DOCKET
11-IEP-1D
DATE RECD. FEB 24 2011

DRAFT STAFF PAPER

PROPOSED METHOD TO CALCULATE THE AMOUNT OF NEW RENEWABLE GENERATION REQUIRED TO COMPLY WITH POLICY GOALS

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MARCH 2011

CEC-200-2011-001-SD

ACKNOWLEDGEMENTS

The study team for this project includes staff from Electricity Analysis Office, Demand Analysis Office, and Renewable Energy Office at the California Energy Commission. Angela Tanghetti was the primary technical lead for analyzing renewable net short issues, providing estimates of the variables included in the calculations and responsible for the proposed method explained in this staff paper. Karen Griffin provided the summary of the different electricity system studies that apply a renewable net short calculation. Richard Jensen contributed to the comparison of the different renewable net short assumptions and calculated estimates. Linda Kelly characterized the combined heat and power assumptions and discussion of the related uncertainties. Lana Wong was responsible for the discussion on transmission and distribution losses. Chris Kavalec of the Demand Analysis Office was the lead for the electricity demand forecast and discussion of several demand reduction program descriptions. This staff was joined by Pamela Doughman, Rachel Salazar, Mark Kootstra, and Garry O'Neil of the Renewable Energy Office, who provided the characterization of the existing and planned renewable generation resources. Kevin Barker, with Chair Weisenmiller's Office, provided overall guidance and contributions to the renewable resource sections of the paper. Steven Fosnaugh formatted the staff paper and handled the publication logistics.

ABSTRACT

There are numerous challenges to implement renewable policy goals and integrate large amounts of renewable generation into the western electricity grid. Understanding the types, locations, and costs of resources needed to integrate high levels of renewables into the California electricity grid is a complicated and technically challenging task being discussed in multiple forums. Ideally, stakeholders would be able to import the detailed information from one proceeding, such as a renewable environmental assessment, into another proceeding, such as a generation or transmission infrastructure assessments or integration studies. However, this is difficult to do if the studies use different assumptions and calculated estimates of the amounts of renewable generation needed to meet policy goals.

The paper will develop a standard method for calculating the amount of new renewable generation needed to comply with California energy policy goals. The paper also discusses the uncertainties associated with the input variables, noting that incremental renewable generation estimates can differ by the equivalent of almost 10,300 megawatts (MW) of solar-thermal generation capacity. This is a significant deviation when considering electricity system integration requirements and investments. A single method and coordinated approaches for choosing assumptions to promote consistency and simplify an analytical link between the different infrastructure studies will lead to better informed policy development.

Staff wrote this paper in support of the Energy Commission's *2011 Integrated Energy Policy Report*.

Keywords: Renewable, net short, incremental, generation, Renewables Portfolio Standard, Renewable Electricity Standard, electricity, system integration, *2011 Integrated Energy Policy Report*

Please use the following citation for this paper:

Alvarado, Al, Ivin Rhyne. 2010. *Proposed Method to Calculate the Amount of New Renewable Generation Required to Comply With Policy Goals*. California Energy Commission, Electricity Supply Analysis Division. CEC-200-2011-001-SD.

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EXECUTIVE SUMMARY

This staff paper develops a standard method for calculating the *renewable net short* for California load-serving entities and future electricity system infrastructure studies, and to identify a set of information sources and assumptions for the calculation. The renewable net short is the incremental amount of new renewable generation that needs to be added to meet energy policy goals.

Ideally, stakeholders in various forums dealing with resource planning issues would like to be able to import the detailed information from one proceeding, such as a renewable environmental assessment, into another proceeding, such as generation or transmission infrastructure assessments and integration studies. However, this is difficult to do if the studies use different assumptions and estimates of the amounts of renewable generation needed to meet policy goals.

Several studies evaluated the integration requirements for implementing a 33 percent renewable energy generation policy goal in 2009 and 2010. Each of these studies used different accounting conventions and assumptions about the implementation of future load reduction programs to estimate the need for incremental new renewable generation. The renewable net short estimates used in these studies ranged from 45 to 65 terawatt hours (TWh). The difference in these estimates is the equivalent of the potential generation from more than 8,000 megawatts (MW) of solar-thermal or 6,500 MW of wind projects.

There are legitimate reasons for studies to differ, particularly when new information about an input becomes available and thus improves the knowledge base. However, it is important to disclose why certain assumptions were selected or applied, and whether the study is based on publicly reviewed and validated inputs. Developing a standardized approach and set of assumptions to estimate the renewable net short will improve the ability to understand the context for studies and to transfer findings from one research area to another. This will also promote consistency and establish an analytical link between the different infrastructure studies, leading to better informed policy development.

California Energy Commission staff examined the assumptions used to calculate the renewable net short in the different electricity system studies. Some of the renewable net short calculations now have dated assumptions, given the age of the studies. Other studies did not include key variables and policy programs that could reduce electricity retail sales in the future, thereby overstating the amounts of renewable energy needed to satisfy the policy goal. There are also important uncertainties regarding how the variables used for the renewable net short calculation can be measured or assumed to exist in the future. It is important to remember that all values, regardless of the source, are estimates for 10 years into the future.

Energy Commission staff presents a proposed equation and preliminary set of assumptions to use for estimating the renewable net short. The proposed equation for calculating the renewable net short is as follows:

> ***Renewable Net Short (TWh) = ((Projected Retail Electricity Sales – Energy Efficiency Programs – Combined Heat & Power Customer Services – Distributed Generation Additions – Other Demand Reduction Programs) x Policy Goal Percent) – Generation From Existing Eligible Renewable Facilities***

The preliminary set of assumptions that staff uses for the renewable net short calculation are based on the most current electricity system assessments and projections. These inputs and assumptions are not static. They are constantly being revised and updated as new information becomes available. There are numerous studies and proceedings underway that will ultimately update some of the key input assumptions, such as the new electricity demand forecast for the *2011 Integrated Energy Policy Report*. These variables can then be updated to revise the renewable net short estimates.

Applying the staff-proposed equation and preliminary set of input assumptions results in a 33 percent renewable net short by 2020 estimate that ranges between 28.1 TWh to 53.2 TWh. This preliminary renewable net short range has a 25.1 TWh (90 percent) difference, which is the equivalent generation from 10,300 MW of new solar-thermal plants or 8,200 MW of new wind facilities. This range more than encompasses previous estimates of renewable net short mentioned earlier (45 to 65 TWh). Rather than undermine previous estimates, this range illustrates the difficulties inherent in estimating future quantities of generation needs.

Given the resulting range of the calculated renewable net short, it is very important to understand the underlying set of input variables and corresponding array of associated uncertainties. Efforts to resolve the described uncertainties and improve the confidence in selected assumptions will minimize the risks for stranded infrastructure investments, lead to a more realistic measure of resource needs for system reliability and procurement decisions, and ensure that environmental goals are achieved.

Energy Commission staff seek comments on the proposed renewable net short calculations and referenced assumptions.

Definition of the Renewable Net Short

To estimate the amount of renewable capacity that will be built in the coming decade, electricity generation and transmission infrastructure studies must consider what amount of new renewable energy is needed to meet policy goals. This amount of incremental new renewable generation is referred to as the *renewable net short*. Since the Renewables Portfolio Standard (RPS), that was established by legislation in 2002 under Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002) and accelerated in 2006 under Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006), defines the goal amount of renewable energy as a percentage of electricity retail sales, the renewable net short is expressed as the amount of electricity (terawatt hours – TWh) that is generated from renewable generation resources instead of the capacity (megawatt – MW) of these facilities. Since the mandate and regulations specify that retail sales are the basis for establishing the renewable goals, electricity used for water pumping and sources produced for personal consumption (self-generation) are not subject to the requirements.

The proposed equation for estimating the renewable net short is as follows:

> ***Renewable Net Short (TWh) = ((Projected Retail Electricity Sales – Energy Efficiency Programs – Combined Heat & Power Customer Services – Distributed Generation Additions – Other Demand Reduction Programs) x Policy Goal Percent) – Generation from Existing Eligible Renewable Facilities***

The renewable net short metric can be applied to any target year and any renewable energy policy goal. Using the term renewable net short with no additional modifiers provides insufficient information about what is referenced. The more precise way to use this term is to include both the goal percentage and the year under scrutiny; for example, using this approach will distinguish the 20 percent renewable net short estimate in 2010 from the 33 percent renewable net short estimate in 2020. To avoid confusion, this paper will follow the convention of using the term renewable net short as shorthand for referring to the 33 percent renewable net short in 2020 unless otherwise stated.

Study Purpose

This staff paper will develop a standard method for calculating the renewable net short for California load-serving entities and future electricity system infrastructure studies, which includes a set of information sources and assumptions used for the calculation. The renewable net short is the incremental amount of new renewable generation that needs to be added to meet energy policy goals.

Understanding the types, locations, and costs of resources needed to integrate high levels of renewables into the California electricity grid is the subject of studies being conducted in multiple forums. Ideally, stakeholders would like to be able to import the detailed information from one proceeding, such as a renewable environmental assessment, into another proceeding, such as an electricity system infrastructure assessment or renewable generation integration studies. However, this is difficult to do if the studies use different assumptions and estimates of the renewable generation amounts needed to meet policy goals.

Several studies evaluated the integration requirements for implementing a 33 percent renewable energy generation policy goal in 2009 and 2010. Each of these studies used different methods of accounting conventions and assumptions about the implementation of future load reduction programs to estimate the need for incremental new renewable generation. Some of the studies did not include key policy goals and programs that will reduce electricity retail sales in the future, thereby overstating the likely amounts of renewable energy needed to satisfy the policy goal. The renewable net short estimates used in these studies range from 45 TWh to 65 TWh, which is the equivalent of the potential generation from over 8,000 MW solar-thermal or 6,500 MW wind projects. Different, and possibly conflicting, methods create confusion for regulators when making decisions regarding system renewable procurement, establishing transmission requirements, identifying regulation and ramping needs, determining criteria pollutant and greenhouse gas (GHG) emission implications, and considering other infrastructure requirements to ensure electricity system reliability.

There are legitimate reasons for studies to differ, particularly when new information about an input becomes available and thus improves the knowledge base. However, it is important to disclose why certain assumptions were selected or applied, and whether a study is based on publicly reviewed and validated inputs. Developing a standardized approach and set of assumptions to estimate the renewable net short will improve the ability to understand the context for studies and to transfer findings from one research area to another.

The goal for the paper is to develop a single method and coordinated set of assumptions for calculating the renewable net short that will promote consistency and improve analytical links between the different infrastructure studies, leading to better informed policy development. The staff seeks comments on the proposed calculation and input variables information sources that are presented in the paper. The staff also seeks feedback on identified uncertainties associated with the input variables and plausible ranges of assumptions for those variables in the renewable net short calculation.

Comparison of Different Renewable Net Short Studies

A number of recently completed and ongoing studies evaluate the electricity system requirements for implementing the renewable generation policies. The calculation of the renewable net short is a key factor in each of these studies. The resulting renewable net short estimates vary depending on which demand forecast is applied and the consideration of other load reduction measures and policies. Different input assumptions in the various studies result in a range of renewable net short estimates that differ by as much as 45 percent. Conversely, some of these studies derive a very similar renewable net short estimate but calculate the value with different assumptions and methods.

Table 1 and the following section provide a summary of the different studies that include renewable net short estimates. The order of the studies from left to right in **Table 1** is based on the study vintage. **Table 1** also includes an illustrative set of assumptions and renewable net short estimates (Column 7) that are described in this paper.

California Energy Commission Staff Report on *Impacts of AB 32 Scoping Plan Electricity Resource Goals on Natural Gas-Fired Generation* (column 1)*:* Energy Commission staff completed this study for the *2009 Integrated Energy Policy Report (IEPR)*. The study was part of an effort to better understand the electricity system implications of implementing the *AB 32 Scoping Plan* electricity policies, which include the 33 percent renewable goals and other complimentary programs, such as increased energy efficiency investments. This study used the *2007 IEPR* electricity demand and energy efficiency projections since the analysis was initiated early in the proceeding cycle. The electricity demand projection was higher than the adopted *2009 IEPR* forecast, but the assumptions used for the other complementary programs were also higher than current expectations. The 33 percent renewable net short estimate for 2020 was approximately 45.5 TWh, but the vintage of the assumptions used for the study must be considered when this report is referenced.

California Air Resource Board's Impact Assessment of the 33 Percent Renewables Energy Standard (Column 2a, 2b): As part of the regulation development effort, the California Air Resources Board (ARB) assessed the economic impacts of a 33 percent Renewable Electricity Standard (RES).[1] The assessment includes the Energy Commission's *2009 IEPR* demand forecast, plus interagency scenarios of high and low demand. The study also considered high wind and solar generation scenarios to determine a range of impacts. This study was completed in June 2010 as part of the rule-making package for the Office of Administrative

1 Governor Schwarzenegger directed the CARB (Executive Order S-21-09) to adopt a regulation by July 31, 2010, requiring the state's load serving entities to meet a 33 percent renewable energy target by 2020, which is referred to as the Renewable Electricity Standard.

Law. The renewable net short estimates for 2020 that were included in the study ranged between 53.6 TWh and 66.1 TWh.

California Independent System Operator and California Public Utilities Commission 33 Percent Renewables Operational Study (Column 3): The study was to determine the generation resources needed to integrate various scenarios of 33 percent renewables into a reliable California grid, assuming that many of the renewables will be variable wind or solar. This study was managed by California Independent System Operator (California ISO) and included contributions from an interagency Energy Working Group. The study was intended to feed into developing the ARB RES. The assumptions used for the renewable net short estimate were established in 2010 and include the *2009 IEPR* demand forecast, but not other assumptions about policies intended to reduce load. The study was provided to the California Public Utility Commission (CPUC) as background for the Long Term Procurement Proceeding (LTPP). The study focused on the need for conventional generation under many weather, seasonal load, and renewable supply variations. The study included a 64.1 TWh renewable net short estimate.

Renewable Energy Transmission Initiative – RETI (Column 4): The Renewable Energy Transmission Initiative (RETI) stakeholder group developed a renewable net short estimate in 2010. The stakeholder members used the *2009 IEPR* demand forecast for the calculation. The analysis did not include other policy programs such as energy efficiency and rooftop photovoltaic goals, which reduce retail electricity sales. The existing renewable generation value was also higher than the values used in other studies because estimates of generation from new facilities under construction were added to the calculation. The RETI assumptions are being used for the California Transmission Planning Group that is preparing the filings to comply with the Federal Energy Regulatory Commission (FERC) Order 890 requirements. The renewable net short estimate used for the RETI studies is about 52.8 TWh.

Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC) Renewables Net Short Estimate (Column 5a, 5b): TEPPC is compiling a WECC-wide data set for use in transmission expansion planning studies for the West. As part of this effort, the working group is developing renewable scenarios with specified amounts for each state. The working group reference case for California was developed in 2010 and included a 65.2 TWh renewable net short estimate. Energy Commission and CPUC staff has developed a mid-point case, which includes assumptions about incremental energy efficiency and combined heat and power. The mid-range load reduction assumptions results in a 56.4 TWh renewable net short.

California Public Utilities Commission 2010 Long Term Procurement Proceeding – LTPP (Column 6): The CPUC staff developed requirements for multiple scenarios and estimates of renewables net short that the utilities must use for their 2010 LTPP filing in 2011. The scenarios include incremental amounts of energy efficiency and other load reduction programs. Both utilities and stakeholders may propose other scenarios, including different demand levels or program accomplishments. The scenario proposals are based on a series of

studies, modified by utility-specific information. Energy Commission and CPUC staff worked on the detailed method for computing a renewable net short and refining a common method.

Table 1: Comparison of 33 Percent Renewable Net Short Calculations Used in Different Electricity Infrastructure Studies

			1	2a	2b	3	4	5a	5b	6	7
	All Values in TWh for the Year 2020	**Formula**	**CEC IEPR 09 Impact of AB32**	**ARB 33% RES - Low Load**	**ARB 33% RES - High Load**	**CAISO/CPUC 33% Integration Study**	**RETI CTPG**	**WECC TEPPC Reference Case**	**WECC TEPPC State Adjusted**	**CPUC 2010 LTPP**	**CEC Staff Illustrative Example RNS Estimate**
1	Net Energy For Load		341.8					326.5	328.2		
2	Statewide Total Deliveries (Retail Sales)		320.4	303.3	303.3	301.4	300.1	303.7	305.2	303.3	303.3
3	Non RPS Deliveries (CDWR, WAPA, MWD)		12.3	4.5	4.5	12.3	13.6	13.6	13.6	13.6	13.6
4	Small LSE Sales (<200 GWh)		0.0	0.0	0.0	0.0	0.0	2.3	2.3	2.3	2.3
5	Retail Sales for RPS	5=2-3-4	308.1	298.8	298.8	289.1	285.7	287.8	289.4	287.4	287.4
6	Additional Energy Efficiency		34.7	22.0	0.0	0.0	0.0	0.0	19.4	17.0	17.1
7	Additonal Combined Heat and Power		32.3	14.0	0.0	0.0	0.0	0.0	7.0	7.6	7.2
8	Additional Rooftop PV		4.8	2.0	0.0	0.0	0.0	0.0	1.8	0.0	1.9
9	**Adjusted Statewide Retail Sales for RPS**	9=5-6-7-8	236.3	260.8	298.8	289.1	285.7	287.8	261.3	263.0	261.2
	Existing Renewable Generation										
10	Total Instate Renewable Generation		29.8	28.8	28.8	28.8	39.4	29.8	29.8	29.8	34.3
11	Out of State Claims		2.7	3.7	3.7	2.5	2.1	0.0	0.0	2.8	9.2
12	**Total Existing Renewable Generation for CA RPS**	**12=10+11**	**32.5**	**32.5**	**32.5**	**31.3**	**41.5**	**29.8**	**29.8**	**32.6**	**43.5**
13	**Total RE Net Short to meet 33% RPS In 2020**	**13=(9*33%)-12**	**45.5**	**53.6**	**66.1**	**64.1**	**52.8**	**65.2**	**56.4**	**54.2**	**42.7**

Source: Energy Commission staff.

Column 1: CEC IEPR 09 Impact of AB32 - http://www.energy.ca.gov/2009publications/CEC-200-2009-011/CEC-200-2009-011.PDF

Column 2a and 2b: ARB 33 percent RES - http://www.arb.ca.gov/energy/res/meetings/040510/e3-presentation.pdf The final version of the RES calculator was prepared by Joseph Fisher jofische@arb.ca.gov of ARB staff but not posted to the ARB website.

Column 3: CAISO/CPUC 33 percent RPS Integration Study- Renewable Net Short Forecast based on High Load Case work papers provided during work group meeting March 10, 2010

Column 4: RETI/CTPG - http://www.ctpg.us/public/images/stories/downloads/2011-01-04_DRAFT_StatewideTransmissionPlan.pdf See Table 1.

Column 5a and 5b: WECC TEPPC Reference and State Adjusted – contact Angela Tanghetti at atanghet@energy.state.ca.us for WECC Studies Work Group working papers.

Column 6: CPUC 2010 LTTP - http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm

Key Variables and Uncertainties That Affect the Renewable Net Short Calculation

Anything that reduces electricity retail sales (energy efficiency program savings, rooftop solar photovoltaics, and other customer-side-of-the-meter distributed generation) will reduce the renewable requirement. Estimates of the renewable net short will also change over time as forecasts of electricity demand in the policy target year change. This has been noticeable in the last several years as forecasts include the effects of the economic downturn and consider the possible timing of a rebound. Similarly, the uncertainties of meeting the state goals for energy efficiency, combined heat and power (CHP), and rooftop solar will affect the amount of renewable energy ultimately needed.

The need for renewable generation additions to meet policy goals will also depend on how much renewable power is already flowing into the system. Estimates of existing renewable generation will vary depending on the vintage of the estimate, the amount of out-of-state renewable generation attributed to utilities, and the amount of renewable generation not claimed as eligible for the RPS that is included in the estimate. The amount of electricity produced from renewable generation facilities may also fluctuate depending on weather conditions, such as the persistence of wind or precipitation over the year. The wide variation between estimates illustrates the need for common assumptions and counting conventions so that the public can be confident in both the goals and reported progress.

The key variables critical to calculate the renewable net short are defined in the RPS legislation and RES, but a precise method on how to estimate these variables is not explicitly defined. It is important to remember that all values, regardless of the source, are projections into the future. All future supply and demand estimates are subject to a degree of uncertainty that may affect the trajectories of policy programs and intended infrastructure investments. For example, the expected electricity demand reductions from energy efficiency programs may vary between 15.2 TWh to 19.9 TWh by 2020, depending on the level of expected expenditures and changes to consumptions behavior patterns.

Prudent consideration of these kinds of uncertainties should be applied to renewable net short calculations and infrastructure studies. The use of a single-point forecast will not reveal potential economic and system reliability risks of an infrastructure investment decision. Allowing for a relevant range of possible future scenarios will result in an array of outcomes for calculating retail electricity sales and the renewable net short goal. There are numerous studies and proceedings underway that will ultimately update some of the key input assumptions and address relevant uncertainties, such as the updated electricity demand forecast for the *2011 IEPR*, so the calculated net short may change with time.

Each of the elements of the renewable net short calculation has contributing sources and uncertainty factors that will be explored in this section, organized as follows:

- Projected Retail Electricity Sales
  - Retail Sales From California Energy Demand Forecast
  - Treatment of Transmission and Distribution Losses
- Demand Reduction Programs
  - Energy Efficiency Impacts
  - Incremental Distributed Generation Goals
  - Incremental Combined Heat and Power
- Generation From Existing Eligible Renewable Facilities
  - Estimating Existing Renewable Generation

Projected Retail Electricity Sales

Projected retail sales are the building block on which the calculation of renewable goals and renewable net short is based. Energy Commission staff develops a full statewide energy and peak demand electricity forecast every two years for the biennial *IEPR* report, which is the appropriate starting point for calculating the renewable net short. This forecast, known as the *California Energy Demand Forecast (CED)*, includes estimates of demand reductions, such as energy efficiency and self-generation. The *CED* includes an assessment of eight transmission planning areas, which include:

- Burbank/Glendale
- Imperial Irrigation District
- Los Angeles Department of Water and Power
- Pacific Gas and Electric
- Pasadena
- Sacramento Municipal Utility District
- San Diego Gas & Electric
- Southern California Edison

Different models[2] are used to project total electricity consumption by end users for each of these California planning areas. Output from the models is calibrated to match historical

2 Separate models are employed for the residential, commercial, industrial, agricultural, and transportation, communication, and utility sectors.

consumption in each sector, equal to retail sales plus private electricity supply provided to end users.[3] Projected consumption by electric vehicles, provided by the Energy Commission's Fuels Office, is also incorporated into the forecast.

Retail Sales From California Energy Demand Forecast

Forecast retail electricity sales are calculated in the *CED* by subtracting projected private supply consumed on-site from projected consumption. The forecasts for consumption and retail sales represent the customer side of the meter and are therefore net of transmission and distribution losses. Staff adds these losses back in when estimating net energy for load (energy that needs to be produced by generators to meet demand), using loss factors provided by the utilities.

Retail electricity sales projected in this manner reflect supply provided by load-serving entities located in control areas within California, and the resulting statewide sales figure is the value most commonly reported by the Energy Commission. However, a small amount of electricity is provided to California from entities outside the state. Therefore, staff also projects sales to California from these out-of-state entities, which allows for a forecast of *all* electricity sales within the state.[4]

The key drivers for the electricity retail sales forecast remain population, household, and economic growth. To illustrate, the *2007 IEPR* demand forecast, with relatively optimistic assumptions regarding economic growth, projected statewide electricity sales of approximately 314 TWh in 2020. In the *2009 IEPR* forecast, incorporating the recent recession and more pessimistic economic growth assumptions, projected statewide sales in 2020 fell to approximately 301 TWh. Without the consumption by electric vehicles, included in the 2009 CED and not in the 2007 forecast, projected 2020 retail sales in the *2009 IEPR* forecast declined to approximately 297 TWh.

Current economic projections for California are even more pessimistic than those used in the *2009 IEPR*, so the *2011 IEPR* electricity sales forecast for 2020 could be significantly

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3 Large self-generators report directly to the Energy Commission and utilities report estimates of aggregate smaller-scale self generation as part of routine Quarterly Fuel and Energy Reports submissions. Additional self-generation installations are reported through incentive programs such as the California Solar Initiative and the New Solar Homes Partnership.

4 Projections of sales to California customers from load-serving entities in control areas within the state are provided in *Statewide Form 1.1b*, while projections for all sales to California customers are provided in *Statewide Form 1.1c.* These and other forms for the *2009 IEPR* forecast are available on the Energy Commission's website: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html.

below the *2009 IEPR* figure. However, economic growth remains highly uncertain, and conditions could improve markedly within the next few months.

For the *2009 IEPR*, staff developed alternative forecasts using more optimistic and pessimistic economic projections than used in the base case forecast, and will provide similar analysis for the *2011 IEPR*. The *2009 CED* electricity retail sales projection for the California load serving entities is 303.3 TWh by 2020[5]. The *CED* alters the projection by 2.3 percent for a high case and -1.9 percent for the low end of the range[6]. The resulting electricity sales range is 297.5 TWh to 310.3 TWh for 2020.

All California load-serving entities with retail electricity sales greater than 200 GWh are subject to the 33 percent RES. Out-of-state utilities that serve some customers in California still have the same California RES and RPS obligation.

The statewide retail electricity sales projection includes water delivery agencies and smaller load serving entities with annual sales less than 200 GWh, which must be subtracted for the renewable net short calculation. Statewide Form 1.1c in the *CED* specifically identifies the amount of retail electricity sales included in the demand forecast for the water pumping agencies (MWD, CDWR and WAPA). This form also lists the load-serving entities with annual retail sales less than 200 GWh.

Table 2 summarizes the values described above. The adjusted range of electricity retail sales for 2020 is 281.6 TWh to 294.4 TWh, which will be used for as part of the renewable net short estimate presented later in the report. The Base Case electricity retail sales value is used for the mid-range set of assumptions and renewable net short estimate.

Table 2: Range of Retail Sales in 2020 for Use in Renewable Net Short Calculations

	Low Sales Alternative	Base Case	High Sales Alternative
Total Retail Electricity Sales (2020)	297.5	303.3	310.2
Pumping Loads and Small Utility Exclusion	15.9	15.9	15.9
Retail Sales Subject to 33% RES	281.6	287.4	294.4

Source: Energy Commission staff.

5 Projections for all sales to California customers are provided in *Statewide Form 1.1c.* These and other forms for the *2009 IEPR* forecast are available on the Energy Commission's website: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html.

6 Kavalec, Chris, Tom Gorin. 2009. *California Energy Demand 2010-2020, Adopted Demand Forecast*, CEC-200-2009-012-CMF. Page 6.

The retail electricity sales assumption will change once the updated *CED* is reviewed and adopted for the *2011 IEPR*.

Treatment of Transmission and Distribution Losses

California's 20 percent RPS and 33 percent RES both utilize the same metrics for defining the amount of renewable energy that must be procured. The policies require that utilities procure an amount of generation *equal* to a percentage of retail sales, not the amount of generation needed to cover the associated losses for delivering the electricity to a consumer. The associated transmission and distribution losses are ignored under the current renewable policy goals.

The Energy Commission's forecast of retail electricity sales represents the customer side of the meter and is therefore energy after transmission and distribution losses. The Energy Commission also prepares a forecast of energy needed to be produced by generators, called *net energy for load*, which includes both end-use energy consumption and system losses between the generator and the end user.

Some analysts use the net energy for load forecast instead of the retail electricity sales projections for the renewable net short calculations. Net energy for load is used by WECC since retail electricity sales are not calculated in a consistent manner between all members. A transmission and distribution loss factor is then applied for the renewable net short calculation for the WECC assessment.

Table 3 presents the loss factors used in the *2009 California Energy Demand 2010-2020, Adopted Forecast*, December 2009.

Table 3: Loss Factors Included in the Net Peak and Net Energy for Load Tables

	Peak	Energy
PG&E	1.097	1.096
SMUD	1.077	1.064
SCE	1.076	1.068
LADWP	1.112	1.135
SDG&E	1.096	1.0709
Burbank, Glendale, Pasadena	1.051	1.064
IID	1.06	1.128
DWR	1.06	1.038

Source: California Energy Demand 2010 – 2020.

The difference between the CED net energy for load forecast (326.9 TWh) and retail electricity sales (303.3 TWh)[7] implies a 1.078 (7.8 percent) transmission and distribution loss factor. This loss factor should be applied if a net energy for load forecast is used for a California renewable net short calculation. If any additional load reduction programs are included in a renewable net short calculation, losses associated with these programs should not be included.

Demand Reduction Programs

There are other demand reduction policy goals and an expectation that some progress towards those goals will likely occur. These additional programs are *not* included in the *California Energy Demand* forecast and must be considered as an adjustment to the electricity retail sales estimate for the renewable net short calculation. Other programs to consider include uncommitted energy efficiency programs, self-generation additions, incremental distributed generation goals, and the combined heat and power policy goals.

Energy Efficiency Impacts

Not all load reductions expected to occur or required by policy are included in the Energy Commission retail electricity sales forecast. As in the case of retail electricity sales, energy efficiency impacts estimated for and incorporated in the IEPR demand forecast reflect the customer side of the meter. The inclusion of energy efficiency impacts in the renewable net short calculation indicates that it is reasonable to expect energy efficiency savings beyond what is already embedded in the IEPR demand forecast.

The demand forecast includes estimated historical and projected savings from *committed* efficiency initiatives, which consist of utility and public agency programs, codes and standards, and legislation and ordinances that have final authorization, firm funding, and a design that can be readily translated into characteristics that can be evaluated and used to estimate future impacts. The *2009 IEPR* forecast incorporated committed utility efficiency programs through 2012 (the end of the current three-year CPUC program cycle) for the investor-owned utilities (IOUs) and through 2009 for publicly owned utilities (POUs), along with codes and standards implemented through 2005.

At the time of any *IEPR* forecast, there are also potential efficiency impacts from future initiatives that are less firm, yet still reasonably likely. Examples in the case of the *2009 IEPR* process include IOU efficiency programs beyond 2012 and Assembly Bill 1109 (Huffman,

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7 Forms 1.2 and 1.1c respectively from the *2009IEPR* Demand Forecast can be found at the Energy Commission's website: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html.

Chapter 534, Statutes of 2007). Impacts from these initiatives are referred to as *uncommitted* energy efficiency. Beginning with the *2009 IEPR*, staff estimates potential uncommitted efficiency impacts that are *incremental* to committed impacts incorporated in the demand forecast. In the *2009 IEPR* analysis, high-, medium-, and low-goal scenarios for uncommitted efficiency were examined.[8] This work included IOU service territories only; for the *2011 IEPR* forecast, staff plans to expand the analysis to non-IOU areas. Energy Commission staff recommends that the range of uncommitted energy efficiency estimates that are reported in each *IEPR* be used for the calculating the renewable net short.

For the three major IOUs combined, estimated incremental energy savings in 2020 total between 10.7 TWh and 14.4 TWh.[9] An additional 1.9 TWh[10] are added to the savings to capture the CPUC directives that require IOUs to replace 50 percent of program savings that decay as efficiency measures wear out, starting in 2006.

Since the uncommitted energy efficiency scenarios did not include estimates for the POUs, a ratio of the utility retail electricity sales is applied. The IOU retail electricity sales represent about 75 percent[11] of the statewide forecast of consumption, and POUs cover the remaining 25 percent. Applying the POU sales ratio to the uncommitted energy efficiency scenario goals provides a range between 2.7 TWh and 3.6 TWh.

The proposed range of uncommitted energy efficiency for both the IOU and POUs are:

- Low Range = 10.7 TWh + 1.9 TWh + 2.7 TWh = 15.2 TWh.
- Mid Range = 12.2 TWh + 1.9 TWh + 3.1 TWh = 17.1 TWh.
- High Range = 14.4 TWh + 1.9 TWh + 3.6 TWh = 19.9 TWh.

These uncommitted energy efficiency forecasts represent a decline in consumption and are already adjusted for losses. If an uncommitted energy efficiency forecast includes losses, the estimates must be adjusted for the renewable net short calculation.

Forecasts of uncommitted energy efficiency impacts are subject to a great deal of uncertainty, given lack of firm funding. Estimates of committed utility program net impacts, both historical and projected, are also fairly uncertain. For example, efficiency measures

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8 The uncommitted efficiency report is available at http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html.

9 *Incremental Impacts of Energy Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast,* Table 1, page 2.

10 *Ibid,* page 4.

11*Ibid,* page 4.

might be purchased but not installed, or may not perform as expected. The most recent CPUC Evaluation Measurement &Verification study,[12] for 2006–2008 IOU programs found utility-reported savings to be overstated. In fact, the study found that net-to-gross ratios and realization rates (which adjust the reported savings) were lower than assumed in the *2009 IEPR* forecast, so that program impacts may be overstated in the forecast. Staff estimates that replacing the *2009 IEPR* forecast adjustment rates with the lower percentages estimated in the CPUC study during the forecast period would reduce projected IOU program savings by over 2,000 GWh in 2020.

Since the *2009 IEPR* forecast relied on adjusted utility-reported savings to develop projected impacts through 2020, this means that program impacts may be overstated in the forecast. In the case of codes and standards, the primary source of uncertainty comes from compliance rates, for which very little empirical data are available.

Staff believes that it is appropriate to include some amount of incremental energy efficiency measures beyond those embedded in the *IEPR* demand forecast. Staff proposes that the number used in a renewable net short calculation should be the mid-case (17.1 TWh) incremental energy efficiency forecast.

Incremental Distributed Generation Goals

The demand forecast sector models are used by staff to project electricity consumption on the customer side of the meter. Forecasted retail sales are then calculated by subtracting projected private electricity supply consumed on-site (self-generation) from projected consumption. In general, projected self-generation is developed by trend analysis and then included in the IEPR demand forecast. Including any value of distributed generation (DG) in the renewable net short calculation is done if it is prudent to plan on more distributed generation than is already included in the IEPR demand forecast.

DG can be categorized two ways, self-generation and wholesale distributed generation. Self-generation is produced on site by consumers for their own use, while wholesale DG is a small generating station meant to serve electrical load elsewhere on the system. New self-generation from a DG project affects the calculation of renewable net short differently than wholesale DG. New self-generation DG will reduce projected retail sales by the amount of generation. Wholesale DG is sold into the electricity market instead of being used to serve the on-site electricity needs. The primary self-generation DG supply considered for the renewable net short calculation is the amount of electricity expected from small scale rooftop photovoltaic (PV) systems.

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12 http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/2006-2008+Energy+Efficiency+Evaluation+Report.htm.

The California Global Warming Solutions Act (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006). The act requires the California Air Resources Board (ARB) to develop regulations and market mechanisms that will reduce California's greenhouse gas (GHG) emissions by 25 percent by 2020. On December 11, 2008, the ARB issued a *Scoping Plan* for the implementation of AB 32.The *Scoping Plan* calls for 3,000 MW [13] of additional self-generation rooftop PV beyond what was identified in the *2007 IEPR CED* forecast. To use this in a renewable net short calculation, the *AB 32 Scoping Plan* rooftop PV capacity goal must be converted into an energy forecast. The *Scoping Plan* includes an assumption that the rooftop PV will operate at a 17 percent capacity factor,[14] resulting in an energy goal of 4.5 TWh of self-generation electricity in 2020. New rooftop PV has been built since 2007 and adjusted in the *2009 IEPR CED* demand forecast, and more will likely be included in the upcoming forecast. The *Scoping Plan* rooftop PV energy goal must thereby be adjusted down by 2.6 TWh to account for the differences between the *2007 CED* and the *2009 CED*. The remaining amount of rooftop PV needed to meet the *AB 32 Scoping Plan* goal is estimated to be 1.9 TWh.

The *California Clean Energy Future* sets a new goal of 5,000 MW by 2020 for renewable distributed generation.[15] This goal is expected to be met or exceeded through a combination of the following programs:

- 3,000 MW of self-generation DG PV through the programs associated with Senate Bill 1 (Murray, Chapter 132, Statutes of 2006).
- 500 MW of wholesale generation DG PV through PG&E (half of the MW will be utility-owned; half will be provided by independent energy producers).
- 500 MW of wholesale generation DG PV through SCE (half of the MW will be utility-owned; half will be provided by independent energy producers).
- 100 MW of proposed wholesale generation DG PV through SDG&E (26 MW will be utility-owned; 74 MW will be provided by independent energy producers).
- 750 MW of wholesale generation (including non-PV DG, per SB 32) from existing feed-in tariff.
- 1,000 MW of wholesale generation (including non-PV DG) for the Renewable Auction Mechanism (RAM) decision that was adopted by the CPUC.[16]

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13 *Climate Change Proposed Scoping Plan Appendices, Volume I: Supporting Documents and Measure Detail*, Page C-121.

14 CPUC, *California Solar Initiative, 2009 Impact Evaluation*, Final Report. The average capacity factor of all systems that received Expected Performance Based Buydown funding was 19.2 percent.

15 *California's Clean Energy Future - An Overview on Meeting California's Energy and Environmental Goals in the Electric Power Sector in 2020 and Beyond*, *http://www.cacleanenergyfuture.org/2821/282190a82f940.pdf*

It is unclear to staff at this time how these new goals will translate into specific savings in 2020. As a result, staff seeks input from stakeholders on what amount of these additional goals should be translated into assumed reductions in load for planning purposes. Given the combined *AB 32 Scoping Plan* goals as well as the *California Clean Energy Future* goals, it is appropriate to assume 1.9 TWh of savings from incremental DG in the renewable net short calculation. However, staff also believes that this number will need to be carefully reviewed and revised each time the renewable net short is calculated.

Incremental Combined Heat and Power

Combined heat and power (CHP) projects are a specific type of distributed generation project that combines elements of both self-generation and wholesale DG. CHP will reduce the need for an industrial customer to purchase electricity, thereby affecting the retail electricity sales forecast. Some amount of CHP is already calculated within the IEPR demand forecast using the trend analysis method mentioned in the previous section. Any number selected for use in a renewable net short calculation will be in addition to the amount already embedded in the *IEPR* demand forecast.

To estimate the amount of CHP incremental to the demand forecast, it is necessary to look for changes in the business landscape for CHP that will push development beyond the "current trend" estimates. There are a number of studies that evaluate the technical and market potential for new CHP in California. Policy goals and regulations are under development to encourage the penetration of CHP projects. CHP policy initiatives are still in the formative stage, so estimated amounts of on-site CHP that should be subtracted from the retail electricity sales forecast are very uncertain. Furthermore, the current CHP estimates do not use a common accounting convention for measuring existing generation, what amounts of generation may shut down, or what kind of projects may be economically feasible for future industrial and commercial development.

A 2009 market assessment report[17] provided an inventory of existing CHP capacity, as well as estimates of technical and market potential for new CHP in California that took into account the AB 32 mandates. The ARB Scoping Plan states, "The widespread development of efficient CHP systems would help displace the need to develop new, or expand existing power plants. This measure sets a goal of an additional 4,000 MW of installed CHP capacity by 2020, enough to displace approximately 30 TWh of demand from other power generation sources."[18] Additionally, the ARB plan assumed that a substantial portion of the operational

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16 For more information, please see:
http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm

17 ICF International, Inc., prepared the Public Interest Energy Research (PIER) final project report *Combined Heat and Power Market Assessment*, CEC-500-2009-094, in October 2009.

18 ARB Scoping Plan, pp. 42-43.

CHP (projects developed under the Public Utility Regulatory Policies Act of 1978**,** termed qualifying facilities – QFs) in California would continue to operate.

In May 2009, the CPUC, the three major IOUs in the state, the Independent Energy Producers Association, the Cogeneration Association of California, the Energy Producers and Users Coalition representing the major CHP operators and developers in California, along with the Division of Ratepayer Advocates and the Utility Reform Network, agreed to a settlement to resolve a number of existing disputes, as well as future issues associated with qualified facility (QF) contracts. One of the goals of the settlement is to assure that existing QFs would be able to secure new contracts and to continue to operate. The three IOUs will be required to procure a minimum of 3,000 MWs of CHP, which is the number of existing QF contracts that are expected to expire in the short term, and any additional CHP that may be necessary to meet the ARB GHG emission reductions goals (estimated at 4.3 million metric tons [MMT]). The settlement also supports and recommends proportional MW goals and GHG reduction goals (estimated 1.9 MMT)[19] for all POUs in California at ARB and in other statewide or national venues.

The IOUs have submitted the settlement to Federal Energy Regulatory Commission (FERC) for final approval, and a decision is expected by May 2011. If the settlement is approved, new opportunities will emerge to stimulate large baseload CHP development, but the needs and opportunities for expanding the market for small CHP projects that are less than 20 MW, and often under 5 MW, are still very limited. The *2009 Market Assessment Report* estimated that more than 3,000 MW of small CHP could be developed in California, but barriers like unfavorable utility tariffs related to supplemental, standby, and backup power and uncertainty associated with air quality and GHG cap and trade regulations still keep CHP developers on the sidelines. Growth in this sector may remain slow for the foreseeable future.

For the interim, Energy Commission staff includes a range of possible CHP additions for the renewable net short calculations based on the *AB 32 Scoping Plan* and the *2009 Market Assessment Report*. The *AB 32 Scoping Plan* includes a 4,000 MW target that will be sold to the grid, which will not reduce retail sales and affect the renewable net short calculation. The *2009 Market Assessment Report* includes a range of incremental CHP capacity from 2,259 MW to 5,532 MW, with the amount serving the customer side of the meter ranging up to 90 percent which would affect the renewable net short. The capacity factors for the demand-side CHP contributions range from 73.8 percent (ICF *Base Case*) to 81.6 percent (ICF *All-In Case*).

Considering each of these factors, the range of incremental CHP energy to be included in the preliminary renewable net short calculation is between 0 TWh and 19.8 TWh. The lower bound represents the possibility that all of the CHP generation will be sold to the grid or

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19 CHP Program Settlement Agreement Term Sheet. October 1, 2010. Section 6.3.4, 6.3.5, p 32.

replacing existing facilities and will not affect the renewable net short. The higher bound captures the possibility of greater CHP development levels and increasing amounts of the generation serving owner loads to reduce overall retail electricity sales in California.

With the approval of the settlement agreement by the CPUC in December and the strong likelihood that FERC will also approve the settlement in May 2011, staff recommends using some of the outcomes presented for the *All-In Case* in the *2009 Market Assessment Report.* The staff recommends using a 50/50 split assumption for the amount of CHP generation that is sold to the grid and what is consumed on site. Within these bounds, staff recommends using a CHP value of 7.2 TWh as a mid-range assumption for the renewable net short calculation. This value includes Governor Brown's goal for 6,500 MW of new CHP development within 20 years that is contained in his Clean Energy Jobs Plan.[20]

As with all the values in this paper, staff seeks input from stakeholders as to the appropriateness of using such a low value for this calculation. Staff also reemphasizes that this assumption will need to be carefully reviewed each time the renewable net short calculation is updated.

Estimating Existing Eligible Renewable Generation

To estimate the additional or net renewable energy needed to meet policy goals, renewable generation currently in place and expected to be operational for California retail electricity sales in the target year both in- and out-of-state must be considered. New generation is added each year or procured under contract but also fluctuates depending on whether there are favorable weather conditions to maximize the amounts of electricity produced by wind or solar.

There are two theoretical approaches to estimating "existing generation" data. The first is to use the most recent actual generation data, which has been the practice to date. This energy data approach has the strength of bypassing the possibility of "gaming" by participants who may try to overstate capacity. The weakness of this approach is that generation from variable resources, such as small hydro and wind, will fluctuate in any given year and is more correlated with atmospheric factors than with installed capacity. The second approach is to use the installed generation capacity of renewables and convert that to an expected amount of energy generated in the target year using some fixed planning assumption for generation (for example, a capacity factor of 32 percent for all wind sources multiplied by the nameplate capacity of wind generation in California). This approach depends less on annual weather variations.

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20 http://www.jerrybrown.org/jobs-california%E2%80%99s-future

Both approaches suffer from a lack of transparency and predictability in the amount of renewable generation that can be expected from out-of-state renewable imports. Each is discussed in more detail below.

Using Energy Data to Estimate Existing Renewable Generation

In the past, the "existing generation" number was based on the generation data reported in the *Net System Power Report* that the Energy Commission prepared each year to comply with the Power Source Disclosure Program (PSDP) requirements.[21] The *Net System Power Report* included the Quarterly Fuels and Energy Reporting (QFER) data reported to the Energy Commission every June for the previous year's generation totals on a facility-by-facility basis. The *Net System Power Report* requirement was discontinued by the Legislature, and 2009 was the last year the report was published. Generators are still mandated to report their generation under QFER, and a summary is periodically updated on the Energy Commission's website.[22]

California generators provide fuel and energy data for their specific plants. Retail electricity providers provide information on the energy they procure on the open market. Purchases of energy on the market (as opposed to energy produced at a facility) are quantified as either "claimed" or "unclaimed" purchases[23] and further distinguished by whether they are from in-state sources or out-of-state imports.[24] For in-state purchases, the status of claimed versus unclaimed is not critical since it is assumed that California will continue to be a net importer of renewable energy for the foreseeable future. This means that any renewable energy produced in California is assumed to be consumed in California.

For out-of-state renewable energy, the distinction of claimed versus unclaimed raises an issue that must be resolved when examining the data. Three different approaches to combining in-state with out-of-state existing generation data are as follows:

- Total renewable generation, both claimed and unclaimed, for in-state and out-of-state renewables

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21 California Energy Commission. *2008 Net System Power Report*. Publication Number CEC-200-2009-101-CMF. June 2009.

22 http://energyalmanac.ca.gov/electricity/ELECTRICITY_GEN_1997-2009.XLS.

23 Claims, or specific purchases, are defined by law as "electricity transactions which are traceable to specific generation sources by an auditable contract trail or equivalent, such as a tradable commodity system, that provides commercial verification that the electricity source claimed has been sold once and only once to a retail consumer."

24 Net electricity imports are based on metered power flows between California and out-of-state balancing authorities.

- Only specified claims for in-state and out-of-state renewables
- Or a hybrid method of these two: total renewable generation for in-state renewables and only specified claims for out-of-state.

The first method relies solely on the total system power[25] calculation. This calculation has two components, in-state generation and net electricity imports. The in-state generation component uses generation reported under the QFER requirements. The out-of-state import component uses metered power flows between California and adjoining balancing authorities. "The electricity import values are not precise because there is no data tracking system available to identify the source of the generation associated with wholesale market transactions and interstate power flows."[26]

The second method relies on specific purchase claims by in-state retail electricity sellers. In-state electricity retailers are required to participate in the PSDProgram, in which they can claim specific purchases that make up their power mix. Under the current program, retailers could choose not to disclose their specific purchases and claim a generic resource mix for those purchases. Proposed changes to the program would require retailers who make specific purchases to disclose those purchases in an annual filing. However, spot market, or other non-traceable purchases, will still be unspecified, and therefore, any unclaimed in-state renewables will not be accounted for in this method.

The third method relies on QFER data for in-state renewables and specific purchases for out-of-state renewables. For this method, staff assumes that most of the renewables identified in the QFER dataset would likely meet California's RPS eligibility requirements. Most investor-owned utilities have made great strides to claim all their contracted renewable purchases. However, some publicly owned utilities may not claim individual renewable purchases in their power source disclosure filings. Hence, these unclaimed facilities may make up the difference between in-state total system power and claimed power.

Energy Commission staff assumes that this power is derived from renewable facilities that are eligible for the RPS. Conversely, out-of-state "renewable" power may be eligible and used for other state mandated renewable standards, and therefore would not be eligible (or

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25 Total system power is the sum of all in-state generation and net electricity imports by fuel type. All generators that are 1 megawatt (MW) or larger in California report actual generation and fuel use to the Energy Commission under the Quarterly Fuels and Energy Reporting requirements. The California control areas or balancing authorities report metered power flows on the main transmission lines that are used to represent electricity imports.

26 Nyberg, Michael, 2009. *2008 Net System Power Report*. California Energy Commission. CEC-200-2009-010.

available) for California's RPS. To avoid double counting and exclude power that is not eligible in the "existing generation" value, only out-of-state claims are used. For example, **Table 4** shows the 2008 "existing generation" value used by Energy Commission staff is 31.3 TWh.

Table 4: 2008 Existing Generation[27] (TWh)

	Total System Power	Claims Only	Hybrid
Total System Power In-state Renewables	**28.8**	**28 .0**	**28.8**
Estimated Renewable Imports from Northwest	**2.3**	**1.7**	**1.7**
Estimated Renewable Imports from Southwest	**1.4**	**0.7**	**0.7**
Total	**32.5**	**30.5**	**31.3**

Source: Nyberg, Michael. 2009. *2008 Net System Power Report*. California Energy Commission. CEC-200-2009-010.

Using previous year generation data can potentially reflect drastic shifts from high to low generation years based on weather conditions in a given year. The use of tradable renewable energy credits may also vary independently of the amount of renewable capacity on-line. Furthermore, estimates of the annual generation will depend on how many facilities came on-line, when they came on-line, and if there are any unusually long maintenance periods for the existing facilities.

Hydroelectricity generation correlates directly with annual rainfall, which also varies from year to year. According to the California Power Plant Database, there is roughly 1,500 MW of small hydro (< 30 MW) in California.[28] Although the small hydro capacity has remained unchanged since 2004, annual generation has fluctuated greatly. For example, in 2006 and 2007, total system power for in-state small hydro was 5.9 TWh and 3.7 TWh, respectively.[29] From year-to-year, small hydro generation can fluctuate as much as 50 percent. Staff

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27 *2008 Net System Power Report*. July 2009. CEC-200-2009-010-CMF. See http://www.energy.ca.gov/2009publications/CEC-200-2009-010/CEC-200-2009-010-CMF.PDF.

28 See http://energyalmanac.ca.gov/electricity/.

29 *2006 Net System Power Report.* April 2007. CEC-300-2007-007. See http://www.energy.ca.gov/2007publications/CEC-300-2007-007/CEC-300-2007-007.PDF. The 2007 numbers were revised in the *2008 Net System Power Report*, *2008 Net System Power Report.* July 2009. CEC-200-2009-010-CMF. See http://www.energy.ca.gov/2009publications/CEC-200-2009-010/CEC-200-2009-010-CMF.PDF.

recommends using average annual generation for the past five years in California to estimate what the existing small hydro capacity might generate for the renewable net short calculation. The out-of-state small hydro generation totals have outliers in years 2005 and 2006, so an average of the past three years is proposed for the analysis. Since most of the hydro potential has been used, staff does not anticipate large amounts of new hydro capacity outside of efficiency upgrades at existing projects.

There is a similar phenomenon with wind generation. However, the generation performance tends not to be as drastic as the variations in hydro. According to the 2009 *Wind Technologies Market Report*, California's installed wind capacity increased by about 280 MW in 2009.[30] However, wind generation totals actually declined by about 0.8 TWh from 2008 to 2009.[31] A combination of varying wind resource per year and the forced curtailment of some wind projects may explain the differences.

> "In part as a result of El Niño, the year 2009, for example, was considered to be a generally poor wind year throughout much of the United States, with average wind speeds below their long-term average over much of the country. The year 2008, meanwhile, was generally considered to be a good wind year.
>
> Increasing amounts of wind power curtailment in recent years also significantly reduced sample-wide average capacity factors in 2009. Curtailment of project output due primarily to transmission inadequacy (and, as a consequence, low wholesale electricity prices) is a growing problem, primarily in Texas, but also in other markets.[32]"

In Texas, it was estimated that more than 15 percent of wind generation is typically curtailed because of these reasons. While there is no data for California on wind curtailment, it is assumed transmission constraints are an important issue that must be addressed.

Recently, there has been an increase in renewable generation imports. However, many of these imports are associated with short-term power purchase contracts (five years or fewer) with out-of-state wind projects. The IOU contract database includes about 1,500 MW of these types of projects that are currently on-line. For the most part, the wind projects were already operational, and staff believes that the energy is used as a short-term solution to

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30 U.S. Department of Energy. *2009 Wind Technologies Market Report*. Wiser, Ryan. Mark Bollinger. Page 10.

31 Total System Power for in-state wind was 5.7 TWh in 2008 and 5.0 TWh in 2009. See http://energyalmanac.ca.gov/electricity/system_power/2008_total_system_power.html and http://energyalmanac.ca.gov/electricity/total_system_power.html.

32 U.S. Department of Energy, *2009 Wind Technologies Market Report*, Wiser, Ryan. Mark Bollinger. Page 50.

comply with the 20 percent RPS. These projects are not included in the IOUs' Long Term Procurement Proceeding since the generation will likely serve renewable mandates that are expected in other states. The generation associated with these short-term contracts will not be used for the renewable net short calculations.

For facilities that came on-line during the reporting year, the reported generation will not account for an entire year's generation. New facilities are phased in before reaching their full operating capability, so generation totals must consider operational dates. If the facility came on-line early in the year, then the reported generation may be fairly consistent to the average annual generation potential. If the project commences commercial operation later in the year, the reported generation will be adjusted to reflect the expected generation of the facility.

Finally, because there is a delay in reporting annual generation data, the information will always be out of date. For this report, the intention was to have the base year set at December 31, 2009, but the 2010 generation data will not be reported until midway through 2011. In addition, it may be valuable to estimate or compensate for those projects that came on-line late in 2009 and did not contribute much to the 2009 generation totals. Furthermore, it may be important to capture those facilities that came on-line in 2010 and those under construction that will be on-line in 2011 since they will reduce the overall amount of incremental renewable generation needed. To reduce speculation on whether projects under construction will actually come on-line within the forecast period, staff suggests using only those projects expected to come on-line in 2011 that have a utility contract.

Using Installed Renewable Capacity Data to Estimate Existing Renewable Generation

An alternative approach to using actual generation data would be to substitute capacity data from the QFER dataset for the reported generation, while continuing to use specified purchases for out-of-state imports.[33] The benefit of this approach is that year-to-year variation in weather conditions is not factored into the in-state estimate. However, this approach also excludes facility-specific factors that reduce generator output. Some examples include onsite energy use, the age of the facility, deferred maintenance of the generation equipment, availability of biomass feedstock, landfill gas yields that are depleted over time, and the location of wind and solar facilities. California's renewable energy goals are mandated in terms of energy (MWh, GWh, or TWh); as such, the capacities must be

33 Utility contracts with out-of-state facilities are generally for a fixed amount of energy and not necessarily for the entire output of the facility. In addition, multi-jurisdictional utilities, such as PacifiCorp and Nevada Power, have some flexibility in how they allocate their out-of-state renewable purchases to meet California's renewable procurement mandates. Therefore, using installed capacities to estimate imported generation would likely overstate actual expected deliveries.

converted to units of energy. This will require assumed capacity factors (percentage of hours during the year that the facility is generating at full capacity) for each technology type.

Within the QFER dataset, California energy producers 1 MW in size and larger are required to report information regarding the capacity of their facility. The reporting of fossil-fueled sources greater than 50 MW is relatively easy to verify since the Energy Commission is responsible for issuing permits for these facilities. Smaller facilities and those that do not rely on thermal sources of generation (such as wind and solar PV) are more difficult to track and identify.

Another issue when using capacity values is how to treat contracts for renewable generation from out-of-state facilities. These contracts are for facilities whose energy may be redirected toward meeting their own state's renewable energy goals at the conclusion of the contract with California utilities. As a result, there is a possibility of overstating the renewable generation a decade from now if all of the contract generation available today is applied to the calculation. While it is possible that some amount of renewable generation will come from out-of-state contracts in the policy target year, it is unclear what relationship, if any, there is to the present contract amount.

The results from using capacity data are also sensitive to choices made about how to treat facilities that are currently under construction or in some phase of development. There is a strong case to be made for including a large percentage of renewable generation facilities in California that are undergoing construction. It is less clear what phase of the permitting and approval process can or should be considered sufficient to count generation as existing. The permitting and approval process is lengthy, and it is not uncommon for a large percentage of projects that are currently "in the pipeline" to never reach construction. Conversely, it might be inappropriate to completely ignore facilities that utilities have already invested a large amount of time and resources in a development process that all facilities must eventually face.

Proposed Method to Estimate Existing Renewable Generation for the Net Short Calculation

Staff proposes using a combination of reported energy and capacity data to estimate the existing renewable generation for renewable net short calculations. The following approach is proposed for estimating the existing renewable generation:

- An annual generation value for all renewable projects on-line before the most current full year of QFER energy data availability (currently December 31, 2009):
  - In-state electricity generation from QFER energy data, except small hydroelectric, two non-RPS eligible municipal solid waste facilities, and facilities that came on-line in the most current full year (2009) and report QFER generation

    - Reported out-of-state electricity generation from the most recent full year (2009) of PSDP renewable purchase claims, except small hydroelectric, short-term (5 year) out-of-state wind contracts, and claims from facilities that came on-line in the current year with incomplete reporting (2010)
    - Average annual reported electricity generation from small hydro generation over multiple (up to five) representative years, excluding extreme outlier (drought or flood) years
        - Average of in-state small hydroelectric, using reported electricity generation data to QFER (from 2005 to 2009 currently)
        - Average of reported out-of-state small hydroelectric PSDP claims (from 2007 to 2009[34])
- For facilities that have come on-line and are generating since the end of the most current complete year of QFER data, use the IOU and POU contract databases to estimate expected annual generation:
    - Electricity generation information from the Investor-Owned Utilities Contract Database for new, restart, and repower facilities with commercial on-line date during the current calendar year. (The most current estimate will use data between January 1, 2009, and November 30, 2010.[35])
    - Electricity generation information from the Publicly Owned Utilities Contract Database for new facilities with commercial on-line date during the current calendar year. (The most current estimate will use data between January 1, 2009, and November 30, 2010.[36])
- For facilities that are under construction and expected to be on-line by the end of the next calendar year (for this estimate undertaken in 2010, this would mean facilities anticipated to be on-line by December 31, 2011) and have power purchase agreements, apply an average capacity factor by generation technology type

Table 5 provides a summary of the existing renewable generation estimate for each of the two general approaches outlined in this section along with the estimate of the staff proposed method. The first column uses a strict historical generation approach to estimate existing renewable generation. This column uses both claimed and unclaimed in-state renewable generation for 2009, along with claimed imports from the PSDP. This column also uses utility contract information to estimate generation from facilities that have started generating energy since the last full QFER data set was collected. These facilities have a

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34 Years 2005 and 2006 were extreme outliers. Prior to 2007, reporting to PSDP may not have been as strictly enforced, and therefore a lot of small hydro generation may not have been reported.

35 See http://www.energy.ca.gov/portfolio/contracts_database.html.

36 See http://www.energy.ca.gov/2008publications/CEC-300-2008-005/index.html.

contract on-line date (COD) between January 1, 2009, and November 30, 2010. This approach does not include generation that is expected to come on-line before the next calendar year.

Table 5: Three Estimates of Existing Renewables Calculation (TWh)

			Historical Generation Method	Staff-Proposed Method	Installed Capacity Method
Facilities On-Line Prior to the Most Current Full-Year QFER Data Set					
2009 QFER Excluding Small Hydro and 2 Non-RPS MSW Plants			24	24	31.6
2009 Power Source Disclosure Program Out-of-State Renewable Purchase Claims; Excluding Small Hydro			5.2	5.2	5.2
2009 Power Source Disclosure Program Out-of-State Short-Term Wind Contracts			-1.8	-1.8	-1.8
QFER In-State Small Hydro Claims (Average 2005 – 2009)	**2005**	5.3			
	2006	5.9			
	2007	3.7			
	2008	3.6			
	2009	4.0			
	AVERAGE	4.5	4.5	4.5	4.5
Power Source Disclosure Program Out-of-State Small Hydro Claims (Average 2007 – 2009)	**2007**	1.0			
	2008	1.2			
	2009	1.3			
	AVERAGE	1.2	1.2	1.2	1.2
Facilities That Started Generating Since the End of the Most Current Full-Year QFER Data Set					
Instate Renewables Contracted Annual Generation With COD January 1, 2009 Through November 30, 2010			1.2	1.2	1.2
Out of State Renewables Contracted Annual Generation With COD January 1, 2009 Through November 30, 2010			4.6	4.6	4.6
Facilities Expected to Begin Generation Before the End of the Next Calendar Year					
Under Construction Renewables COD 12/1/2010 to 12/31/2011 Estimated Annual Generation			0.0	4.6	4.6
Summary Values for Use in Renewable Net Short Calculations					
IN-STATE RENEWABLE			**29.7**	**34.3**	**41.9**
OUT-OF-STATE RENEWABLE			**9.2**	**9.2**	**9.2**
TOTAL EXISTING RENEWABLE			**38.9**	**43.5**	**51.1**

Source: Energy Commission staff.

The second column represents the staff-proposed method outlined above. This column uses the same information as the historical generation approach and then adds facilities that are expected to be on-line before the end of calendar year 2011. The third column uses the installed capacity method to estimate expected generation from existing renewables. The key and only difference from the staff-proposed method is in the first row where installed renewable capacity is multiplied by technology specific capacity factors to estimate the amount of generation available from these sources in 2020.

Table 6 includes a list of the technology specific capacity factors that were used to estimate the generation from existing facilities and those that are under construction. These capacity factors were taken from the E3 calculator created for the CPUC to derive different renewable development portfolios.

Table 6: Fuel and Technology Specific Capacity Factors

FUEL/TECHNOLOGY TYPE	CAPACITY FACTOR (PERCENT)
BIOGAS	80
BIOMASS	85
GEOTHERMAL	83
SOLAR THERMAL	27
WIND	32
LARGE SCALE PV	24-27

Source: E3 33% calculator. December 3, 2010.

The existing renewable estimate that staff will use for the mid-range renewable net short calculation is 43.5 TWh, based on the most current information available and staff's proposed method. Staff is seeking stakeholder comments on whether alternative metrics for the existing renewable generation should be used for the renewable net short estimates.

Preliminary Renewable Net Short Ranges

Table 7 presents the previously described ranges of input variables and a proposed sequence of calculations for estimating the renewable net short. **Table 7** includes an upper and lower bound estimate of the calculated renewable net short, along with an illustrative estimate derived from using the staff-recommended approach and mid-range set of values.

The illustrative renewable net short estimate is based on a selected set of variables described in the preceding sections. The electricity retail sales value is the *2009 IEPR* base case forecast. The amount of additional energy efficiency measures is based on the mid-case incremental forecast, chosen as a moderate planning assumption. The staff expects that *AB 32 Scoping Plan* PV goals will be implemented and result in some reduction of electricity retail sales, so the estimated generation from the incremental PV additions should be included in the renewable net short calculation. A modest amount of load-reducing CHP is applied, recognizing that there is a potential for significant savings if the full potential of the program is achieved. These values represent a conservative set of planning assumptions, but it is important to consider the implications of uncertainties that can dramatically affect the renewable net short results.

The high and low estimates include the most extreme combination of values identified for each variable outlined in the report. This means that to estimate the maximum plausible renewable net short, staff combined the highest demand forecast with the lowest values of demand reduction measures and existing renewable generation. For the lowest renewable

net short value, staff combined the lowest demand forecast with the highest values of demand reduction and existing renewable generation.

Table 7: Calculation of Preliminary Ranges of Renewable Net Short

	All Values in TWh for the Year 2020	Formula	Lowest Renewable Net Short Estimate	Illustrative Example Renewable Net Short Estimate	Highest Renewable Net Short Estimate
1	Statewide Total Deliveries (Retail Sales)		297.5	303.3	310.3
2	Non RPS Deliveries (CDWR, WAPA, MWD)		13.6	13.6	13.6
3	Small LSE Sales (<200 GWh)		2.3	2.3	2.3
4	Retail Sales for RPS	4=1-2-3	281.6	287.4	294.4
5	Additional Energy Efficiency		19.9	17.1	15.2
6	Additional Rooftop PV		1.9	1.9	0.0
7	Additional Combined Heat and Power		19.8	7.2	0.0
8	Adjusted Statewide Retail Sales for RPS	8=4-5-6-7	240.0	261.2	279.2
9	**Total Renewable Energy Needed For 33% RPS**	**9=8* 33%**	**79.2**	**86.2**	**92.1**
	Existing and Expected Renewable Generation				
10	Total Instate Renewable Generation		41.9	34.3	29.7
11	Total Out-of-State Renewable Generation		9.2	9.2	9.2
12	**Total Existing Renewable Generation for CA RPS**	**12=10+11**	**51.1**	**43.5**	**38.9**
13	**Total RE Net Short to meet 33% RPS In 2020 (GWh)**	**13=9-12**	**28.1**	**42.7**	**53.2**

Source: Energy Commission staff.

The total renewable generation needed to meet a 33 percent policy goal in 2020 ranges between 79.2 TWh to 92.2 TWh (from line 9 of Table 7), which is a 13 TWh (16 percent) difference. This is the equivalent of the generation from about 5,300 MW solar-thermal power plants. Approximately half of this renewable goal difference is due to the CHP range of input assumptions. The retail sales range contributes 33 percent (4.2 TWh) of the calculated renewable difference, with the energy efficiency and PV range causing a 17 percent (8.7 TWh) difference. This range highlights how the characterization of key input variables and their associated uncertainties will affect the amount of estimated renewable energy that is needed to meet policy goals.

The renewable net short estimates have an even larger range of results. The calculated estimates for the renewable net short to meet a 33 percent policy goal in 2020 ranges from 28.1 TWh to 53.2 TWh (from line 13 of Table 7). This represents a 25.1 TWh (90 percent) difference in the estimates. The renewable net short range represents the equivalent generation from 10,300 MW of new solar-thermal plants or 8,200 MW of new wind facilities, a substantial range when considering the amount of back-up conventional generation or transmission infrastructure needed to support the renewable energy policy goals. Approximately half of the renewable net short range (12.2 TWh) is due to the differences in how existing generation is quantified, suggesting a careful consideration of this variable for the calculations. The balance of the difference is due to uncertainties associated with the electricity retail sales projection (4.2 TWh or 17 percent) and potential load reduction trajectories (8.7 TWh or 34 percent).

Given the resulting range of the calculated renewable net short, it is very important to understand the underlying set of input variables and corresponding array of associated uncertainties. Efforts to resolve the described uncertainties and improve the confidence in selected assumptions will minimize the risks for stranded infrastructure investments, lead to a more realistic measure of resource needs for system reliability and procurement decisions, and ensure that environmental goals are achieved.

Conclusion, Recommendations, and Next Steps

Energy Commission staff presents a recommended equation and recommended set of data sources and assumptions to use for estimating the renewable net short. The report also includes a discussion of the key variables that should be considered in the calculation. There are also important uncertainties regarding how the values of these variables can be estimated in future policy target years. It is important to remember that all values, regardless of the source, are estimates for up to 10 years into the future.

The electricity retail sales forecast that is used for the renewable net short calculation includes only existing and committed load reduction programs, such as funded energy efficiency programs. There are other demand reduction policy goals at some level that will likely occur. These additional programs must be considered as an adjustment to the electricity retail sales estimate for the renewable net short calculation. The programs to consider include uncommitted energy efficiency programs, self-generation additions, incremental distributed generation goals, and the combined heat and power policy goals.

A number of current electricity infrastructure studies do not consider the potential implications of these load reduction programs. Consequently, these studies likely overstate the amounts of renewable energy needed to satisfy the policy goal. Thereby, the recommended equation for calculating the renewable net short is as follows:

> ***Renewable Net Short (TWh) = ((Projected Retail Electricity Sales – Energy Efficiency Programs – Combined Heat & Power Customer Services – Distributed Generation Additions – Other Demand Reduction Programs) x Policy Goal Percent) – Generation from Existing Eligible Renewable Facilities***

The preliminary set of assumptions that staff provides for the renewable net short calculation is based on the most current electricity system assessments and projections. There are numerous studies and proceedings underway that will ultimately update some of the key input assumptions, such as the new electricity demand forecast for the *2011 IEPR* and regulatory incentives for CHP development. Given that the discussed uncertainties lead to a wide range in the input variables and even wider effect on the results of the renewable net short calculation, it is apparent that a narrow set of values or application of single-point

forecasts are not sufficient for addressing the infrastructure requirements for integrating renewable generation polity goals.

Allowing for a wide range of possible future scenarios may result in an array of outcomes when calculating retail electricity sales and the renewable net short goal. As it stands, the range of renewable net short estimates presented in this paper are lower than the values used in the different electricity system infrastructure studies. The new estimates will affect the determination of how many new transmission lines are needed to deliver new renewable generation electricity, the options for providing backup system services when integrating intermittent renewables, or the measured environmental benefits intended to reduce criteria and GHG emissions.

Developing a standard method and coordinated set of conventions for selecting assumptions will improve the ability to understand the context for different studies and to transfer findings from one research area to another. This will also promote consistency and improve an analytical link between the different infrastructure studies, leading to better informed policy development.

Energy Commission staff seek comments on the proposed renewable net short calculations and referenced assumptions. All feedback will be evaluated and discussed in a final staff paper for consideration in the *2011 IEPR*.