span a number of hours sufficient to capture diurnal and other natural patterns within a given month or season.

The modeling approach employed by the Energy Commission staff to forecast future operating characteristics of the bulk power systems in California and the remainder of the Western Interconnection uses a chronological, hour-by-hour, least-cost dispatch of energy resources needed to meet a given load in an hour across all hours in a given year. While a simplistic approach of assuming some constant average wind generation value would be easy to employ, such a representation does not reflect the realities of an actual wind generation resource. A representation reflective of actual experience would be a desirable component of the model. While several wind shapes are available to the Energy Commission from various sources, these particular profiles are overly specific to particular resources, locations, and periods. From a modeling perspective, it would be desirable to deploy a wind shape that is broadly representative of wind generation patterns but not over-specified with respect to a particular wind generating resource or wind pattern occurring in a past calendar year. A generalized wind shape will meet this need.

### *How Is a Wind Shape Created?*

The National Renewable Energy Laboratory (NREL) has devoted time, resources, effort, and expertise to the task of producing time series data for wind generation in the West. The NREL Mesoscale historic simulated wind generation for 2004-2006, covering most regions in the West, was obtained by the Energy Commission courtesy of Michael Milligan with NREL's National Wind Technology Center (more information at: http://www.nrel.gov/wind/systemsintegration/pdfs/2008/lew_creating_dataset_wwsis.pdf).

The NREL Mesoscale wind shapes provided a valuable basis from which to create generalized wind profiles for regions in the West. One concern with simplistic generalizations of this type of data is the potential for the loss of characteristic variability. Techniques like simple averaging applied to these time series data can "wash out" or mute certain changes tied to diurnal or other natural factors. To preserve this characteristic variability, the Energy Commission employed a technique to arrive at composite hourly wind shapes based upon the three years of hourly simulated wind generation developed by NREL.

The collection of annual time series representing an hourly wind shape for each year and region were loaded into a data set accessible via a statistical software package. The annual hourly data for each region was used to calculate two separate averages. The first average calculated was a simple average for each hour of data across the three available years. The second average calculated was effectively an averaging of the duration curve representations for each of the annual time series. Duration curves represent time series data sans the chronology via plotting the series after sorting it, often from the highest values to the lowest. This average duration curve was then assigned the chronology information from the simple average by relating the duration curve representation of the simple average series to the average duration curve value, pairing the highest values from each series and so forth on through the lowest values of from each series.

Essentially, the core of this technique is also used by the Energy Commission staff in its development of load shapes. The key differences in the development of the Energy Commission load shapes and wind shapes are two. First, staff used five years of actual load data, 2002 through 2007, in the development of the Energy Commission load shapes while the Energy Commission wind shapes were developed from the NREL data, which cover 2004 through 2006. Second, techniques meant to preserve load patterns relative to specific days of the week were employed in the construction of the Energy Commission load shapes. The lack of such inherent daily patterns within any one week of observed wind generation data suggest that there would be nothing gained by applying “day of the week” pattern preservation techniques to the wind shape development process.

### *How Is a Wind Shape Used?*

Within the Energy Commission model, 33 separate NREL Mesoscale wind shapes are geographically assigned, matching the Energy Commission model topology to the NREL aggregate wind regions, throughout the western system. Each wind shape serves to approximate expected energy production in each hour from wind generation resources located in the associated region.

**Table 2-6: Annual Capacity Factor by Region**

| Region | Year | Capacity Factor |
|---|---|---|
| Tracy/Pittsburgh | 2004 | 19.4% |
| | 2005 | 41.8% |
| | 2006 | 18.2% |
| | Composite | 18.4% |
| Westwind/Antelope | 2004 | 39.5% |
| | 2005 | 41.3% |
| | 2006 | 38.6% |
| | Composite | 40.2% |
| Lugo | 2004 | 39.8% |
| | 2005 | 22.1% |
| | 2006 | 40.6% |
| | Composite | 40.9% |
| Devers | 2004 | 21.4% |
| | 2005 | 24.8% |
| | 2006 | 22.5% |
| | Composite | 22.3% |

Source: Energy Commission staff.

**Table 2-7: Rest of WECC Wind Profiles Implied Capacity Factors Annual Capacity Factor by Region**

| Region | 2004 | 2005 | 2006 | Composite |
|---|---|---|---|---|
| Arizona | 30.6% | 18.5% | 32.1% | 33.4% |
| NE Colorado | 24.9% | 35.3% | 26.5% | 25.7% |
| SE Colorado | 33.7% | 22.8% | 34.4% | 34.8% |
| Idaho | 22.0% | 26.1% | 24.1% | 23.4% |
| NE Montana | 26.1% | 36.9% | 27.8% | 26.9% |
| Central Montana | 36.3% | 40.5% | 39.0% | 38.0% |
| Southern Montana | 40.2% | 36.7% | 43.1% | 41.8% |
| NE New Mexico | 36.5% | 39.8% | 37.1% | 36.8% |
| Eastern New Mexico | 37.9% | 26.1% | 39.9% | 39.8% |
| Nevada | 26.6% | 22.5% | 28.4% | 27.2% |
| North Central Oregon | 23.2% | 16.6% | 26.4% | 24.4% |
| NE Oregon | 17.3% | 26.6% | 21.6% | 19.1% |
| Eastern Oregon | 25.6% | 27.8% | 29.0% | 27.8% |
| Central Oregon | 28.1% | 27.6% | 32.5% | 30.1% |
| Southern Oregon | 27.1% | 17.8% | 33.2% | 30.3% |
| Utah | 16.5% | 21.1% | 17.4% | 17.6% |
| Eastern Washington | 21.0% | 21.7% | 25.4% | 23.2% |
| Central Washington | 22.5% | 20.5% | 24.8% | 23.2% |
| SE Washington | 21.0% | 17.6% | 24.3% | 22.5% |
| South Central Washington | 17.8% | 29.1% | 19.9% | 18.7% |
| SW Wyoming | 27.2% | 47.5% | 27.7% | 28.3% |
| Western Wyoming | 47.7% | 47.6% | 48.3% | 47.8% |
| Southern Wyoming | 45.3% | 46.6% | 48.2% | 47.8% |
| SE Wyoming | 45.1% | 35.1% | 47.2% | 46.8% |
| Alberta | 35.1% | 30.1% | 35.1% | 35.0% |
| British Columbia | 29.5% | 30.1% | 31.5% | 30.8% |

Source: Energy Commission staff

**Table 2-8: Henry Hub Natural Gas Index Price $/mmBtu ($2008)**

| Date | $/mmBtu ($2008) |
|---|---|
| 1/1/2012 | 8.13 |
| 2/1/2012 | 7.97 |
| 3/1/2012 | 7.65 |
| 4/1/2012 | 6.97 |
| 5/1/2012 | 6.82 |
| 6/1/2012 | 6.8 |
| 7/1/2012 | 6.97 |
| 8/1/2012 | 6.89 |
| 9/1/2012 | 7.04 |
| 10/1/2012 | 7.26 |
| 11/1/2012 | 7.63 |
| 12/1/2012 | 7.99 |
| 1/1/2016 | 8.06 |
| 2/1/2016 | 7.91 |
| 3/1/2016 | 7.62 |
| 4/1/2016 | 6.96 |
| 5/1/2016 | 6.81 |
| 6/1/2016 | 6.8 |
| 7/1/2016 | 6.96 |
| 8/1/2016 | 6.89 |
| 9/1/2016 | 7.03 |
| 10/1/2016 | 7.25 |
| 11/1/2016 | 7.62 |
| 12/1/2016 | 7.98 |
| 1/1/2020 | 7.3 |
| 2/1/2020 | 7.16 |
| 3/1/2020 | 6.9 |
| 4/1/2020 | 6.3 |
| 5/1/2020 | 6.17 |
| 6/1/2020 | 6.16 |
| 7/1/2020 | 6.3 |
| 8/1/2020 | 6.24 |
| 9/1/2020 | 6.37 |
| 10/1/2020 | 6.57 |
| 11/1/2020 | 6.9 |
| 12/1/2020 | 7.23 |

Source: Ventyx Spring 2008 NERC data release.

**Table 2-9: Rocky Mountain Coal Basin Price $/mmBtu ($2008)**

| Date | $/mmBtu |
|---|---|
| 1/1/2012 | 1.57 |
| 1/1/2016 | 1.61 |
| 1/1/2020 | 1.66 |

Source: Ventyx Spring 2008 NERC data release.

**Table 2-10: Powder River Coal Basin Price $/mmBtu ($2008)**

| Date | $/mmBtu |
|---|---|
| 1/1/2012 | 0.77 |
| 1/1/2016 | 0.87 |
| 1/1/2020 | 0.94 |

Source: Ventyx Spring 2008 NERC data release.

**Table 2-11: Uranium Price $/mmBtu ($2008)**

| Date | $/mmBtu |
|---|---|
| 1/1/2012 | 0.84 |
| 1/1/2016 | 0.93 |
| 1/1/2020 | 0.89 |

Source: Ventyx Spring 2008 NERC data release.