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**RESOURCE RANKING & SELECTION  
METHODOLOGY FOR  
33% RENEWABLES PORTFOLIO STANDARD  
IMPLEMENTATION ANALYSIS**

**Prepared for:  
California Public Utilities Commission  
Energy Division  
505 Van Ness Avenue  
San Francisco, CA 94102-3298**

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Prepared by:

Energy and Environmental Economics, Inc.  
101 Montgomery, Suite 1600  
San Francisco, CA 94104  
Phone: 415-391-5100  
Fax: 415-391-6500  
Web: <http://www.ethree.com>



Energy and Environmental Economics, Inc.

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## 1. RETI “net value” approach Overview

The 33% RPS Implementation Analysis constructs renewable resource portfolios by ranking individual projects and resource zones based on a “net value” approach adapted from the Renewable Energy Transmission Initiative (RETI) study.<sup>1</sup>

As described in the RETI Phase 1B Report, the RETI analysis ranks zones based on the weighted average “rank cost”, or cost less value, for projects within the zone. The RETI “rank cost” consists of four components: (1) levelized cost of energy (including costs of interconnection to the grid), (2) levelized incremental transmission cost, (3) energy value, and (4) capacity value.

This 33% RPS Implementation Analysis extends that ranking methodology by incorporating four additional components into the “net value” rank: (1) deemed integration cost for intermittent resources, (2) transmission and distribution (T&D) avoided costs for distributed resources, (3) an adjustment for anticipated permitting challenges (environmental score), and (4) an adjustment for projects already on investor-owned utility (IOU) RPS Project Lists in the CPUC Energy Division Database.

The table below shows the components of the project ranking formula used in the RETI analysis and in the 33% RPS Implementation Analysis. Components that have been added directly to the project ranking in the 33% RPS Implementation Analysis are shown in **bold**.

**Table 1 : Project Ranking Formula**

33% RPS Implementation Analysis
+ Levelized Cost of Energy
+ Levelized Transmission Cost per MWh
+ Interconnection (Gen-tie) Cost
+ <b>Deemed Integration Cost</b>
- Energy Value
- Capacity Value
- <b>T&amp;D Avoided Costs</b>
+ <b>Adjustment for Environmental Score</b>
+ <b>Adjustment for ED RPS Projects</b>
= <b>Final Project Rank ("Net Value")</b>

<sup>1</sup> See Black & Veatch, *Renewable Energy Transmission Initiative Phase 1B Final Report*, December 2008, Prepared for RETI Coordinating Committee (<http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-PF.PDF>). The 33% RPS Implementation report also uses data and assumptions from the E3 GHG Calculator developed for the CPUC (See [http://www.ethree.com/CPUC\\_GHG\\_Model.html](http://www.ethree.com/CPUC_GHG_Model.html)).

Overall, the focus of this analysis is on “plausible” resource portfolios, and there is no warranty that this method will result in an “optimal” or “likely” portfolios. The following sections describe the individual components of the “net value” ranking, and how these rankings are used to select projects within each zone and zones for each portfolio.

## 2. Levelized cost of energy

The levelized cost of energy (LCOE) used for project ranking does not represent actual negotiated contract prices but instead reflects the developer cost to build and operate a renewable energy project with a reasonable profit. The LCOE used for this cost component represents the cost of generating the energy and excludes any transmission or other grid-related costs. The “Inputs & Assumptions” whitepaper describe the technology and financing assumptions used to calculate this cost. Figure 13 of the 33% RPS Implementation Analysis Preliminary Results report shows the range of levelized costs for each technology based on from these assumptions.<sup>2</sup>

## 3. Levelized, per-MWh incremental transmission costs

The ranking of each project includes the cost per MWh of incremental transmission that the project would require. E3 calculates this levelized transmission cost as:

$$\frac{\text{Cost per kW-yr of transmission to the resource zone of the project}^3}{\text{divided by}} \\ \text{Expected kWh of energy generated per kW of project capacity}^4$$

For projects outside of California, the lowest cost resources are first used to meet local state energy and RPS requirements, and any remaining resources are available for export to California. When selecting resources for local use by other states, resource rankings exclude the levelized cost of incremental transmission to California.

## 4. Interconnection cost

Interconnection (or gen-tie) cost, represents the cost of facilities to transmit the energy from the generator to the backbone transmission system. For projects from the RETI analysis, interconnection costs were taken directly from the RETI data. For projects from the E3 GHG Calculator, interconnection costs per kW of project capacity were calculated as:

$$\frac{\text{Capital cost of \$2000/kW-mile (in 2008 Dollars)}}{X} \\ \text{Distance (in miles) from the project site to the nearest bulk transmission line}$$

<sup>2</sup> See Appendix B, page 73 of the 33% Implementation Analysis Preliminary Results, (<http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf>). The 33% Implementation Analysis utilizes the RPS Calculator, a Microsoft Excel spreadsheet model available on the CPUC RPS website (<http://www.cpuc.ca.gov/renewables>).

<sup>3</sup> Transmission costs for each zone are described in the section titled “Transmission Cost and Sizing Assumptions” of the whitepaper titled “Inputs & Assumptions to 33% RPS Implementation Analysis.”

<sup>4</sup> The energy generation per kW of capacity is calculated as the project’s capacity factor times 8,760 hours per year.

This interconnection cost per kW was then levelized to a per-MWh cost based on capacity factor of the project.

## 5. Deemed integration cost

For the GHG Calculator model developed for the CPUC,<sup>5</sup> E3 had conducted a regression analysis based on 32 estimates of wind integration costs from ten studies for North American utilities. Results of this regression indicated how increases in wind's share of total control area generation will raise the cost per MWh for hourly wind integration. These regression results are used in the 33% RPS Implementation Analysis to calculate the final integration cost of a complete resource portfolio.

For ranking projects and resource zones, however, E3 used a flat \$7.50/MWh for computational efficiency in this analysis. This value is calculated by using the regression described above to estimate interconnection costs for an intermittent resource penetration of 40%. This estimate assumes a high penetration of intermittent resources and is selected to estimate conservatively the net value of intermittent resources when ranking projects within a zone.

The California ISO is developing a full network model of the 33% RPS Reference Case, which can be used to improve the transmission cost estimates. The California ISO will also provide an estimate of the resources needed to reliably integrate intermittent technologies. This information will be used to update the 33% RPS cost information in Phase 3 of this analysis.

## 6. Less: Energy value

The energy value of a project (in \$/MWh) is a positive benefit produced from developing the project.

The model calculates energy value as:

$$\begin{aligned} & \text{2020 delivered fuel price for natural gas (gas) in California} \\ & \quad \text{(in 2008 Dollars per million British Thermal Units (MMBTU))} \\ & \quad \quad \quad X \\ & \text{Implied heat rate of energy for the technology (in MMBTU/MWh)} \end{aligned}$$

The 33% RPS Implementation Analysis uses a Base Case assumption for 2020 delivered fuel price for gas in California of \$8.42/MMBTU. This value is based on the California Market Price Referent (MPR) methodology,<sup>6</sup> as shown in Table 2 below. This amount includes an adder of \$1.85/MMBTU for the CO<sub>2</sub> content of the gas, which is based on a CO<sub>2</sub> allowance price of \$42.46/tonne (in 2020 dollars), the same value used for calculating the 2009 MPR.

<sup>5</sup> See <http://www.ethree.com/GHG/28%20Wind%20Integration%20Costs%20V2.doc> for documentation of the wind integration methodology used for the E3 GHG Calculator.

<sup>6</sup> See CPUC Decision 08-10-026.

**Table 2: 2020 Delivered Fuel Price for Gas in California based on MPR methodology**

Component	2020 Dollars	2008 Dollars	Source
2020 NYMEX Gas Futures Price at Henry Hub	\$8.46	\$6.29	NYMEX
+ Gas Basis Spread for Delivery to California Generators	\$0.37	\$0.28	2009 MPR
+ CO2 Content Adder to Gas Price	\$2.48	\$1.85	2009 MPR
<b>= 2020 Delivered Fuel Price for Gas in California</b>	<b>\$11.32</b>	<b>\$8.42</b>	

Implied heat rates may vary by region, but for Phase 1 and 2 of this analysis, the heat rate used for calculating energy values in all zones is based on historical data for the South of Path 15 (SP-15) zone in Southern California. The table below shows the heat rate used for each technology.

**Table 3: Implied Heat Rate of Energy by Technology for Energy Value Calculations**

Resource Type	Implied Heat Rate (MMBTU/MWh)
Baseload (Conventional)	8.520
Biogas	8.520
Biomass	8.520
Geothermal	8.520
Hydro - Small	8.387
Solar PV	9.670
Solar Thermal	9.670
Wind	8.396

The heat rate used is 8.520 MMBTU/MWh for baseload technologies (including biomass, biogas, and geothermal projects). For solar PV and solar thermal generation, E3 uses a higher heat rate to calculate the energy value because these technologies will generate a higher portion of their energy during the middle of the day, when peak hours of demand for electric generation occur. Conversely, wind resources have slightly lower heat rates because wind's hourly output profiles are slightly higher during the night in California. Similarly, small hydro facilities have a lower heat value because they typically generate more heavily during non-peak seasons in California.

## 7. Less: Capacity value

The capacity value of a project (in \$/MWh) is a positive benefit that represents the value of the reliable capacity that the project can provide California to meet power demands during system peaks. It can also be viewed as the cost of capacity purchases that can be avoided by developing a particular renewable resource. Capacity value is higher for conventional resources than for certain intermittent resources such as wind that are not always available to produce energy during system peaks.

For each project, E3 calculates capacity value as:

$$\text{Annual net capacity cost of a new gas combustion turbine (CT) plant} \\ \times \\ \text{Reliable capacity rating of project (based on technology \& location)}$$

The annual net cost of a new gas CT represents the capacity payment per kW-yr that a CT would need to receive to earn its targeted return. In the model, it is calculated as the sum (in \$/kW-yr) of annual fixed costs for a new CT (including taxes and insurance), less the expected energy market revenues the plant would earn. The table below shows the values used to calculate this annual net cost.

**Table 4: Calculation of Annual Net Capacity Cost of New Gas CT (2008 Dollars)**

Cost component	\$/kW-yr
Capital Costs, Taxes, & Insurance	\$119.32
+ Fixed O&M	\$17.07
- Expected Energy Market Revenues	(\$52.43)
<b>= Annual net capacity cost of new gas CT</b>	<b>\$83.96</b>

The reliable capacity rating of a project is the percentage of the project's nameplate capacity that a utility can rely on to be available during peak demand hours. The reliable capacity rating for each technology appears in the table below.

**Table 5: Reliable Capacity Rating Used for Capacity Value Calculation**

Resource Type	Reliable Capacity Rating
Conventional	100%
Biogas	100%
Biomass	100%
Geothermal	100%
Hydro - Small	65%
Solar PV (non-distributed)	65%
Solar PV (distributed)	65%
Solar Thermal	70 to 87%
Wind (N. California Zones)	20%
Wind (All Other Zones)	30%

The reliable capacity rating is 100% of nameplate capacity for conventional, large hydro, and geothermal resources. For small hydro and solar PV (except for distributed solar) projects, reliable capacity is 65%. Distributed solar is assigned a slightly lower reliable capacity of 51% of nameplate, because the output of the distributed solar must be used on the particular distribution feeder on which it is located, and cannot be used to meet demand in other locations.

Hourly wind profiles indicate that projects in Northern California (specifically the Lassen North, Lassen South, and Solano resource zones in the model) provide a lower amount of output during peak hours for California load, so wind in these zones has been assigned a capacity value of 20%. Wind resources in all other zones receive the generic technology rating value of 30% reliable capacity for calculating project capacity value. Finally, solar thermal resource capacity values are taken directly from the RETI analysis and vary between 70% and 87% based on solar insolation levels in the zone of the project during summer heavy load hour (HLH) periods.

## 8. Less: T&D Avoided Costs

Wholesale Distributed generation (WDG) resources are small-scale generation resources interconnected at the sub-transmission system or the distribution system. When located on a constrained part of the distribution system, these resources can provide additional value by allowing utilities to avoid or defer investment upgrades in transmission or distribution capacity that would otherwise be needed.

For ranking projects in this analysis, these T&D avoided costs are included as a positive value (in \$/MWh) produced by WDG projects. This value varies by generation technology and by the location of the project on the utility system. For this analysis, avoided cost assumptions were based on statewide average values developed as part of energy efficiency avoided costs proceedings,<sup>7</sup> and are listed in the table below.

**Table 6: T&D Avoided Costs of WDG Resources by Interconnection Point**

WDG Interconnection Point	Avoided Costs to Reference Point (\$/kW-yr)			
	Distribution	Subtransmission	Transmission	Total
Behind the Meter	\$35	\$10	\$0	\$45
On Distribution Feeder	\$35	\$10	\$0	\$45
Low-side of Distribution Substation	\$35	\$10	\$0	\$45

Resources located behind the meter, on the distribution feeder, on the low-side of the distribution substation all received a T&D avoided cost of \$45/kW-yr (consisting of \$35/kW-yr for avoided distribution costs plus \$10/kW-yr of avoided transmission costs). These values are converted to a \$/MWh value based on the WDG project's capacity factor.

In addition to these T&D avoided costs, non-rule 21 PV installations that are installed at the low-side of the subtransmission substation<sup>8</sup> are assumed to incur additional network transmission costs of \$68/kW-yr, which is added to the overall resource ranking. This additional cost is not evaluated in the energy efficiency avoided cost proceedings but was estimated directly based on the equipment and construction costs associated with a step-up transformer that would be required to accommodate a PV project interconnecting at this point on the utility system.

## 9. Adjustment for Environmental Score

Each project considered in this analysis is assigned an environmental score of 1, 2, or 3, based its expected permitting difficulty, with 1 representing the lowest level of permitting difficulty. Environmental scoring is described in further detail in a separate whitepaper by Aspen Environmental Group.

This analysis adjusts the project ranking upward for projects with environmental scores of 2 and 3 in most scenarios. The table below shows the adjustment used for each score.

<sup>7</sup> See Energy Efficiency Avoided Costs proceedings, R.04-04-025.

<sup>8</sup> Projects of this type are incorporated from the RETI data.

**Table 7: Adjustment for Environmental Score**

Environmental Score	Adjustment to Project Rank (\$/MWh)
1	\$0
2	\$5
3	\$10

For the High Out-of-State Delivered Case, no adjustment for environmental scoring was applied to the project ranking due to lack of comparable data quality on the permitting challenges of certain out-of-state projects.

## 10. Final Project Rank

Projects from the Energy Division (ED) RPS database have been incorporated into this analysis using a special method described in the next section. For all other projects, the final project rank is calculated as the sum cost components listed above less the energy, capacity, and T&D values of the projects.

The table below shows an example of the final project ranking calculation for two projects in the Imperial North zone. Both of these projects were taken from the RETI project database.

**Table 8: Examples of Final Project Ranking Calculation**

	PROJECT A	PROJECT B
RETI Project ID	geo_4	st1800
Name	Brawley	st1800
Type	Geothermal	Solar Thermal
Total Available Capacity	160	200
Capacity Factor	80%	29%
Total Available Energy	1,121	514
	PROJECT RANKING COMPONENTS (\$/MWH)	
Busbar Cost (LCOE)	\$88.58	\$171.95
Total Transmission Cost to CA	\$12.87	\$35.08
Interconnection Costs	\$1.72	\$1.73
Integration Costs	\$0.00	\$0.00
Capacity Value	(\$14.23)	(\$28.09)
Energy Value	(\$71.70)	(\$81.37)
Avoided T&D Costs	\$0.00	\$0.00
Permitting Risk (SCORE 1 to 3)	1	2
Adjustment for Permitting Risk	\$0.00	\$5.00
<b>Final Project Ranking</b>	<b>\$15.52</b>	<b>\$102.56</b>

Example Project A in the table is a geothermal project in Brawley, California. The project has an estimated busbar levelized cost of energy (LCOE) of \$88.58/MWh and would cost \$1.72/MWh for interconnection to the grid. The Imperial North zone has an expected incremental transmission capital cost of \$1.085 Billion for 1,500 MW of capacity. Based on this value and the Brawley geothermal project's capacity factor of 80%, a total of \$12.87/MWh in incremental transmission cost is added to the Brawley project's ranking. There are no integration costs because it is not an intermittent resource.

As a baseload technology in the Imperial North zone, this geothermal project would provide \$14.23/MWh in capacity value and \$71.70/MWh in energy value. These two positive benefits are thus subtracted from the project rank. The project has a permitting risk level of 1, so no additional adjustment for permitting risk is added to the project ranking. These components result in an overall project ranking of \$15.52/MWh for the project, the lowest ranking for projects in the Imperial North zone.

Example Project B is a 200 MW solar thermal project located in the Imperial North Zone. Project B generates more heavily in peak hours and thus has a greater capacity and energy value than Project A. This value, however, is offset by Project B's significantly higher LCOE at the busbar (\$171.95/MWh), as well as other costs such as transmission and adjustment for environmental permitting risk. Together, these factors produce a final ranking cost of \$102.56/MWh. Project B would only be selected for the zone after the Brawley geothermal project and all other lower ranked projects in the zone have been included.

## 11. Incorporation of CPUC ED Database projects

The CPUC Energy Division maintains a database (ED Database) of renewable energy projects representing approximately 56 Terawatt hours (TWh) of electricity that the IOUs have selected through RPS solicitations. 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 analyses by enabling it to take advantage of information about commercial interest in specific new renewable projects.

As of January 2009, the database contains over 200 projects from IOU applications in various stages of development. While specific details of the projects are confidential, the table below summarizes the number of projects by technology and contract stage.

*Table 9: Number of Projects in ED Database by RPS Contract Status*

Resource Type	Status					Total
	Delayed	On Schedule	Operational	Pending Approval	Short Listed	
Bio gas		9	11		11	31
Biomass	9	1	8	4	12	34
Geothermal	3	5	10		8	26
Hydro - Small		2	4		2	8
Solar PV		7		2	27	36
Solar Thermal	1	12		4	25	42
Wind	6	7	13	4	25	55
<b>Total</b>	<b>19</b>	<b>43</b>	<b>46</b>	<b>14</b>	<b>110</b>	<b>232</b>

The Energy Division has rated the completion risk of each project as low-risk, medium-risk, or high-risk, based on the following factors: site control, fuel supply procurement risk, equipment procurement risk, financing status, developer experience, and Federal, state, and local permitting risk.. For this analysis, a slight change was made to the categorization of projects. The new grouping contains three categories:

**Category A:** Contract approved and not rated “high risk”

**Category B:** Short-listed or pending approval and not rated “high risk”

**Category C:** All projects rated “high risk”, regardless of status.

The tables below show the total MW and GWh totals by technology and category.

**Table 10: MW Capacity of ED Database Projects by Category**

Capacity (MW)	Category A	Category B	Category C	Total
Biogas				30
Biomass				407
Geothermal				459
Hydro - Small				40
Solar PV				3,638
Solar Thermal				8,807
Wind				5,592
<i>Total</i>	3,455	14,029	1,488	18,973

**Table 11: GWh of Energy of ED Database Projects by Category**

Energy (GWh)	Category A	Category B	Category C	Total
Biogas				320
Biomass				2,709
Geothermal				2,931
Hydro - Small				126
Solar PV				7,774
Solar Thermal				24,807
Wind				18,282
<i>Total</i>	11,690	39,131	6,127	56,948

To integrate ED database projects into this study, we first matched each project to a particular resource zone based on location.<sup>9</sup> Within each zone, we place all ED database projects at the top of the project list to ensure that these projects will be the first selected for that zone.

As described in the following section, the model assigns each zone an overall ranking, which is calculated as the weighted average of all projects selected from that zone. When calculating this overall zone ranking, we add Category A projects to the zone with a ranking cost of zero. In essence, these project costs are treated as “sunk” for the purpose of zone ranking. This approach improves the overall ranking of the zone by lowering the weighted average rank of the projects in the zone, particularly if the ED database project represents a significant portion (for example, greater than 50%) of the renewable energy generated by projects from that zone.

For Category B and Category C projects, the ranking depends on the RPS Case. In the 33% RPS Reference Case, Category B projects are assigned a project ranking using zero cost. Category C projects are assigned project rankings based on the generic technology costs used for projects

<sup>9</sup> It should be noted that we did not undertake a detailed mapping of ED Database projects to RETI projects; hence, there may be some overlap of potential projects between the two sources. In addition, renewable energy projects that came online in late 2007 and 2008 may not be represented. Finally, while the analysis incorporates project information from IOU solicitations, it does not include information about new and projected municipal and cooperative utility renewable energy projects.

from data sources other than the ED RPS database, as described in the previous sections. This method still ensures that Category C projects rises to top of zone list, but it does not necessarily improve zone ranking.

The table below identifies how each project category is treated under different RPS Cases.

**Table 12: Methodology used for ED RPS Database Projects Costs for Zone Ranking by Case**

RPS Case	Category A	Category B	Category C
All-Gas Scenario	Generic Cost	Generic Cost	Generic Cost
20% RPS Reference Case	Zero Cost	Zero Cost	Generic Cost
33% RPS Reference Case	Zero Cost	Generic Cost	Generic Cost
High Wind Case	Zero Cost	Zero Cost	Generic Cost
High Solar Case	Zero Cost	Zero Cost	Zero Cost
High Out-of-State Delivered Case	Zero Cost	Zero Cost	Generic Cost
High DG Case	Zero Cost	Zero Cost	Generic Cost
Solar PV Cost Reduction Sensitivity	Zero Cost	Zero Cost	Zero Cost
High Gas and CO2 Price Sensitivity	Zero Cost	Generic Cost	Generic Cost
Low Gas and CO2 Price Sensitivity	Zero Cost	Generic Cost	Generic Cost
Low Load Sensitivity (33% RPS)	Zero Cost	Generic Cost	Generic Cost

## 12. Ranking and Selection of Project and Zones

Portfolio selection involves a three step process utilizing the project ranking described in previous sections. The steps are:

1. **Select the lowest ranked projects in each zone to fill the designated size of transmission to that zone.**
2. **Calculate each zone's overall ranking as the weighted average ranking for projects selected from that zone.**
3. **Selects the zones with the lowest overall ranking until the total amount of renewable energy added fills the RPS need.**

Each resource zone is given a predetermined project size based on the expected amount of transmission to the zone. As noted above, projects from the CPUC ED Database within each zone are selected first, and then the lowest ranked projects from other data sources are selected until the zone's capacity limit is reached.<sup>10</sup>

After the resources within each zone are selected, the model calculates the zone's overall ranking as the weighted average ranking for all projects selected from that zone. Then, the lowest ranked zones are selected until California's RPS requirements are fulfilled.

<sup>10</sup> The production simulation modeling and the California ISO's transmission and integration studies require specific projects in specific locations. Selection or omission from the portfolios in this study should not be construed as an endorsement or rejection of a specific project.

### 13. Fixed 20% RPS case

The 20% RPS Reference Case was developed to serve as a point of comparison to the incremental cost of meeting a 33% RPS under different portfolios. The resources selected in the 20% RPS are automatically also selected in all other RPS cases (except the All-Gas Scenario), ensuring a consistent starting point for all cases.

The 20% RPS Reference Case reflects current state law and utility procurement and assumes that California utilities procure only enough resources to maintain the current statutory target of a 20% RPS in 2020. This case focuses primarily on resources that can be integrated through new transmission corridors that are already approved by the CPUC or are expected to be added in the near term such as Tehachapi and Sunrise.

The Energy Commission's 2007 Integrated Energy Policy Report (IEPR) load forecast was used to project electricity sales to 2020. Utilities procure 35 TWh of additional renewables to meet a 20% RPS target by 2020.

Table 13 and

Table 14 (reproduced from Appendix C of the 33% RPS Implementation Analysis Preliminary Results report) show the resources zones selected in the 20% RPS Reference Case and the incremental resource mix that results from developing these zones.

**Table 13: Resource Zones Selected in 20% RPS Reference Case**

Resource Zones Selected in 20% RPS Reference Case		
	MW	GWh
Tehachapi	3,000	8,862
Distributed CPUC Database	525	3,118
Solano	1,000	3,197
Out-of-State Early	2,062	6,617
Imperial North	1,500	9,634
Riverside East	1,350	3,153
<b>Total</b>	<b>9,437</b>	<b>34,581</b>

**Table 14: Resource Mix in 20% RPS Reference Case**

Resource Mix – 20% RPS Reference Case						
	In-State		Out-of-State		Total	
	MW	GWh	MW	GWh	MW	GWh
Biogas	30	223	-	-	30	223
Biomass	241	1,687	87	610	328	2,297
Geothermal	1,240	9,515	58	445	1,298	9,959
Hydro - Small	22	95	15	66	37	161
Solar PV	830	1,774	-	-	830	1,774
Solar Thermal	996	2,431	-	-	996	2,431
Wind	4,016	12,240	1,902	5,497	5,917	17,737
<b>Total</b>	<b>7,375</b>	<b>27,965</b>	<b>2,062</b>	<b>6,618</b>	<b>9,436</b>	<b>34,582</b>

## 14. Case Definitions

Each RPS Case included in the analysis is selected to highlight sensitivity to a particular issue or uncertainty. Each case uses different assumptions about the availability and desirability of particular resources, which impact the relative rankings of projects and zones, resulting in different final resource portfolios for each case.

Table 15 below describes the motivation of each case and how the portfolios were developed. A High Solar Case was also developed and shared with the working group, but the case was not included in the report because it was highly similar to the 33% RPS Reference Case.

**Table 15: RPS Case Description**

RPS Case	Description
<b>All-Gas Scenario</b>	Designed to show the overall change in the California electricity system by 2020 if no additional renewable resources are built after 2007. Results in 16.7% increase in average electricity costs per kilowatt-hour from 2008 to 2020.
<b>20% RPS Reference Case</b>	Utilities procure 35 TWh of additional renewables to meet a 20% RPS target by 2020. Focuses primarily on resources that can be integrated through new transmission corridors that are already approved by the CPUC or are expected to be added in the near term such as Tehachapi and Sunrise.
<b>33% RPS Reference Case</b>	Utilities procure 75 TWh of additional renewables to meet a 33% RPS target by 2020. There is heavy emphasis on projects that are already either contracted or short-listed with California IOUs, which includes a significant proportion of solar thermal (7,200 MW) and solar photovoltaic (3,200 MW) resources.
<b>High Wind Case</b>	Assumes less reliance on in-state solar thermal and more reliance on the less expensive wind resources in California and Baja. Replaces most of the solar resources in the 33% RPS Reference Case with wind resources in California and Mexico. Instead of relying on the higher cost solar thermal resources that are heavily represented in recent IOU solicitations, this case represents the lowest cost resources that can be developed in-state without assuming major, new interstate transmission.
<b>High Out-of-State Delivered Case</b>	Allows construction of new, long-line, multi-state transmission to allow California utilities to procure large quantities of low-cost wind and geothermal resources in other western states. Does not use tradable renewable energy certificates as a compliance tool. Thus, all out-of-state electricity is delivered to California. The case includes a 3,000 MW transmission line bringing wind energy from Wyoming and a 1,500 MW transmission line bringing principally geothermal resources from northern Nevada.
<b>High DG Case</b>	Assumes that it would be difficult or impossible to construct new, high-voltage transmission projects to accommodate renewable resources, beyond those lines assumed for the 20% RPS Reference Case. Instead, extensive, smaller-scale renewable generation is located on the distribution system and close to substations. Intended to examine the implications of the state relying heavily on distributed resources such as solar PV to meet a 33% RPS.
<b>Solar PV Cost Reduction Sensitivity</b>	Assumes the thin-film cost sensitivity included in the RETI Phase 1B report, and assumes that market transformation reduces the installed cost from approximately \$7/Watt-equivalent (W-e) today for crystalline solar PV to \$3.70/W-e for thin film solar PV by 2020.
<b>High Gas and CO2 Price Sensitivity</b>	Assumes 2020 gas price of \$13.50/MMBtu at Henry Hub (\$10.31/MMBtu in 2008 dollars delivered to California generators) and CO2 allowance price of \$100/tonne (\$74.36 in 2008 dollars). Highlights that while higher gas and CO2 allowance prices lower the relative cost of achieving RPS goals, they exert an upward effect on electricity costs overall.
<b>Low Gas and CO2 Price Sensitivity</b>	Assumes 2020 gas price of \$6/MMBtu at Henry Hub (\$4.74/MMBtu in 2008 dollars delivered to California generators) and CO2 allowance price of \$15/tonne (\$11.15 in 2008 dollars). Results in lower incremental cost impact of achieving 33% RPS.
<b>Low-Load Sensitivity</b>	Developed to test the interactive effects between aggressive demand-side measures and a 33% RPS. Assumptions based on the Accelerated Policy Case scenario presented in the GHG Calculator and described in the joint Energy Commission/CPUC Final Decision on Greenhouse Gas Regulatory Strategies. The Accelerated Policy Case has lower electric demand and lower retail sales than the 2007 IEPR load forecast used in the 33% RPS Reference Case. A low-load scenario could also result from other factors, such as an economic slowdown.