APPENDIX B

Supporting Documentation for the Technology Assessment

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Appendix B
Supporting Documentation for the Technology Assessment

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Appendix B1

Differences between the RPS and RES Calculators

This appendix describes differences in the parameters used to describe the operational characteristics of the 2009 RPS Calculator as described in the “Inputs and Assumptions to 33 Percent Renewables Portfolio Standard Implementation Analysis” [1] and the RES Calculator used by the ARB to facilitate implementation of the proposed RES regulation.

A. Modifications to the RPS Calculator

The following describes modifications made by Energy, Environmental, and Economics, Inc. (E3) to the 2009 RPS Calculator used by CPUC for its 33 percent Implementation Analysis to develop the RES Calculator. These modifications represent the current functionality of the RES Calculator developed. Both calculators were designed by E3 to estimate a cost and resource mix needed to meet a 33 percent renewable supply in 2020, and both use the same modeling logic and operating parameters. The primary differences between the calculators are that the 33 percent RES Calculator has been modified to include:

- The 2009 Integrated Energy Program Report (IEPR) load forecast;
- A new criteria pollutant module;
- Updated emissions calculation methodology;
- Updated costs and resource characterizations;
- Updated IOU contract information based on latest publicly-available data;
- Incorporation of POU resources into the 20 Percent RPS Scenario; and
- A new out-of-state REC module.

In addition to these modifications, several other minor modifications have been performed.

1. Updated 2009 IEPR Load Demand Forecast

The 2009 Integrated Energy Policy Report (IEPR)[2] evaluates and forecasts the supply and demand trends for electricity, natural gas, and transportation fuels in California. The current forecast is markedly lower than the forecast in the 2007 IEPR[3] primarily because of lower expected economic growth in both the near and long-term outlook, as well as increased expectations of savings from energy efficiency. In 2008, in-state generating facilities accounted for about 68 percent of total generation, with the remaining electricity coming from out-of-state imports. The 2009 IEPR forecasts that electricity consumption is projected to grow at a rate of 1.2 percent per year from 2010 through 2018, with peak demand growing at an average annual rate of 1.3 percent over the same period. The RES Calculator was updated to include the 2009 IEPR forecast, which predicts a significantly lower amount of electricity demand expected in 2020 compared to the 2007 IEPR forecast used in the RPS Calculator. Table B1-1 illustrates the different forecasts for years 2010-2020.

Table B1-1
Comparison of RPS and RES Retail Sales Forecasts

Year	RPS Calculator (2007 IEPR Forecast) (GWh)	RES Calculator (2009 IEPR Forecast) (GWh)
2010	285,182	267,932
2011	289,158	270,971
2012	293,039	274,616
2013	296,692	278,850
2014	300,231	281,957
2015	303,736	285,089
2016	307,148	288,255
2017	310,408	291,571
2018	313,671	294,768
2019*	317,072	298,010
2020*	320,519	301,385

** Extrapolated by E3*

2. New Criteria Pollutant Module

In addition to calculating CO_2 emissions, the RES Calculator was outfitted with a new module to calculate criteria pollutant emissions for each of the seven renewable resource types. This is accomplished with the use of emission factors multiplied by the GWh of operation. The results were used to determine the total and incremental emission impacts between the RPS and proposed RES regulation. The emission factors were provided by ARB to E3 for inclusion into the RES Calculator and include factors for ROG, NO_x, SO_x, CO, and $PM_{2.5}$. A listing of the individual emission factors and their source of origination can be found in Appendix D (Supporting Documentation for the Environmental Analysis). As a result of the addition of the criteria pollutant module, a new calculation methodology was added. In the process of developing the new module, E3 also updated parameters related to the cost, capacity factor, and supply of natural gas, and excluded some biomass and biogas resources based on current California local air district information.

3. CO_2 and Criteria Pollutant Emissions Calculation Methodology

To accommodate the new criteria pollutant module, E3 incorporated a new “physical model” into the RES Calculator that accompanies the original ratepayer model used to calculate the effect of CO_2 compliance on electricity ratepayers. The prior model was designed to estimate the impact of new infrastructure investment on electric ratepayers and included an accounting of CO_2 emissions, but from the perspective of electric ratepayers and not the entire electric sector. For example, the model assigned to

California ratepayers the fixed and variable costs, including CO_2 costs, of all resources either owned or contracted on a long-term basis to California utilities. The model assumes that remaining load is served via short-term or intermediate term “unspecified” market purchases. These are largely served with gas-fired resources, but the model did not specify which resources were selling to California loads in a given hour.

A full accounting of emissions requires this “unspecified” generation to be specified by type of resource (CCGT vs. CT), vintage (new vs. existing) and geography (in-state vs. out-of-state). E3 developed a physical model to estimate production by unspecified resources in each of these six categories. The new physical model calculates California and WECC-wide criteria pollutant emission impacts by applying emission factors to both the specified resources (resources that are based on PLEXOS Solutions modeling runs[a]) and the unspecified resources as estimated by E3. Table B1-2 identifies the differences between the two internal models that operate within the RES Calculator and describes which functions each model performs.

Table B1-2
Comparison of the RES Calculator’s Internal Emission Calculation Models

Ratepayer Model	Physical Model
Calculates effect of CO2 compliance on ratepayers	Does not consider electric ratepayers
Does not calculate criteria pollutant emissions	Calculates all criteria pollutant emissions in California and within the WECC
Does not calculate all regulated electric sector CO2 emissions	Calculates all regulated electric sector CO2 emissions
“Unspecified Generation” priced at market price, including CO2	Unspecified generation allocated to one of six categories based on type of resource (CCGT vs. CT), vintage (new vs. existing) and geography (in-state vs. out-of-state).

4. Updated Costs and Resource Characterizations

Since release of the 2009 RPS Calculator, developments have occurred with regard to energy prices and how certain renewable resources have developed within California and throughout the WECC. As a result, E3 updated the costs, prices, and resource characterizations related to solar, wind, natural gas prices, and Biomass/Biogas renewable resources as discussed in the following sections.

[a] Energy forecasts based on PLEXOS' advanced unit commitment and dispatch algorithm and hourly simulation time steps for current quarter, plus next three quarters. http://www.plexossolutions.com/.

Solar Photovoltaic

E3 revised the cost and capacity factor assumptions for solar photovoltaic (solar PV) technologies based on a review of cost estimates that E3 performed as part of a collaborative effort with the Transmission Expansion Planning Policy Committee (TEPPC). This review provides current resource cost assumptions for this generation technology. As a result, the levelized cost of generic solar PV resources dropped from $306/MWh to $187/MWh. The updated cost estimates are summarized in Table B1-3.

Table B1-3
Comparison of Solar PV Cost Estimates

	RPS Calculator	**RES Calculator**
Capital Cost ($/kW)	$7,065	$4,000
Fixed O&M ($/kW-yr.)	$44	$50
Capacity Factor	24%	25%
Levelized $/MWh Cost	$306	$187

On-Peak Wind Capacity Factors

E3 reviewed and updated the on-peak availability factors for wind resources. On-peak availability wind factors were reduced from a previous range of 20 to 30 percent down to 11 percent for in-state resources and 20 percent for out-of-state resources based on the California ISO's new methodology for calculating Net Qualifying Capacity (NQC). This change results in a lower capacity value for wind, which results in a slight increase in the wind resource ranking cost.

Natural Gas Price

The RES Calculator was updated to reflect a more recent forecast for the forecasted natural gas price in 2020 as described in the NYMEX Henry Hub[4] future price index for April 23, 2010. A comparison of price values for the two calculators is shown in Table B1-4. The update affects the cost of renewable resource generation for both gas-fired technologies (CCGT and SCGT) and the cost of unspecified market purchases to balance the resulting energy load.

Table B1-4
Update of Natural Gas Price Forecast
(all costs in nominal $/MMBtu)

	RPS Calculator	RES Calculator
2020 Henry Hub NYMEX Futures	$8.46	$7.97
Adder for Delivery to CA Generator	$0.37	$0.37
2020 Burner Tip Gas Price	$8.83	$8.34

Restricted Supply of Biomass and Biogas in California

The ARB and E3 performed an analysis of new biomass and biogas resources within California because the technologies emit more emissions than other renewable resources, such as new combined cycle gas turbines or zero emission technologies such as solar or wind. The analysis combined the results of the cost required to purchase NO_X offsets needed to permit and construct new facilities along with current contracting activity as reported by CPUC. The analysis showed that the 2007/08 cost of purchasing NO_X offsets for a new biomass or biogas facility ranged from between $12,000 per ton in the Bay Area up to $490,000 per ton in the South Coast region, making this an expensive operation to permit and construct. As a result, E3 modified the RES Calculator to restrict the supply of biomass resources in the South Coast Air Quality Management District and to incorporate the cost of NO_X offsets for biogas resources.

5. Updated IOU Contract Information Based on Latest CPUC Publicly-Available Data

As part of the RPS program, the CPUC provides updates on the status of renewable RPS projects and classifies projects as operational, approved, or pending, and includes other categories such as delayed, withdrawn, or terminated. For the purpose of this analysis, contracts that have not been classified by the CPUC as operational, approved, or pending have been categorized as “other” and are not included within the RES Calculator for use in the scenarios. E3 updated the RES Calculator with the most recent publicly-available version of the CPUC Contract Classifications as of May 5, 2010. This provides the RES Calculator with the most current list of renewable resources scheduled to be on-line and operational by 2020, which is required to make accurate forecasting projections.

6. Incorporation of POU Resources into the 20 Percent RPS Scenario

In addition to the incorporation of IOU contract data into the RES Calculator as described above, E3 also incorporated renewable energy obtained from POU procurement plans that the POUs provide to the CEC on a regular basis. The incorporation of this energy accounts for additional renewable energy (both currently operational and planned for construction by 2020) added to the renewable energy supply. ARB assumes that the POUs are procuring these resources to meet renewable targets mandated by the POUs' local governing bodies, rather than in anticipation of the ARB's 33 percent RES rulemaking. Hence, these resources are incorporated into the Business-as-Usual (20 percent RPS) Scenario. Resources with contracts that expire prior to 2020 are excluded from the RES Calculator. POU procurement data was obtained for the years 2010 and 2018 for inclusion in the RES Calculator. The data set was adjusted to match the calculator's end points of 2008 and 2020. Table B1-5 summarizes POU procurement by resource type assumed for years 2008 and 2020 and identifies whether the energy is obtained from an in-state or out-of-state location.

Table B1-5
POU Resources Incorporated into the RES Calculator
For Years 2010 and 2018

	In-State Generation (GWh)		Out-of-State Generation (GWh)	
Type	**2008**	**2020**	**2008**	**2020**
Geothermal	1,040	4,924	88	387
Biogas	560	1,573	638	638
Hydro	298	298	0	478
Biomass	172	172	170	182
Wind	2,029	3,484	3,742	3,742
Solar	37	873	0	0
Totals	4,135	11,323	2,767	5,427

7. New Out-of-State REC Module

In response to the ARB's proposal to include the unlimited use of RECs in the proposed RES regulation, E3 incorporated a new module into the RES Calculator that allows out-of-state REC transactions to be selected for inclusion in the 2020 33 percent RES portfolio, if doing so would reduce the cost of compliance. Therefore, the price of out-of-state RECs determines whether or not the RES Calculator selects RECs over other renewable resources. Out-of-State RECs are priced at the "net cost" or "green premium" (the resource's Levelized Cost of Energy (LCOE) minus the value of the "brown" attributes (energy and capacity) in the local out-of-state market). The RES Calculator assumes that all long-term REC transactions would be priced based on the full, incremental cost of developing new resources and delivering the energy to an out-of-state market. The quantity of renewable resources available to be developed for the purpose of generating a REC sale to California is assumed to be limited by physical realities such as the ability of each WECC sub-region to integrate wind energy into their own electricity system. The following sections describe how the supply and pricing of out-of-state RECs was determined for use in the RES Calculator.

a. Physical Limits on the WECC-Wide REC supply

E3 conducted new research in order to estimate a potential supply of RECs available to California by evaluating the ability of out-of-state regions to easily integrate wind resources into their own electricity systems. As a result, a new supply of wind resources, available to California in the form of RECs, has been integrated into the RES Calculator. Out-of-State REC transactions are drawn from a pool of out-of-state wind resources that are assumed will occur only if the local resource can be easily and inexpensively connected to the local transmission system without major upgrades. E3 selected an "average" wind resource in each zone for inclusion in the REC supply, rather than the best wind resources that are more likely to require new transmission to integrate. In addition, the supply of RECs in each region was also limited by the region's ability to easily integrate wind resources into their existing transmission system. Wind resources require flexible resources such as hydro or natural gas-fired turbines to back up the variable and unpredictable nature of the wind output. Hence, one limit on the ability to integrate wind in a given region is the quantity of load served by flexible generation. E3 estimated this as follows:

Ability to easily integrate wind = Load served by flexible generation
= Total load during a given hour
– Nuclear production
– Coal production
– Base (minimum run) hydro production
+ Export transmission capability

E3 estimated the total load served by flexible generation during each hour of the year for each of the 12 regions represented in the RES Calculator (baseload production data were provided by the WECC and were based on a 2020 production simulation run), added the total capability to export energy over the existing transmission system, and assumed that the minimum value represents a reasonable limit on the region's ability to easily integrate wind. Additional wind could likely be interconnected, but would require either major new transmission upgrades or substantial changes to the operations of the regional power grid. In either case, the economics of a potential REC transaction would be strongly affected.

While this method establishes the outer limit of each region's ability to interconnect wind power, most other regions have their own RPS requirements and have plans to install thousands of MW of wind. Hence, E3 assumed that only half of the region's ability to interconnect wind is available to California. The resulting limits on RECs in each jurisdiction are listed in Table B1-6.

Table B1-6
Estimated Amount of Wind RECs Available to California

Wind Energy From WECC	Amount of Energy Estimated for local RPS requirements	Wind RECs available for California
18,138 MW	9,084 MW	9,084

b. Policy Limits on California REC Procurement

In addition to physical limits on the supply of RECs, the user can also select a policy limit on the quantity of RECs allowed under California procurement rules. The limit can range from 0 percent to 100 percent of the incremental renewable resources to be procured. E3 selected 100 percent to model the ARB's Proposed Regulation, and zero percent to model an in-state only alternative scenario as discuss in Chapter XI of this report (Alternatives Analysis).

c. Pricing of Out-of-State RECs

Pricing of Out-of-State REC transactions is conducted in a similar fashion as the ranking of in-state renewable resources. Resources are ranked based on their "net cost"– the resource's Levelized Cost of Energy (LCOE) minus the value of the "brown" attributes (energy and capacity) in the local market. In-state transactions are modeled as "bundled" transactions, i.e., transactions that include both the energy and REC attributes. Out-of-State transactions can be either bundled or unbundled. In either case, energy is delivered from the resource into the local market. In the bundled case, the California load serving entity (LSE) remarkets the energy and uses the revenue to reduce rates. In the "unbundled" case, the renewable developer remarkets the energy, and this additional revenue reduces the REC price paid by California ratepayers. The economic value of the transaction is the same whether the energy and the REC are bundled and sold to the California LSE, or whether the California LSE buys only the REC. Table B1-7 shows an example of the pricing and value of out-of-state wind RECs to California ratepayers of both bundled and unbundled REC transactions.

Table B1-7
Pricing Estimates of In-State and Out-of-State Wind RECs

	In-State Wind Resource	Out-of-State Wind Resource
Levelized Cost of Wind Energy	$90	$75
Integration Costs in Local Market	$6	$6
Energy Value in Local Market	($55)	($45)
Capacity Value in Local Market	($5)	--
Net Cost to CA Ratepayers	$36	$36
REC Price	--	$36

REFERENCES

[1] California Public Utilities Commission, 2009. CPUC 33% RPS Implementation Analysis Calculator, http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm

[2] California Energy Commission, 2009. 2009 Integrated Energy Policy Report, http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF (CD: CEC-100-2009-003-CMF)

[3] California Energy Commission, 2007. 2007 Integrated Energy Policy Report, http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CMF.PDF (CEC-100-2007-008-CMF)

[4] Oilnergy. Nymex Henry-Hub Natural Gas Price, http://www.oilnergy.com/1gnymex.htm

Appendix B2

INPUTS AND ASSUMPTIONS TO 33% RENEWABLES PORTFOLIO STANDARD IMPLEMENTATION ANALYSIS

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UPDATES TO THE JULY 2009 VERSION

Page 20, Paragraph 1: "$52/Megawatt-Hour (MWh)" corrected to "$52/Kilowatt-Year"

Page 26, Table 6: The previous version of this table was truncated in the July 2009 version. This version contains the whole table.

Page 33, Paragraph 1: "92% capacity factor" corrected to "65% capacity factor".

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1. Renewable Resource Supply Data

The following table provides a description of the various resources that E3 draws from to model renewable resource potential within California and around the Western Electricity Coordinating Council (WECC).

Table 1. Description of Data Sources

Data Source	Description
CPUC Energy Division Project Database (ED Database)	The Energy Division maintains a database of renewable energy projects representing approximately 56 Terawatt- Hours (TWh) of electricity that the Investor-Owned Utilities (IOUs) have selected.[1] The projects are in various stages of completion, ranging from projects under negotiation (i.e., short-listed for negotiating a contract by an IOU), to projects that are online. Incorporating short-listed projects distinguishes this study from prior analysis by enabling it to take advantage of information about commercial interest in specific new renewable projects.
Renewable Energy Transmission Initiative (RETI)	The RETI process developed a detailed and comprehensive database of renewable resource potential in California and neighboring states.[2] The RETI analysis provides a stakeholder-vetted engineering assessment of renewable resources at the project level by location and technology type. The RETI dataset relies on proxy projects that are based on expressed commercial interest, it does not include short-listed projects. In addition to renewable resource information, the RETI database categorizes clusters of renewable development into renewable resource zones, which are extremely valuable in the estimates of resource development and transmission need.
GHG Calculator	E3 developed a database of renewable resource potential throughout the WECC as part of its GHG modeling analysis for the California Public Utilities Commission (CPUC), the California Air Resources Board (ARB), and the Energy Commission. The study team relied on the E3 database for information on renewable resources outside of California.[3]
Estimates of distributed renewable energy potential	E3 developed new estimates of the technical potential to connect distributed renewable generation in California. While the distributed solar photovoltaic potential estimates that were developed for this study are very high-level, they are useful for the purpose of testing the benefits and costs of distributed renewables relative to central station power plants to achieve a 33% RPS.

E3 takes the resource data for most California renewables from the RETI process, which performed a site-specific audit of renewable energy resources

[1] The CPUC maintains a public version of this database at http://www.cpuc.ca.gov/renewables.
[2] More information on the Renewable Energy Transmission Initiative process can be found here: http://www.energy.ca.gov/reti/documents/index.html.
[3] E3 compiled this database from GIS data from the National Renewable Energy Laboratory, the Energy Information Administration , the Energy Commission, and the Western Governor's Association. More detailed information is available here: http://www.ethree.com/CPUC_GHG_Model.html.

within the state. This analysis provides measures of resource availability, cost, and performance at sites throughout California. E3 supplements the RETI resource assessments with project data from the CPUC Energy Division Project Database, which tracks the results of the IOU renewable solicitations.

For those out-of-state areas that were not looked at in detail during the RETI process, E3 takes resource assessments from the work done in preparing the GHG Calculator. Brief descriptions of E3's method for determining resource potential for each of the different resource types are shown below.

Wind: Wind resource availability is based on data from the National Renewable Energy Laboratory (NREL), which used Geographic Information Systems (GIS) data to estimate the total wind resource availability in the WECC. However, in the 33% RPS Implementation Analysis, E3 updates the method for calculating feasible potential from the total potential identified by NREL. Previously, NREL had filtered according to the ability of the local transmission system to accept more capacity, giving preference to the highest quality wind resources. This resulted in the development of exclusively high quality wind, which E3 found implausible. For the 33% RPS Implementation Analysis, E3 instead applies blanket exclusions to the NREL total wind potential estimates for each class in an attempt to better reflect the actual mix of wind resources that will be available for development in the future. The table below shows the difference between the total NREL resource potential and the amounts resulting from the application of the two different filters (NREL Transmission Filtered Resource Potential and E3 Blanket Exclusion Resource Potential) for Wyoming. Due to the lack of available information on Alberta wind potential, E3 assumes that Alberta has a wind portfolio identical to the closest zone for which data was available, Montana.

Table 2. Wyoming Wind Potential Under Different Filters (Megawatts [MW])

	NREL Total Resource Potential	NREL Transmission-Filtered Resource Potential (% of Total)	E3 Blanket Exclusion Resource Potential (% of Total)
Class 3	361,186	0 (0%)	108,356 (30%)
Class 4	200,335	0 (0%)	60,100 (30%)
Class 5	78,585	77,918 (99%)	23,576 (30%)
Class 6	43,967	43,967 (100%)	8,793 (20%)
Class 7	16,853	16,835 (100%)	1,685 (10%)

Biomass/Biogas: Biomass and biogas estimates in the US portion of the WECC are taken from a 2005 NREL report detailing the nationwide resource potential for biomass.[4] This report provides information on the total theoretical potential available in the western US. E3 uses the ratio of theoretical potential to likely development calculated in the GHG model to adjust this total western US potential downward to a feasible potential estimate. Biomass resources in British

[4] NREL, A Geographic Perspective on the Current Biomass Resource Availability in the United States, NREL/TP-560-39181, December 2005.

Columbia (BC) are taken from information contained in the RETI report, while the Biogas resource estimates are taken from the BC Hydro 2006 Integrated Electricity Plan.[5]

Geothermal: Geothermal resources in Nevada are estimated based on a 2004 study on geothermal resource potential in California and Nevada for the California Energy Commission,[6] which details site-specific resource potential for 43 sites in Nevada. The geothermal resource potential for the remainder of the western US is based on estimates from the Western Governor's Association Clean and Diversified Energy Advisory Committee 2006 Geothermal Task for Report,[7] while estimates for British Columbia are taken from the BC Hydro 2006 Integrated Electricity Plan.[8]

Solar Thermal: Total resource potential for solar thermal (referred to in the CPUC GHG documentation as Concentrating Solar Power) is taken from an NREL GIS dataset[9] that assigns a solar resource class between 1 and 5 to all land area in the WECC, screening out those areas such as federally protected lands and urban settings that would prevent development. E3 assumes that only class 4 and 5 resources will be developed.

Small Hydro: Hydro potential for the western US is taken from the site-specific information contained in Renewable Fuels Module of the EIA's 2007 Annual Energy Outlook.[10] E3 excludes all locations with environmental characteristics that would reduce the likelihood of development, and those locations that would require the construction of new dams. Small hydro potential in British Columbia is taken from a 2007 study for BC Hydro[11] looking at the run-of-river resources available for development. Due to the lack of data, E3 assumes a resource potential of 100 MW of small hydro in Alberta to be consistent with the value used in the GHG Model.

Distributed Renewables: E3 defines distributed renewables as those resources that can be interconnected to the California system without the need for system upgrades or additional backbone transmission lines. The distributed zones in Tables 3, 4, and 5 contain the distributed renewable projects. These projects do not fall into any RETI-identified or GHG Calculator identified resource zones because they are not geographically connected and do not need transmission.

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[5] BC Hydro, "2006 Integrated Electricity Plan (IEP)", March 2006. http://www.bchydro.com/info/iep/iep8970.html.
[6] GeothermEx, Inc., "New Geothermal Site Identification and Qualification", P500-04-051, prepared for CEC, April 2004.
[7] Western Governors' Association (WGA), Clean and Diversified Energy Initiative, "Geothermal Task Force Report," January 2006.
[8] BC Hydro, "2006 Integrated Electricity Plan (IEP)", March 2006. http://www.bchydro.com/info/iep/iep8970.html.
[9] For more information, see http://www.nrel.gov/csp/troughnet/solar_data.html.
[10] http://www.eia.doe.gov/oiaf/archive/aeo07/assumption/renewable.html.
[11] Kerr Wood Leidal, "Run-of-River Hydroelectric Resource Assessment.

They share similar characteristics that allowed them to be grouped together for computational simplicity.

The distributed wind and geothermal projects are sites from the RETI analysis. This dataset also includes two biomass projects that were qualified as distributed biomass. The remaining estimates for the potential amount of distributed biomass and biogas are based on discussions with stakeholders on the developable potential in California.

The distributed solar resources can be qualified as one of four types of solar photovoltaic (PV) installation: large roof urban PV (larger than 1/3 acre), small roof urban PV, rural ground mounted PV, or large remote ground mounted PV. E3 developed an estimate of the total potential for each type in the service areas of the three large IOUs. Large roof urban PV potential was developed with the help of Black and Veatch, based on GIS data identifying large roofs in urban areas with close proximity to distribution substations. E3 put an upper limit on large roof PV potential at 30% of the peak substation load,[12] and assumed that 67% of that potential would actually be developed. For substations with remaining capacity under the 30% cap after the large roof PV, E3 assumed that small roof PV would fill one-third of that remaining capacity.[13] In rural areas where there were no large roofs, E3 capped ground mounted PV installations at 10% of the substation capacity.[14] In remote areas, E3 assumed that ground mounted two-axis tracking PV installations could be developed above the 30% cap at the local substation level, but assigned a cost penalty of $52/Kilowatt-Year to reflect the transmission upgrades that would be associated with integrating this much capacity.

The following tables show the total resource availability, by zone and resource, for each of the 52 zones modeled in the analysis.

[12] Large Roof PV installations were capped at 30% to reflect compliance with Rule 21 under optimistic assumptions regarding the ability of substations to accept interconnections.
[13] For example, if the large roof PV installations in close proximity of a given substation amounted to 20% of the capacity of the substation assuming one third participation, small roof PV installations would be capped at 3.3% (33%/(30% - 20%)).
[14] Rural PV installations were capped at 10% of substation capacity to reflect compliance with Rule 21. The limits for rural substations were lower because E3 expects that a rural substation will vary more, so its ability to accept interconnections will be reduced.

Table 3. Resources by Type and Zone, MW

	Total Resources by Resource Type (MW)						
	Biogas	Biomass	Geothermal	Hydro - Small	Solar	Wind	*Total*
Alberta	-	-	-	100	-	268,452	*268,552*
Arizona-Southern Nevada	33	43	-	-	157,400	7,812	*165,289*
Baja	-	-	-	-	-	5,420	*5,420*
Barstow	-	-	-	-	1,375	1,115	*2,490*
British Columbia	50	1,520	244	12,344	-	6,630	*20,788*
Carrizo North	-	-	-	4	3,122	-	*3,126*
Carrizo South	-	-	-	-	3,262	-	*3,262*
Colorado	59	44	20	-	18,049	84,242	*102,415*
Cuyama	-	-	-	-	450	-	*450*
Distributed Biogas	249	-	-	-	-	-	*249*
Distributed Biomass	-	162	-	-	-	-	*162*
Distributed CPUC Database	30	226	120	22	127	-	*525*
Distributed Geothermal	-	-	175	-	-	-	*175*
Distributed Solar	-	-	-	-	6,077	-	*6,077*
Distributed Wind	-	-	-	-	-	468	*468*
Fairmont	-	138	-	-	5,707	1,455	*7,300*
Imperial East	-	-	-	-	2,160	123	*2,283*
Imperial North	-	45	1,559	-	1,970	195	*3,769*
Imperial South	-	43	64	-	4,385	46	*4,537*
Inyokern	-	-	-	-	2,601	287	*2,887*
Iron Mountain	-	-	-	-	5,968	62	*6,031*
Kramer	-	-	24	-	7,236	203	*7,463*
Lassen North	-	26	27	-	1,199	1,134	*2,386*
Lassen South	-	-	-	-	1,199	1,000	*2,199*
Montana	5	162	-	36	-	268,452	*268,655*
Mountain Pass	-	-	-	-	3,480	878	*4,359*
Needles	-	-	-	-	1,354	455	*1,808*
New Mexico	18	26	80	-	158,465	93,826	*252,415*
Northeast Nevada	-	-	-	-	-	418	*418*
Northwest	88	1,060	335	231	30,964	24,759	*57,438*
Not Assigned	1	1,210	45	-	2,424	470	*4,149*
Out-of-State Early	-	87	58	15	-	1,902	*2,062*
Out-of-State Late	-	-	-	-	534	1,400	*1,934*
Owens Valley	-	-	35	-	1,419	-	*1,454*
Palm Springs	-	-	-	-	-	806	*806*
Pisgah	-	-	-	-	4,999	1,390	*6,389*
Remote DG	-	-	-	-	9,000	-	*9,000*
Reno Area/Dixie Valley	-	-	1,182	-	7,449	863	*9,493*
Riverside East	-	-	-	-	10,732	-	*10,732*
Round Mountain	-	81	240	-	-	231	*552*
San Bernardino - Baker	-	-	-	-	1,200	-	*1,200*
San Bernardino - Lucerne	-	91	-	-	4,223	641	*4,955*
San Diego North Central	-	20	-	-	-	347	*367*
San Diego South	-	-	-	-	-	903	*903*
Santa Barbara	-	-	-	-	-	515	*515*
Solano	-	-	-	-	-	1,044	*1,044*
South Central Nevada	15	15	108	9	142,613	237	*142,997*
Tehachapi	-	37	-	-	6,179	5,464	*11,680*
Twentynine Palms	-	-	-	-	800	67	*867*
Utah-Southern Idaho	21	181	1,040	220	64,942	12,152	*78,557*
Victorville	-	-	-	-	1,760	436	*2,196*
Wyoming	2	22	-	17	-	202,310	*202,352*
Total	***572***	***5,238***	***5,355***	***12,999***	***674,824***	***998,611***	***1,697,600***

Table 4. Resources by Type and Zone, Gigawatt-hours (GWh)

	Total Resources by Resource Type (GWh)						
	Biogas	Biomass	Geothermal	Hydro - Small	Solar	Wind	*Total*
Alberta	-	-	-	438	-	712,868	*713,306*
Arizona-Southern Nevada	248	302	-	-	354,224	20,052	*374,826*
Baja	-	-	-	-	-	15,718	*15,718*
Barstow	-	-	-	-	3,314	3,015	*6,329*
British Columbia	372	10,653	1,868	49,186	-	18,439	*80,518*
Carrizo North	-	-	-	16	6,741	-	*6,757*
Carrizo South	-	-	-	-	7,054	-	*7,054*
Colorado	442	305	152	-	39,153	220,316	*260,368*
Cuyama	-	-	-	-	998	-	*998*
Distributed Biogas	1,855	-	-	-	-	-	*1,855*
Distributed Biomass	-	1,138	-	-	-	-	*1,138*
Distributed CPUC Database	223	1,582	913	95	305	-	*3,118*
Distributed Geothermal	-	-	1,344	-	-	-	*1,344*
Distributed Solar	-	-	-	-	11,200	-	*11,200*
Distributed Wind	-	-	-	-	-	1,289	*1,289*
Fairmont	-	967	-	-	14,865	4,369	*20,200*
Imperial East	-	-	-	-	5,230	338	*5,568*
Imperial North	-	315	12,064	-	4,659	565	*17,603*
Imperial South	-	299	448	-	10,315	120	*11,182*
Inyokern	-	-	-	-	6,800	716	*7,516*
Iron Mountain	-	-	-	-	14,131	151	*14,282*
Kramer	-	-	168	-	18,481	473	*19,122*
Lassen North	-	182	202	-	2,352	3,049	*5,785*
Lassen South	-	-	-	-	2,502	3,180	*5,682*
Montana	37	1,136	-	177	-	712,868	*714,218*
Mountain Pass	-	-	-	-	8,395	2,445	*10,840*
Needles	-	-	-	-	3,302	1,261	*4,562*
New Mexico	135	180	609	-	345,130	245,360	*591,414*
Northeast Nevada	-	-	-	-	-	1,264	*1,264*
Northwest	656	7,430	2,548	940	47,390	64,968	*123,932*
Not Assigned	4	8,480	355	-	4,211	1,410	*14,460*
Out-of-State Early	-	610	445	66	-	5,497	*6,617*
Out-of-State Late	-	-	-	-	1,304	3,991	*5,295*
Owens Valley	-	-	264	-	3,654	-	*3,918*
Palm Springs	-	-	-	-	-	2,711	*2,711*
Pisgah	-	-	-	-	12,130	3,655	*15,785*
Remote DG	-	-	-	-	19,236	-	*19,236*
Reno Area/Dixie Valley	-	-	8,996	-	16,925	2,593	*28,514*
Riverside East	-	-	-	-	25,689	-	*25,689*
Round Mountain	-	567	1,682	-	-	643	*2,893*
San Bernardino - Baker	-	-	-	-	2,847	-	*2,847*
San Bernardino - Lucerne	-	638	-	-	10,479	1,796	*12,914*
San Diego North Central	-	140	-	-	-	934	*1,074*
San Diego South	-	-	-	-	-	2,583	*2,583*
Santa Barbara	-	-	-	-	-	1,423	*1,423*
Solano	-	-	-	-	-	3,309	*3,309*
South Central Nevada	114	104	820	42	328,012	702	*329,794*
Tehachapi	-	259	-	-	15,753	16,198	*32,209*
Twentynine Palms	-	-	-	-	2,045	194	*2,239*
Utah-Southern Idaho	158	1,270	7,917	907	132,758	31,468	*174,478*
Victorville	-	-	-	-	4,635	1,227	*5,862*
Wyoming	16	154	-	93	-	557,296	*557,559*
Total	***4,260***	***36,711***	***40,795***	***51,960***	***1,486,219***	***2,670,453***	***4,290,398***

2. Zone Definitions

The zones that E3 examines in the 33% RPS Implementation Analysis come primarily from two sources: (1) RETI and (2) the GHG Calculator. The RETI process identifies Competitive Renewable Energy Zones (CREZs) within California and Mexico, representing bundles of renewable resources that can serve as potential origins for large transmission lines carrying renewable energy to load centers. In developing the GHG Calculator, E3 divides the Western Electricity Coordinating Council (WECC) into zones by geography and transmission system topology. These “GHG Calculator zones” form the basis for the classification of resources outside of California.

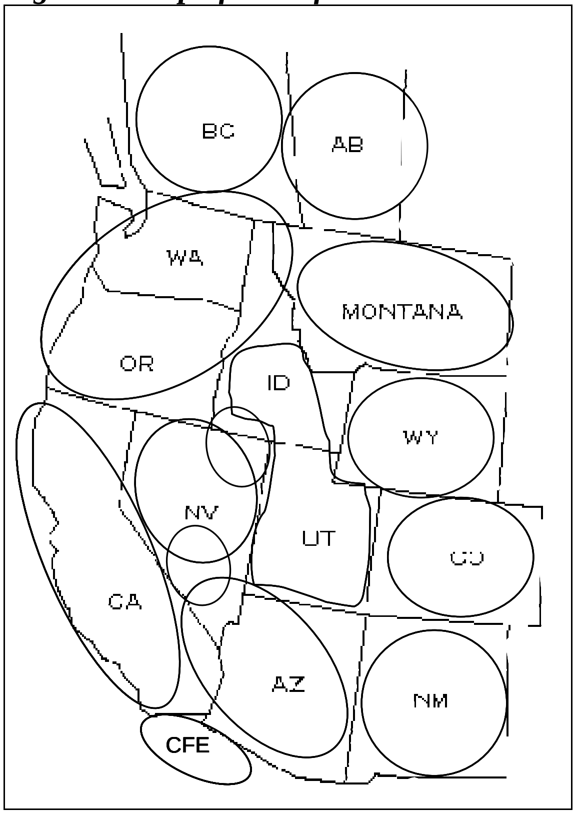
Table 5. Resource Zones

Resource Zone Name	Description or Source
Alberta	GHG Calculator Zone
Arizona – Southern Nevada	GHG Calculator Zone
Baja	RETI CREZ
Barstow	RETI CREZ
British Columbia	Combination of RETI CREZ / GHG Calculator Zone
Carrizo North	RETI CREZ
Carrizo South	RETI CREZ
Colorado	GHG Calculator Zone
Cuyama	RETI CREZ
Distributed Biogas	Biogas resources from RETI and E3 that are assumed to be able to come online without substantial new transmission
Distributed Biomass	Biomass resources from RETI and E3 that are assumed to be able to come online without substantial new transmission
Distributed CPUC Database	Resources of all types from the Energy Division (ED) Database that are assumed to be able to come online without substantial new transmission
Distributed Geothermal	Geothermal resources from RETI and E3 that are assumed to be able to come online without substantial new transmission
Distributed Solar	Solar resources from RETI and E3 that are assumed to be able to come online without substantial new transmission
Distributed Wind	Wind resources from RETI and E3 that are assumed to be able to come online without substantial new transmission
Fairmont	RETI CREZ
Imperial East	RETI CREZ
Imperial North	RETI CREZ
Imperial South	RETI CREZ
Inyokern	RETI CREZ
Iron Mountain	RETI CREZ
Kramer	RETI CREZ
Lassen North	RETI CREZ

Lassen South	RETI CREZ
Montana	GHG Calculator Zone
Mountain Pass	RETI CREZ
Needles	RETI CREZ
NE Nevada	GHG Calculator Zone
New Mexico	GHG Calculator Zone
Northwest	GHG Calculator Zone
Not Assigned	Resources listed in RETI Database that are a) not assigned to a specific geographic zone and b) assumed to require new transmission
Owens Valley	RETI CREZ
Out-of-State Early	Out-of-State resources from ED Database that are either under contract or short-listed and expected to come online in the near term
Out-of-State Late	Out-of-state resources from ED database that are either under contract or short-listed and expected to come online in the long term, plus 1,400 MW of additional out-of-state wind resources assumed to be available to California utilities
Palm Springs	RETI CREZ
Pisgah	RETI CREZ
Remote DG	RETI estimates of PV potential, modified for RPS Calculator
Reno Area / Dixie Valley	GHG Calculator Zone
Riverside East	RETI CREZ
Round Mountain	RETI CREZ
San Bernardino – Baker	RETI CREZ
San Bernardino – Lucerne	RETI CREZ
San Diego North Central	RETI CREZ
San Diego South	RETI CREZ
Santa Barbara	RETI CREZ
Solano	RETI CREZ
South Central Nevada	GHG Calculator Zone
Tehachapi	RETI CREZ
Twentynine Palms	RETI CREZ
Utah – Southern Idaho	GHG Calculator Zone
Victorville	RETI CREZ
Wyoming	GHG Calculator Zone

The following map shows the approximate division of the non-California zones.

Figure 1. Map of Out-of-State Zones[15]



3. Transmission Cost and Sizing Assumptions

The 33% RPS Implementation Analysis looks at the relative values of fixed capacity transmission lines from the various zones. The size of the transmission lines from each zone are determined by the total resource availability in that zone, up to a maximum of 3,000 MW. The lines are modeled to originate at the center of the resource clusters in each zone[16] and terminate at either the Tesla (near Tracy, CA) or Victorville substations, whichever one is closest. These two substations were chosen because they represent transmission hubs in close proximity to major California load centers.

With the exception of the line from British Columbia, which E3 models as a hybrid alternating current (AC) and direct current (DC) line, E3 assumes all lines to be AC lines. The cost of these lines is estimated using a generic line costing model that accounts for both equipment (substations, towers, conductors, etc.) and right-of-way acquisition.[17] The following table details the cost and size of the

[15] This map is a modified version of the one found in the GHG analysis, produced by E3.
[16] For example, the Wyoming line originates in eastern rather than central Wyoming due to the fact that most wind resources are located in the eastern part of the state.
[17] This transmission costing model was the same as that used for the GHG Calculator. It can be found at http://www.ethree.com/GHG/Transmission_Line_Cost_2007-11-16.xls.

transmission line that E3 assumes from each zone, as well as the losses associated with that line.

Table 6. Transmission Lines

CREZ Name	Assumed Line Capacity (MW)	Overbuild factor	Transmission Line Distance (miles)	Transmission Configuration	Total Cost ($MM 2008)	Incremental Losses	Levelized Cost, $/yr
Alberta	3,000	0%	1,498	500 kV Double Circuit AC Line	$ 7,998	17.2%	$ 997
Arizona-Southern Nevada	1,500	0%	403	500 kV Single Circuit AC Line	$ 2,044	4.6%	$ 255
Baja	1,500	0%	211	500 kV Single Circuit AC Line	$ 1,425	2.4%	$ 178
Barstow	1,800	20%	97	500 kV Single Circuit AC Line	$ 889	1.1%	$ 111
British Columbia	3,900	30%	1,166	500 kV Double Circuit AC Line and 3000 MW DC Line	$ 5,100	13.4%	$ 636
Carrizo North	1,500	0%	174	500 kV Single Circuit AC Line	$ 1,127	2.0%	$ 140
Carrizo South	1,500	0%	237	500 kV Single Circuit AC Line	$ 1,478	2.7%	$ 184
Colorado	3,000	0%	936	500 kV Double Circuit AC Line	$ 5,250	10.8%	$ 654
Cuyama	500	0%	249	230 kV Single Circuit AC Line	$ 1,094	0.5%	$ 136
Distributed Biogas	n/a	0%	n/a	n/a	$ -	0.0%	$ -
Distributed Biomass	n/a	0%	n/a	n/a	$ -	0.0%	$ -
Distributed CPUC Database	n/a	0%	n/a	n/a	$ -	0.0%	$ -
Distributed Geothermal	n/a	0%	n/a	n/a	$ -	0.0%	$ -
Distributed Solar	n/a	0%	n/a	n/a	$ -	0.0%	$ -
Distributed Wind	n/a	0%	n/a	n/a	$ -	0.0%	$ -
Fairmont	1,650	10%	13	500 kV Single Circuit AC Line	$ 549	0.2%	$ 68
Imperial East	1,500	0%	224	500 kV Single Circuit AC Line	$ 1,472	2.6%	$ 183
Imperial North	1,500	0%	151	500 kV Single Circuit AC Line	$ 1,085	1.7%	$ 135
Imperial South	1,500	0%	181	500 kV Single Circuit AC Line	$ 1,199	2.1%	$ 149
Inyokern	1,650	10%	118	500 kV Single Circuit AC Line	$ 948	1.4%	$ 118
Iron Mountain	1,500	0%	170	500 kV Single Circuit AC Line	$ 1,120	2.0%	$ 140
Kramer	1,650	10%	82	500 kV Single Circuit AC Line	$ 823	0.9%	$ 103
Lassen North	1,800	20%	266	500 kV Single Circuit AC Line	$ 1,642	3.1%	$ 205
Lassen South	1,800	20%	344	500 kV Single Circuit AC Line	$ 1,940	4.0%	$ 242
Montana	3,000	0%	1,105	500 kV Double Circuit AC Line	$ 6,090	12.7%	$ 759
Mountain Pass	1,650	10%	194	500 kV Single Circuit AC Line	$ 1,287	2.2%	$ 160
Needles	1,200	20%	395	230 kV Single Circuit AC Line	$ 1,167	1.0%	$ 145
New Mexico	3,000	0%	237	500 kV Double Circuit AC Line	$ 4,522	9.1%	$ 564
Northeast Nevada	500	0%	790	230 kV Double Circuit Line	$ 1,232	0.9%	$ 154
Northwest	1,500	0%	738	500 kV Single Circuit AC Line	$ 3,270	8.5%	$ 408
Not Assigned	n/a	0%	n/a	n/a	$ -	0.0%	$ -
Out-of-State Early	n/a	0%	n/a	n/a	$ -	3.0%	$ -
Out-of-State Late	n/a	0%	n/a	n/a	$ -	3.0%	$ -
Owens Valley	1,500	0%	188	500 kV Single Circuit AC Line	$ 1,211	2.2%	$ 151
Palm Springs	1,000	0%	73	500 kV Single Circuit AC Line	$ 668	0.3%	$ 83
Pisgah	1,800	20%	111	500 kV Single Circuit AC Line	$ 908	1.3%	$ 113
Remote DG	n/a	0%	n/a	n/a	$ -	1.0%	$ -
Reno Area/Dixie Valley	1,500	0%	485	500 kV Single Circuit AC Line	$ 2,332	5.5%	$ 291
Riverside East	3,000	0%	169	500 kV Double Circuit AC Line	$ 1,646	1.9%	$ 205
Round Mountain	500	0%	191	230 kV Single Circuit AC Line	$ 879	0.4%	$ 110
San Bernardino - Baker	1,500	0%	125	500 kV Single Circuit AC Line	$ 1,002	1.4%	$ 125
San Bernardino - Lucerne	1,800	20%	64	500 kV Single Circuit AC Line	$ 732	0.7%	$ 91
San Diego North Central	500	0%	45	230 kV Single Circuit AC Line	$ 585	0.1%	$ 73
San Diego South	1,000	0%	205	230 kV Double Circuit AC Line	$ 1,118	0.9%	$ 139
Santa Barbara	500	0%	280	230 kV Single Circuit AC Line	$ 1,153	0.6%	$ 144
Solano	1,000	0%	20	230 kV Double Circuit AC Line	$ 538	0.1%	$ 67
South Central Nevada	1,650	10%	215	500 kV Single Circuit AC Line	$ 1,345	2.5%	$ 168
Tehachapi	3,000	0%	80	500 kV Double Circuit AC Line	$ 1,252	0.9%	$ 156
Twentynine Palms	1,000	0%	112	230 kV Double Circuit AC Line	$ 766	0.5%	$ 95
Utah-Southern Idaho	1,500	0%	676	500 kV Single Circuit AC Line	$ 2,925	7.8%	$ 365
Victorville	1,650	10%	43	500 kV Single Circuit AC Line	$ 674	0.5%	$ 84
Wyoming	3,000	0%	1,030	500 kV Double Circuit AC Line	$ 5,796	11.8%	$ 722

In zones where there is a relatively balanced mix of solar and wind resources, E3 allows overbuild of resources within that zone up to 20% of the transmission line size. This overbuild reflects the fact that wind and solar resources typically generate at different times. Thus, an area with more diversified resources (for example, see Pisgah, Lassen South, and British Columbia in the table above) can develop resources beyond the assumed capacity of the line from that zone. The overbuild assumed for each zone is shown in the third column in the table above, and reflected in the "Assumed Line Capacity".

4. Cost and Performance Assumptions

E3 derives average cost and performance characteristics from the sites included in the RETI analysis, which provides site-specific cost information for sites within California. Generic cost estimates for installations within California are shown in the table below. All RETI resources, as well as the out-of-state hydro and geothermal resources, have site-specific data which is used when available. The generic cost estimates shown in the table below are applied to all installations for which E3 does not have site-specific data.

The qualifying capacity for wind is based on the 2009 Net Qualifying Capacity (NQC) values used by the California Independent System Operator (CAISO). E3 assumes a qualifying capacity of 20% for wind installations in northern California and 30% for all other areas. Solar PV capacity credit comes from NREL,[18] assuming horizontal placement at 10% penetration for distributed PV. The value for remote zones assumes two-axis tracking at 10% penetration, and as a result, has higher costs (including a cost penalty for transmission upgrades as discussed above) and a higher capacity factor.

Table 7. Generic Resource Costs

Operating Data	Biogas	Biomass	Geothermal	Hydro - Small	Solar PV	Solar Thermal	Wind	Gas CCCT
Nominal Heat Rate	11,566	14,749	-	-	-	-	-	6,924
Capacity Factor	85%	80%	87%	50%	24%	28%	33%	65%
Availability On-Peak (% of Nameplate)	100%	100%	100%	65%	77%	77%	29%	100%
Costs (California Average)								
Installed Capital Costs	$ 3,483	$ 4,951	$ 4,576	$ 3,636	$ 7,065	$ 4,924	$ 2,491	$ 1,249
Variable O&M ($/MWh)	$ 0.014	$ 15.857	$ 40.604	$ 5.129	$ -	$ -	$ -	$ 6.515
Fixed O&M ($/kW-yr.)	$ 160.19	$ 114.11	$ -	$ 19.58	$ 53.70	$ 80.55	$ 73.49	$ 15.17
Fuel Cost ($/MWh)	$ 24.36	$ 44.80	$ -	$ -	$ -	$ -	$ -	$ 71.37
Insurance ($/kW-yr.)	$ 17.42	$ -	$ -	$ 18.18	$ -	$ -	$ -	$ 6.25

E3 also developed regional cost multipliers to reflect differences in the costs of labor and materials across states and provinces. Cost multipliers were developed for both capital and operating and maintenance (O&M) costs, and are based on the State Adjustment factors developed by the U.S. Army Corps of

[18] Perez, et al., "Update: Effective Load-Carrying Capability of Photovoltaics in the United States," http://www.nrel.gov/pv/pdfs/40068.pdf, p.5.

Engineers.[19] These multipliers were then applied to the generic cost estimates to provide state- and resource-specific cost estimates.

Table 8. Regional Cost Multipliers by Region and Resource Type

Regional Cost Multipliers (US average = 1.00)	Biogas	Biomass	Geothermal	Hydro - Small	Solar PV	Solar Thermal	Wind	Gas CT	Fixed O&M
AB	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
AZ	0.975	0.953	0.971	0.950	0.980	0.945	0.977	0.948	0.964
BC	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
CA	1.089	1.170	1.105	1.178	1.073	1.199	1.081	1.186	1.130
CFE	0.955	0.915	0.947	0.911	0.964	0.901	0.959	0.907	0.935
CO	0.990	0.981	0.988	0.980	0.992	0.978	0.991	0.979	0.986
MT	0.980	0.962	0.977	0.960	0.984	0.956	0.982	0.959	0.971
NM	0.970	0.943	0.965	0.941	0.976	0.934	0.973	0.938	0.957
NV	1.045	1.085	1.053	1.089	1.036	1.099	1.041	1.093	1.065
NW	1.040	1.076	1.047	1.079	1.032	1.088	1.036	1.083	1.058
UT	0.980	0.962	0.977	0.960	0.984	0.956	0.982	0.959	0.971
WY	0.955	0.915	0.947	0.911	0.964	0.901	0.959	0.907	0.935

E3 uses a similar method to estimate the performance characteristics of the technologies where site-specific data was unavailable. Data from the RETI sites is rolled up into average performance metrics, which are applied to those resources for which site-specific data was unavailable. For those resources that did not have site-specific capacity factor estimates, E3 assigns a capacity factor based on the resource class. The capacity factor for each resource class (shown below) is based on the average capacity factor among sites in the RETI analysis in that class.

Table 9. Wind Capacity Factors by Resource Class

Wind Resource Class	Capacity Factor
Class 3	29%
Class 4	33%
Class 5	36%
Class 6	39%
Class 7	43%

5. Natural Gas and CO2 Allowance Price Forecasts

The natural gas fuel price forecast that E3 uses for the 33% RPS Implementation Analysis is based on the 2020 Henry Hub Natural Gas Price as traded on NYMEX, while the basis spread for delivery to California comes from the 2009 Market Price Referent (MPR).

The CO2 Price forecast comes from the 2009 MPR Analysis, and is based on an analysis performed by Synapse Energy Economics, Inc.[20]

[19] The state-by-state multipliers can be found in table A-3 of this document: http://140.194.76.129/publications/eng-manuals/em1110-2-1304/entire.pdf.
[20] The paper describing the Synapse analysis can be found here: http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf.

Table 10. Natural Gas and CO2 Price Assumptions

	Nominal (2020) Dollars			2008 Dollars*		
	2020 Base Case	Low Case	High Case	2020 Base Case	Low Case	High Case
Synapse 2020 Nominal CO2 Price Forecast ($/ton)	$ 42.46	$ 15.00	$ 100.00	$ 31.57	$ 11.15	$ 74.36
CO2 Gas Price Adder	$ 2.48	$ 0.88	$ 5.85	$ 1.85	$ 0.65	$ 4.35
Henry Hub Base Nominal Gas Price ($/MMBtu)	$ 8.46	$ 6.00	$ 13.50	$ 6.29	$ 4.46	$ 10.04
Adder for California Delivered to Generator (MPR)	$ 0.37	$ 0.37	$ 0.37	$ 0.28	$ 0.28	$ 0.28
Henry Hub Gas with CO2 Adder ($/MMBtu)	$ 10.94	$ 6.88	$ 19.35	$ 8.14	$ 5.11	$ 14.39
CA Gas Price Forecast w/ CO2, delivered to electric generators ($/MMBtu)	$ 11.32	$ 7.25	$ 19.72	$ 8.42	$ 5.39	$ 14.67
CA Gas Price Forecast w/o CO2, delivered to electric generators ($/MMBtu)	$ 8.83	$ 6.37	$ 13.87	$ 6.57	$ 4.74	$ 10.32

* - Nominal dollars are deflated using a 2.50% annual inflation rate to reach 2008 dollars

6. Financing Assumptions

In order to allow technologies to compete on an even playing field, E3 assumes that all resources are developed by independent power producers (IPPs) using a 20-year financing life as described in Table 10 below. E3 calculates the resulting 20-year levelized $/MWh power purchase agreement (PPA) price at a level that allows the IPP to achieve its target after-tax equity return. E3 assumes that each project is project financed. The solar PV and solar thermal resources have additional equity in their capital structure because without it, the investment tax credit and accelerated tax depreciation result in insufficient operating cash flows to cover debt service in some years.[21] The after-tax equity return for solar resources is lower due to the reduced debt share, which reduces the risk profile of the equity in that project, allowing IPPs to offer equity at a lower rate of return. E3 calculates the debt-equity ratio and return on equity for solar resources such that the pre-tax weighted average cost of capital (WACC) remains roughly constant across resources. The relevant financial assumptions for solar, non-solar, and transmission financing are shown in the table below.

[21] E3 assumed that IPPs would require a debt service coverage ratio of approximately 1.5.

Table 11. Financing Assumptions[22]

	IPP Financing Assumptions (Non-Solar)	IPP Financing Assumptions (Solar)	Transmission Financing Assumptions
All-In Tax Rate	41%	41%	41%
Economic Life (Years)	20	20	40
Debt Life (Years)	20	20	40
After-tax Equity Return	15.29%	13.25%	10.78%
Equity Share in Capital Structure	40%	55%	55%
Debt Share in Capital Structure	60%	45%	45%
Cost of Debt	7.27%	7.27%	5.96%
Pre-tax nominal WACC	10.48%	10.56%	8.63%
After-tax nominal WACC	8.70%	9.23%	7.54%

E3 assumes that existing federal tax incentives will be in place in 2020. Biomass, geothermal, and small hydro resources receive a production tax credit (PTC) of $0.01/kWh (in 2008 dollars), while biogas and wind resources receive a PTC of $0.02/kWh. Solar PV and solar thermal resources receive an investment tax credit of 30%, though E3 assumes that only 95% of the capital cost will be eligible to receive that credit. Black and Veatch ignored state tax incentives in developing their costs estimates.

Property tax was included in the fixed O&M estimates for renewable resources in the Black and Veatch analysis. E3 included a 1% property tax for solar photovoltaic installations.

E3 models geothermal, solar PV, solar thermal, and wind resources as eligible for the Modified Accelerated Cost Recovery System (MACRS) tax depreciation over a five year period. This means that for tax purposes, their cost is depreciated over five years instead of the 20-year assumption used for the remaining resources.

7. Calculation of RPS Need

For California and each of out of state zone included in the analysis, E3 calculates an RPS Need that represents the amount of renewable energy,[23] above existing levels, that each zone must procure to meet applicable standards. E3 takes the requirements in each zone from existing legislation, aggregating requirements for zones that span multiple state jurisdictions. For zones with a standard that goes into effect later than 2020, E3 estimates the need in 2020 based on a straight line interpolation between existing levels of renewables and

[22] Assumptions on the rates of return for equity and debt are taken from the “2008 Capitalization Rate Study” performed by the California State Board of Equalization, found at http://www.boe.ca.gov/proptaxes/pdf/2008capratestudy.pdf. IOU financing parameters are taken from the GHG Model. The Debt-to-Equity ratios were developed based on the GHG model, and adjusted to reflect the changing economic conditions.

[23] “Renewable energy” as defined here includes biogas, biomass, geothermal, small hydro (<30 MW), solar PV, solar thermal, and wind resources.

targets in the binding years. For those zones that do not currently have a Renewable Portfolio Standard or similar legislative requirement, E3 assumes a minimum 5% requirement in 2020. The BC Energy Plan calls for all new electricity projects in British Columbia to have zero net greenhouse gas emissions. To implement this, E3 removes all fossil fuel resources from the British Columbia zone supply curve, but allows BC to develop large hydro resources to meet load growth.

E3 bases the projected California retail sales in 2020 on the growth rates from the 2007 Energy Commission load forecast,[24] which does not include the water agencies (as they are not covered by the 33% RPS requirements). E3 takes the existing generation claimed from renewables from the 2007 CEC Net System Power report.[25] In 2007, California utilities claimed 27,063 GWh from renewables in the WECC, which E3 assumes will be available in 2020. The table below shows the calculation through which the need for renewables was determined for three different load cases. The load reductions in the "Low-Load Sensitivity" are based on the "Aggressive Policy" case in the GHG Model and the joint Energy Commission/CPUC Final Decision on Greenhouse Gas Regulatory Strategies.[26]

Table 12. Calculation of RPS Need

	20% Reference Case (GWh)	33% Reference Case (GWh)	Low-Load Sensitivity (GWh)
2020 Base Retail Sales	308,220	308,220	308,220
- Energy Efficiency			(18,919)
- Rooftop PV			(3,127)
- On-Site CHP			(9,771)
2020 Final Retail Sales	308,220	308,220	276,403
RPS Requirement	61,644	101,713	91,213
2007 RPS Eligible Resources	27,063	27,063	27,063
2020 RPS Need	**34,581**	**74,650**	**64,150**

The RPS Need calculated by E3 for the 33% RPS Implementation Analysis differs from the comparable "Net Short Calculation" developed by Black and Veatch for the RETI Phase 1B report.[27] E3 and Black and Veatch used different

[24] California Energy Commission, "California Energy Demand 2008 – 2018 Staff Revised Forecast," CEC-200-2007-015-SF2, November 2007.
[25] California Energy Commission, "2007 Net System Power Report," http://www.energy.ca.gov/2008publications/CEC-200-2008-002/CEC-200-2008-002.PDF, Table A-3.
[26] A more complete description of the E3 GHG "Aggressive Policy" case can be found at http://www.ethree.com/GHG/7%202020%20Base%20Case%20Input%20Summary%20v4.doc or in CPUC Decision 08-10-037.
[27] The description of the calculation used in the RETI Phase 1B report can be found at http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF.

methods for calculating the RPS Need (Net Short amount), but the biggest difference is the amount of energy that each analysis assumes available from RPS resources in 2007. The RETI Process assumed almost 13,000 GWh more from existing renewables, accounting for most of the difference between the two need calculations. RETI also assumed 4,200 MW of solar PV resources would be installed by 2020 as part of the California Solar Initiative/Go Solar California program with a capacity factor of 20%, which reduces the retail sales by 7,358 GWh and the Net Short calculation by 2,428 GWh.

Table 13. Comparison of RPS Need Calculation from the 33% RPS Implementation Analysis and the Net Short Calculation from RETI

	33% Reference Case (GWh)	RETI Phase 1B Net Short Calculation
2020 Total Consumption		334,169
- Wholesale Consumption		(12,299)
- Self-Generation (Non-PV)		(12,538)
- Self Generation (PV)*		(7,358)
2020 Final Retail Sales	308,220	301,974
33% RPS Requirement	101,713	99,651
2007 RPS Eligible Resources	27,063	39,941
2020 RPS Need	**74,650**	**59,710**

*** The RETI Phase 1B Report assumes the installation of 4,200 MW of Solar PV with a capacity factor of 20% by 2020**

8. Assumptions Regarding OTC Generation and Fossil Retirements

The California State Water Board has determined that generators employing Once-Through Cooling[28] ("OTC Generators") need to be shut down or repowered as non-OTC generators to continue operating, to prevent further damage to marine life. Since the rules were not yet developed when this analysis took place, E3 had to make judgments about the likelihood that a given OTC generator would be shut down, repowered, or allowed to continue operating.

E3 uses a list of OTC generators available from the CAISO[29] to determine which generators will be available in 2020, whether as a result of continued operation for reliability concerns or as a result of repowering. These determinations are based on a review of the capacity factor of the plants, their age, and whether the

[28] From the CPUC Report "Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System": "Once-through cooling is a technology that uses seawater to cool and re-condense superheated steam after it has been used to generate power and has significant impacts on marine organisms and ocean habitat."
[29] "Generating Units in CAISO Relying on Once-Through-Cooling," available at http://www.caiso.com/208b/208b8b2f329d0.pdf.

units were necessary to maintain local reliability. All units that were retired or repowered were assumed to do so between 2011 and 2019. The table below lists the OTC generating units in California, the capacity retired at each plant, and whether any of that capacity was repowered as non-OTC generation.

Table 14. Treatment of OTC Generators

	Total Nameplate Capacity (MW)	Capacity Factor	Retired Capacity (MW)	Repower or retrofit as CCGT (MW)	Repower or retrofit as CT (MW)	Retirement Date
Alamitos 1&2	350	3%	350			2016
Alamitos 3&4	668	13%	668			2016
Alamitos 5&6	992	10%	992			2019
Contra Costa	680	3%	680		600	2019
Diablo	2,240	95%	-			
El Segundo 1&2	-	0%	-		550	2015
El Segundo 3&4	670	11%	-			
Encina 1-5	929	15%	550		550	2016
Harbor	240	10%	-			
Haynes 1&2	444	10%	-			
Haynes 3&4	444	10%	-			
Haynes 5&6	682	10%	-			
Haynes 9&10	575	10%	-			
Humboldt Bay	105	46%	105		163	2011
Huntington	880	15%	-			
Mandalay	430	9%	-			
Morro	673	7%	673			2018
Moss 1-4	1,020	57%	1,020	1,020		2014
Moss 6&7	1,510	17%	-			
Ormond	1,516	3%	-			
Pittsburg	1,311	3%	682			2016
Portrero	207	29%	207			2012
Redondo 5&6	350	2%	-			
Redondo 7&8	963	7%	-			
Scattergood	803	10%	-			
SONGS 2	1,123	68%	-			
SONGS 3	1,109	69%	-			
South Bay	690	17%	690			2014
Total	***21,604***		***6,617***	***1,020***	***1,863***	

9. Energy and Capacity Balancing

Once the model selects a portfolio of renewable resources to meet the 33% RPS goal in 2020, it checks to ensure that there is sufficient energy and capacity in each of four time periods, low-load and high-load hours in both the summer and winter. The model first balances the energy in each time period by adding sufficient Combined Cycle Gas Turbines (CCGTs) to ensure the capability to meet energy demand in the time period during which there is the largest shortfall. CCGTs are assumed to operate at a 65% capacity factor.

Table 15. Sample Energy Balancing Calculation, 33% RPS Reference Case

Conventional Generation Added for Energy Balancing	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Required net additions for energy relative to 2008 Baseline (GWh)	-	3,607	7,258	10,953	14,693	18,477	22,307	26,184	30,107	34,078	38,096	42,163	46,280
Energy from New Renewable Generators (GWh)	-	-	6,424	13,312	16,430	35,661	35,661	35,661	48,325	48,325	54,269	59,800	73,637
Net Energy Required (GWh)	-	3,607	834	(2,359)	(1,737)	(17,184)	(13,354)	(9,477)	(18,218)	(14,247)	(16,172)	(17,636)	(27,357)
Cumulative CCGTs added for balancing (MW)	-	449	449	449	449	449	449	449	449	449	449	449	449

Once the model calculates the number of CCGTs required to meet energy needs, it checks to ensure that there is sufficient capacity to meet peak demand. A capacity shortfall is remedied by the addition of Gas Combustion Turbines (CTs) sufficient to meet peak demand plus a 17% capacity reserve margin.

Table 16. Sample Capacity Balancing Calculation, 33% RPS Reference Case

Conventional Generation Added for Capacity Balancing	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Required additions in dependable capacity (MW)	-	962	1,936	3,028	4,235	5,248	7,984	9,023	12,326	13,393	15,146	17,913	19,022
Dependable Capacity from New Renewable Generators (MW)	-	-	726	2,787	3,273	5,760	5,760	5,760	7,264	7,264	8,536	9,935	13,024
Capacity added from OTC Repowering (MW)	-	-	-	163	163	163	1,183	1,733	2,283	2,283	2,283	2,883	2,883
Capacity added from Energy Balancing (MW)	-	449	449	449	449	449	449	449	449	449	449	449	449
Cumulative CTs added for balancing (MW)	-	513	762	762	762	762	762	1,082	2,331	3,397	3,878	4,646	4,646

The model requires the California system to be balanced in every year between 2008 and 2020, and assumes that once built, balancing resources are available (and incurring costs) for the lifetime of the analysis.

Appendix B3

Transmission Studies Summary

1. Renewable Energy Transmission Initiative

The California Renewable Energy Transmission Initiative (RETI) was formed jointly by the CPUC, CEC, CAISO, and the POUs. RETI plans to identify the large-scale transmission projects necessary to meet State renewable energy and climate change goals. RETI is using a multi-phase modeling process to identify areas of high renewable potential. The RETI phase 1A[1] and 1B[2] reports identified areas of the state and adjoining regions having high densities of biomass, geothermal, solar, and wind resources. These areas are referred to as Competitive Renewable Energy Zones (CREZ). A majority of the CREZ zones are located within California. Phase 2 focuses on conceptual transmission planning to identify transmission projects needed to deliver renewable energy to consumers in a reliable manner while minimizing stress on the environment and which have the consensus support of a broad range of stakeholders. Phase 3 is intended to support the filing of applications to construct new transmission to renewable resource areas. At this time, RETI has released the Phase 2A[3] report and is working on the Phase 2A update. The RETI analysis also provides an assessment of renewable resources by location and technology type. Additionally, the RETI dataset is based on projects that have commercial interest.

2. California Independent System Operator

The California Independent System Operator (CAISO) is the planning authority for most of California's transmission system and develops, integrates, and plans transmission infrastructure. In this role, CAISO released the Report on *Preliminary Renewable Transmission Plans*.[4] The report indentified areas that will need additional electrical infrastructure including power plants, substations, and transmission to meet the California's renewable energy goals. CAISO staff evaluated multiple scenarios to develop conceptual transmission options needed to both a 20 percent RPS and 33 percent renewable goal. Some of the conclusions from the report are: 1) the completion of the Tehachapi Renewable Resources Transmission Project and the Sunrise Powerlink should allow California utilities to meet the 20 percent RPS goal; and 2) to meet the 33 percent goal by 2020, six additional large scale transmission projects would need to be built and brought on-line by 2020. The cost for building these transmission projects was estimated to be $6.5 billion (in 2008 dollars). A matrix of the proposed transmission projects can be found in table B2. In addition, CAISO created the 2020 Renewable Transmission Conceptual Plan based on inputs from the RETI process. This study evaluated the transmission and distribution infrastructure needed to connect 69,000 GWh per year from some of the CREZs to retail customers.

3. California Public Utilities Commission

The California Public Utilities Commission (CPUC) 33 percent *Renewable Portfolio Standard Implementation Analysis Preliminary Results*[5] report discusses the transmission needs to meet the 33 percent renewable energy goal. The CPUC staff considered four possible 33 percent renewable scenarios to assess the costs and timelines when different assumptions are made. In addition, a 20 percent renewables reference case was developed as a benchmark cost comparison and represents the most likely renewable energy mix in 2020 based on current California law and existing energy contracts. CPUC staff also evaluated an "all-gas" scenario that assumes no renewable development beyond 2007 and all new electricity demand is met with natural gas-fired generation.

The four 33 percent RPS scenarios considered in the study were:

- California's current renewable procurement path (reference case);
- The majority of the renewables from wind generation in California and Mexico;
- Large amounts of low cost renewable power from other western states and new multi-state transmission lines will be constructed; and
- Limited access to new transmission lines and the RPS will be satisfied by small-scale renewable generation that is either interconnected to the distribution system or is close to transmission substations.

As part of this analysis, the CPUC used a mix of 54 renewable energy zones that, depending on the scenario, would meet renewables goal. Some of the zones used in the evaluations include Tehachapi, Solano, Imperial North, Riverside East, Riverside East (incremental), Mountain Pass, Carrizo North, Needles, Kramer, Fairmont, San Bernardion-lucerne, Palm Springs, and Baja.

The study states that currently transmission requires an average of approximately eight years to get permit approvals and to build the transmission. Some of the reasons for the long project duration include:

- Potential significant environmental impacts that must be mitigated;
- A long and complex process to complete the environmental documentation;
- Challenges in applying for and obtaining the necessary land use and right-of-way permits; and
- Strong opposition from local groups.

If legal challenges are filed against the project, the project timeline could easily exceed the eight year timeline. CPUC staff believes that if transmission and generation reforms currently underway are successful, the planning and permitting timeline could be reduced. The study concludes that in the best case, the necessary transmission system modifications will be completed to allow the achievement of the 33 percent renewable goal by 2021. However, the study also states that with a streamline planning and permitting process, and the installation of a significant amount of direct generation, meeting the 33 percent RPS by the 2020 date is possible. Conversely, in the worst case, the revisions to the transmission system and planning and permitting process may never be fully completed and therefore, the 33 percent renewable goal would never be reached.

Finally, the study indicated that the investment for the transmission infrastructure would be approximately $12 billion for the 33 percent renewables goal and $4 billion for the 20 percent renewables goal for the reference cases.

4. California Transmission Planning Group

The California Transmission Planning Group (CTPG) is a coalition of transmission owners or transmission operators who operate under the WECC transmission planning regulations. The CTPG is conducting transmission-planning studies consistent with the principals of Federal Energy Regulatory Commission (FERC) order No. 890.[A] In addition, CTPG is determining the necessary revisions to the transmission system such that states will reliably satisfy their renewable energy standards, including California's 33% renewable electricity standard. The CREZ concept developed by RETI is incorporated into CTPG studies.[6] The CTPG analysis used four case studies to determine the location and amount of transmission needed to bring generation from CREZs to retail customers.

5. Western Governors' Association

The Western Governors' Association (WGA) and U.S. Department of Energy launched the Western Renewable Energy Zones (WREZ) initiative in May 2008. Participating in the initiative are representatives throughout the Western Interconnection, including 11 states, two Canadian provinces, and areas in northern Mexico. In June 2009, the WGA released the WREZ Phase 1 report[7] that mapped concentrated, high energy density renewable resources in the Western Interconnection's markets. The report included a Hub Map that shows the WREZ's state specific "hubs." The hubs indicate the regional utility scale renewable resource potential, based on the WREZ assumptions. The hubs are intended to help future WGA evaluations of interstate transmission lines. The phase 1 report indicates that the hub energy generation potential is greater than current Western Interconnection renewable standards requirements. Future WREZ project phases will include: developing transmission plans (Phase 2);

[A] http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

coordinating energy purchasing from the WREZs (Phase 3); and fostering interstate cooperation for developing energy generation and transmission (Phase 4).

6. Lawrence Berkeley National Laboratory

The Environmental Energy Technologies Division of Lawrence Berkeley National Laboratory (LBNL) evaluated the renewable energy generation and transmission needed to meet California's 33 percent renewable goal. In the study, titled the *Exploration of Resources and Transmission Expansion Decisions in the Western Renewable Energy Zone,*[8] LBNL staff evaluated the need for transmission infrastructure that would connect renewable generation in WREZ hubs to load zones. The model was developed by Black and Veatch, LBNL, and other energy experts. The study evaluated a base case and two alternate scenarios to determine how different constraints could impact the type and cost of renewable resources along with the cost and location of transmission. The studies found that the cost range of building transmission to meet a 33 percent renewable goal WECC-wide is between $22 and $34 billion, based on an average transmission length of 230-315 miles. In addition, the study indicated the use of tradable renewable energy credits (RECs) would decrease the total transmission cost by $17 billion. This study is the only one that considered REC trading as a method to comply with renewable energy goals. Furthermore, this study did not identify the transmission lines needed to specifically meet California's 33 percent renewable goal.

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