California's Renewable Energy Goals—
Assessing the Need for Additional Transmission Facilities

March 2009

Introduction

State agency and utility company planners identify large-scale solar, wind, geothermal and biomass projects as providing the fastest, most feasible and cost-effective path toward meeting state renewable energy and climate change goals. In California, the highest quality renewable resources remaining to be developed are concentrated in relatively small geographic regions outside urban areas. Providing access to these regions will require new transmission lines. California's Renewable Energy Transmission Initiative (RETI) was formed to identify the optimal set of such facilities.

Proponents of small-scale distributed technologies and concerned citizens, in California and across the country, argue that faster deployment of photovoltaic (PV) systems, expanded energy efficiency programs and other new technologies could avoid or reduce the need for large remote renewable generating projects and associated transmission. Comments received on the RETI Phase 1B Final Report, for example, question the need for remote renewable generation-transmission development.

This paper summarizes key drivers of electric demand and supply underlying planning to meet state goals. It provides a framework for assessing the extent to which such planning can reasonably rely on different assumptions about deployment of small-scale distributed generation in contrast to large-scale generation-transmission development.

RETI activities are based on the judgment that it is prudent to plan today for large-scale generation-transmission development, even if such facilities are later found not to be necessary and are never built. This paper outlines but does not defend the assumptions behind such planning. Instead, it is intended to provide an objective presentation of energy demand and supply fundamentals that all reasonable planning must take into account.

The first section of the paper reviews the scale of California's renewable energy goals and the planning assumptions underlying the formation of RETI. The paper then presents information on population growth and demand for electricity; factors affecting the expansion of energy efficiency and demand response programs; drivers of accelerated deployment of distributed PV; and the cost of meeting RPS targets with distributed vs. remote renewable resources. The final section of the paper offers a framework for assessing the prudence of planning approaches. An Appendix explains calculation of the renewable Net Short, the amount of new renewable energy the state must plan to make available.

1. California Renewable Energy Goals; RETI Mission and Planning Assumptions

Current law requires 20% of all retail electricity sold to California consumers to be generated from qualified renewable energy resources by the year 2010. State policy embodied in the Energy Action Plan adopted by the CPUC, Energy Commission and Governor Schwarzenegger increases this fraction to 33%.

In 2007, renewable energy supplied California consumers with 35,545 gigawatt-hours (GWh) of electric energy, approximately 12% of all electric energy sold.[1] As explained in the Appendix, supplying 33% of the state retail electricity from renewable resources in the year 2020 will require 59,700 GWh of new, additional renewable generation to be in service by that year. This is referred to as the renewable Net Short.

RETI was formed in 2007 to identify generation development areas and the transmission to access them, in ways that minimize both environmental and economic cost.[2] RETI is a voluntary statewide planning collaborative. It has no authority to determine the need for generation or transmission facilities, or to determine whether such facilities meet the requirements of CEQA and/or NEPA.[3]

The RETI initiative starts from these assumptions:

- Large-scale generating resources may prove to be necessary to meet the state's RPS and climate change goals;
- Such resources require new transmission facilities to access them;
- Transmission development takes seven-ten years, from preliminary planning through environmental studies, permitting and approval, to final design and construction;
- While development of other resources may reduce the quantity of large-scale resources needed, failure to begin planning now forecloses the opportunity to deploy large-scale generation that may be found to be necessary;
- It is better to plan and not build, than not to plan and be unable to build.[4]

Given the long lead times associated with transmission development, plans developed by RETI are unlikely to be operational before about 2015. If the RETI estimate of the renewable net short is approximately correct and California is to meet its energy goals, planning for the transmission required must begin at once.

New facilities identified by RETI which future events render unnecessary need not be constructed. Nevertheless, the RETI Stakeholder Steering Committee

[1] One gigawatt-hour is equivalent to one million kilowatt-hours (kWh). This value does not include electricity generated by individual customers for their own use.

[2] The RETI Mission statement, information about the formation of RETI, its reports, meetings, and activities, and contact coordinates for members of its Stakeholder Steering Committee are available on the RETI website: www.energy.ca.gov/reti.

[3] California Environmental Quality Act and the National Environmental Policy Act.

[4] Deferring the start of transmission planning also runs the risk of later forcing the state into rushed development that could greatly increase the cost and decrease the ability to minimize environmental impacts of eventual development.

(SSC) believes that the current estimate of the renewable net short is an appropriate value to be used for prudent transmission planning purposes.

2. Demand for Electricity and CA Population Growth

Building and appliance standards and a range of energy efficiency programs have been successful in keeping per capita electric consumption flat for more than 20 years. Despite this significant achievement, state electric demand has grown along with population. This section describes the dynamics involved.

Historical Electric Energy Consumption in California

Consumption of electric energy in California has grown with population since 1980 at an average annual rate of 2.0%, as shown in Figure 1.[5]

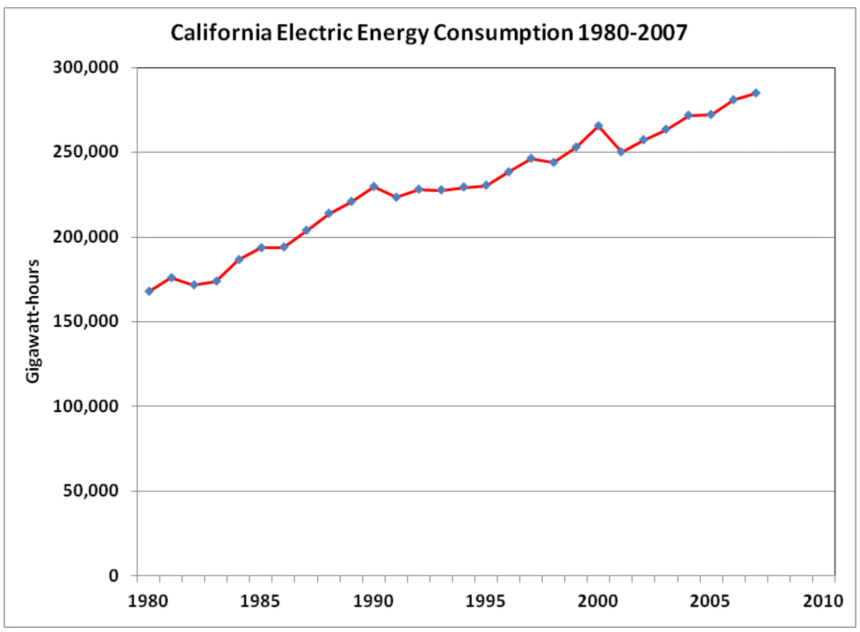

Figure 1 – Historical Electric Energy Consumption in California 1980-

The increase in the use of electricity is highly correlated to the increase in California's population. Since 1980 the state's population has grown at a somewhat smaller average annual rate of 1.7% as shown in Figure 2.

[5] California Energy Commission, "Statewide California Energy Demand 2008-2018, Staff Revised Forecast.

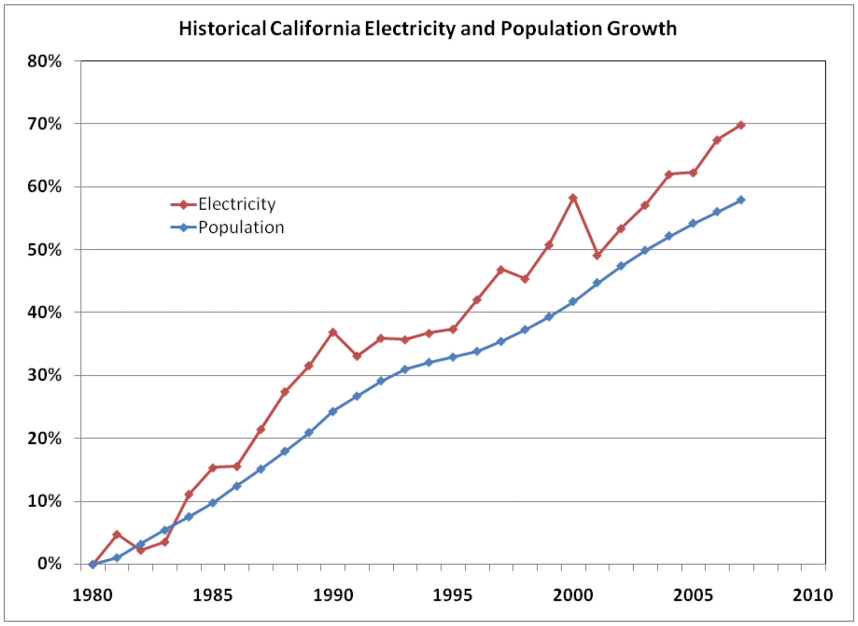

Figure 2 – Historical Electricity and Population Growth in California 1980-

The fact that California's electricity consumption and population have been growing at similar rates indicates that consumption per capita has remained approximately constant over the period, as shown in Figure 3.[6]

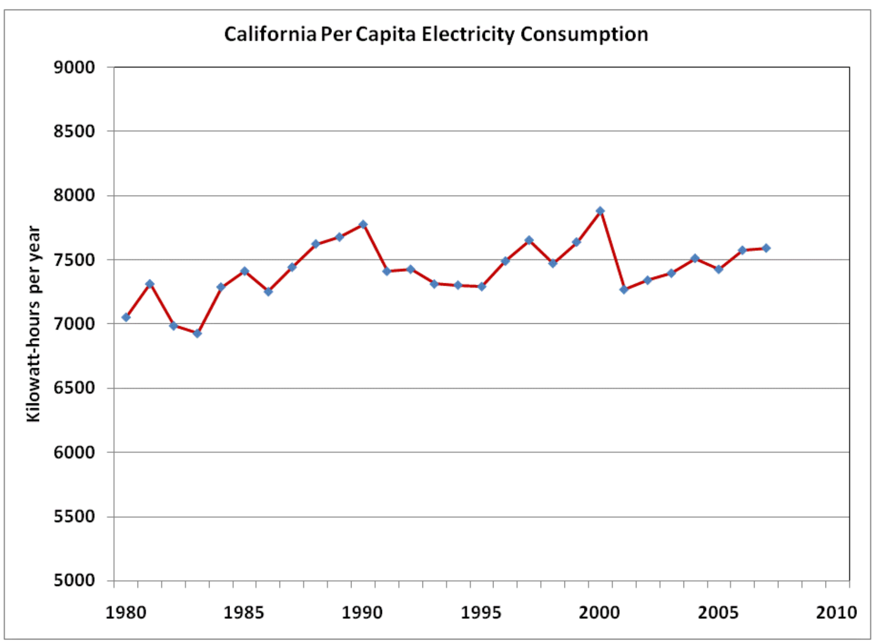

Figure 3 – Historical California Electricity Consumption Per Capita 1980-

[6] Per capita consumption represents the average individual's share of the state's total electric energy consumption, not merely consumption for which the individual is directly responsible. Per capita consumption is computed by dividing total energy use by total population.

It should be noted that during this time California has had the most aggressive building and appliance energy efficiency standards in the nation. In addition, California utilities have made substantial investments in energy efficiency programs, more than $XXX billion since 2000 alone. Recently approved programs require them to invest even more heavily over the next decade. The Loading Order in the state Energy Action Plan requires the CPUC to focus procurement of electricity on all cost-effective energy efficiency savings. Only then can it order procurement of renewables (and lastly of fossil-fired generation). These programs have helped keep per capita consumption from increasing but have not been able to reduce it.

Projecting Consumption to 2020

The question for transmission planners is what electric energy consumption will be in the future and how much of the energy supplied will require new transmission facilities. After consideration of efficiency program projections and other factors, the California Energy Commission (CEC) in its 2007 Integrated Energy Policy Report found the most probable scenario to be one in which per capita consumption continues at approximately today's level, as shown in Figure 4.[7]

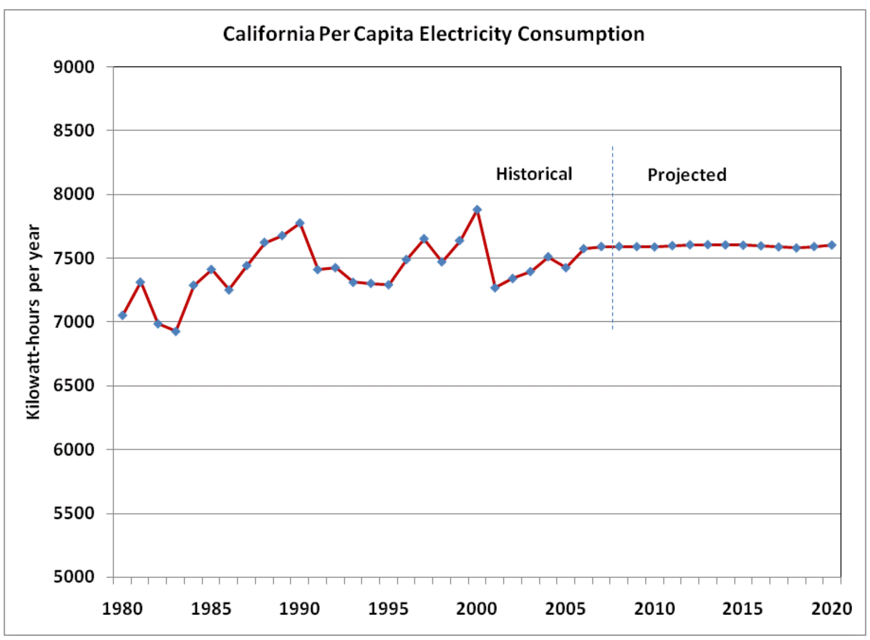

Figure 4 – Per Capita Electricity Consumption in California – Historical and Projected

[7] IEPR 2007. Note that the CEC projections reported extend only through the year 2018. Energy consumption for 2019 and 2020 has been projected at a rate of increase equal to 1.013% per year.

Combining the CEC's per capita consumption projection with the California Department of Finance (DOF) population projections[8] provides a projection of total California electric energy consumption as shown in Figure 5.[9] According to this projection, total electric energy consumption in the year 2020 would be 334,169 GWh, the value used by RETI to estimate the renewable net short.

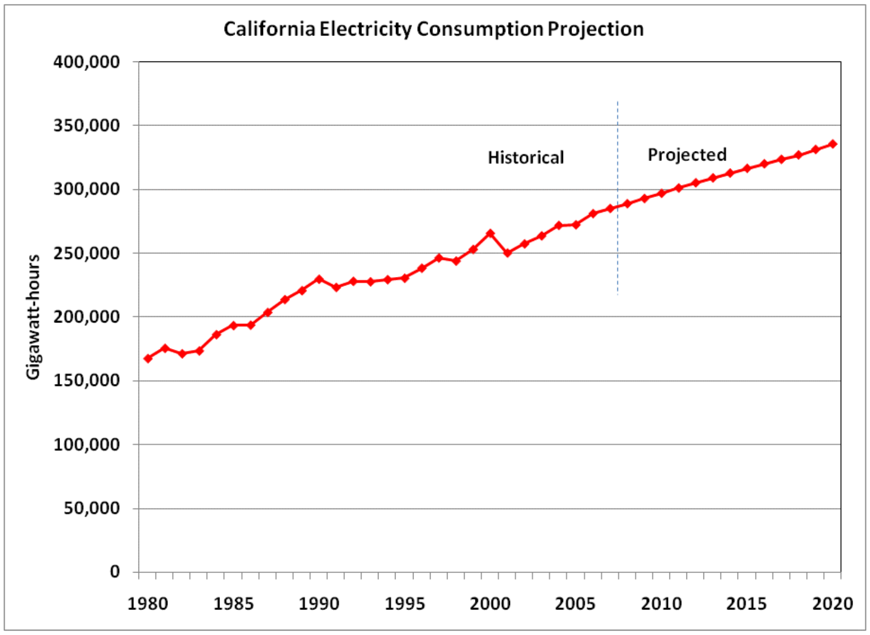

Figure 5 – Projected California Electricity Consumption 2008 – 2020

3. Accelerated Energy Efficiency Savings

An Alternative Electricity Consumption Scenario

The projected improvements in energy efficiency included in the CEC estimates do not exhaust all cost-effective possibilities, and it is possible that additional efficiency programs will be devised and implemented which would reduce consumption in 2020 below the projected value.[10] If so, the need for additional electricity and associated transmission facilities would also be reduced.

To explore this possibility, it is instructive to examine a scenario which assumes additional aggressive efficiency programs are implemented sufficient to keep total consumption from increasing over 2007 levels. Projected total consumption in such a scenario is shown in Figure 6.

[8] DOF population projections
[9] IEPR reference.
[10] Reference IEPR alternate EE scenarios.

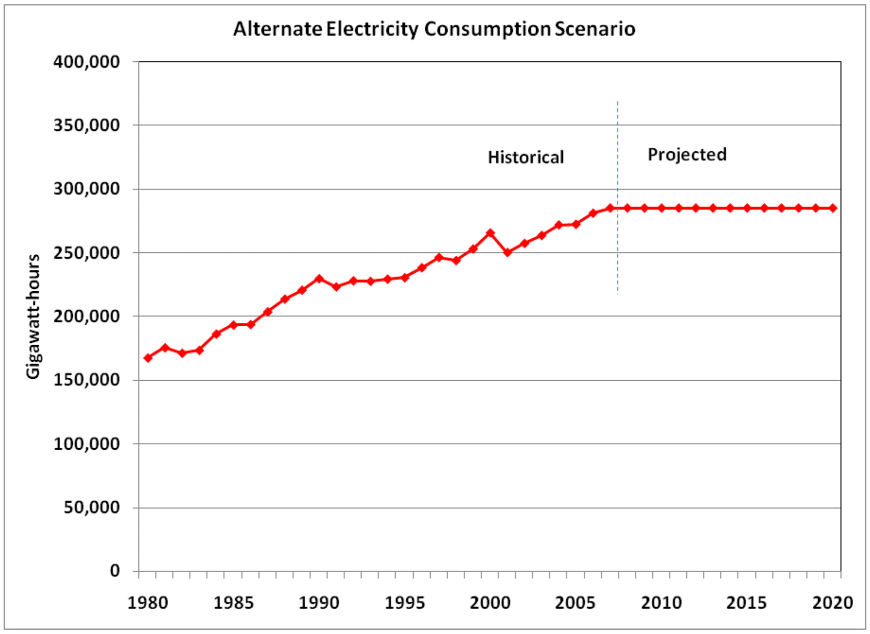

Figure 6 – Alternate Electricity Scenario with Constant Future Consumption

Since California population is projected to continue increasing between now and the year 2020, per capita consumption must decrease if total consumption is to remain constant. According to DOF, the state's population in 2020 is expected to be 17.5% larger than in 2007. This scenario thus requires per capita consumption to decrease by 17.5% as shown in Figure 7.

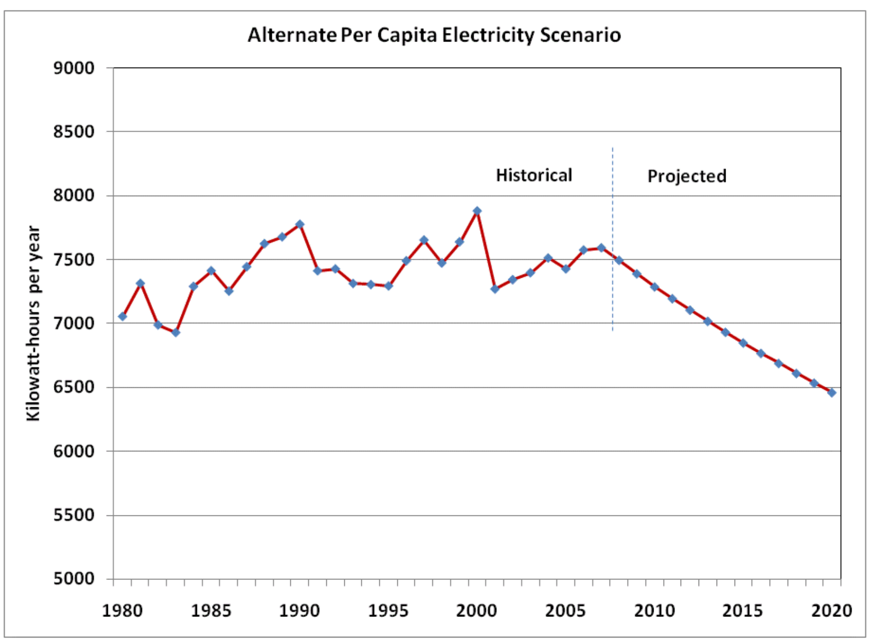

Figure 7 – Per Capita Electricity Consumption in Alternate Scenario

The decline in per capita consumption required to keep total consumption from increasing would be unprecedented in California history, as Figure 6 shows, and would have to begin immediately. Moreover, any increase in the use of electricity in some sectors—such as transportation[11]—would require further reductions in current uses.

California electricity consumption in 2007 was estimated to be 285,197 GWh and is projected to increase by 50,448 GWh by 2020. Avoiding this growth in consumption would reduce the renewable energy required to meet the state's goals by 16,161 GWh.[12]

A scenario in which total electricity consumption remains at current levels is not impossible. However, there is currently no plan to implement the aggressive reductions in per capita consumption that this scenario would require. In the absence of such a plan and a feasible implementation program, the question for policymakers is whether energy and transmission planning should be based on the expectation that such a scenario will be timely realized.

4. Accelerated Deployment of Distributed Photovoltaic (PV) Generation

As discussed above, total energy consumption will depend on the aggressiveness and success of energy efficiency programs. How much of total consumption requires new remote renewable generation and associated transmission (the renewable net short) also depends on how much renewable generation is developed locally and connected directly to the state's electric distribution system.

The technology most likely to be able to provide significant amounts of local, distributed generation is photovoltaic (PV) generation. PV systems can be installed in sizes ranging from a few kilowatts (kW) to a few megawatts (MW) on urban rooftops or structures over parking areas, for example. Somewhat larger PV systems of tens of MW might be able to be installed in larger vacant urban areas.

Historically, California has had several programs to provide incentives for installation of relatively small PV systems. In 2007 the state launched the Go Solar California program to continue provision of such incentives with a goal of 3,000 MW installed by the year 2016.[13] Most of these systems will be customer-owned and the energy generated will be used directly by the customer, thereby reducing the amount of energy sold by the utility or other LSE.

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[11] Bonds to construct an electrified intrastate high speed rail system were approved by the electorate in November 2008. In addition, the use of electricity for private vehicles such as plug-in hybrids is also being considered.

[12] $33\% \times (334{,}169 - 285{,}197) = 33\% \times 48{,}972 = 16{,}161$.

[13] The best-known component of the Go Solar California program is the California Solar Initiative (CSI) which is managed by the investor-owned utilities and overseen by the California Public Utilities Commission (CPUC) and has a goal of 1,940 MW by 2016. The other components are the New Solar Homes Partnership (360 MW); and Publicly-Owned Utilities programs (700 MW).

For purposes of this discussion, all distributed PV systems installed in the 2020 time frame are assumed to be customer-owned, with the energy used by the customer (self-generation) rather sold to other customers by the LSE.

Total Electric Energy Consumption vs Retail Sales – the Role of PV

LSE sales represent a somewhat smaller amount of energy than total consumption. Total consumption includes electric energy sold at wholesale for water pumping which is not subject to the RPS requirement. In addition, total consumption includes energy generated by consumers for their own consumption (self-generation) which is also not subject to RPS requirements.

Self-generation by PV systems reduces the amount of electricity sold by LSEs and thereby reduces the renewable net short *indirectly*. However, since self-generation by any technology does not count toward LSE RPS requirements, PV installations do not *directly* reduce the renewable net short.

CEC projections for total consumption and retail sales are shown in Table 1.

Table 1. CEC Forecast of Total Consumption and Retail Sales (GWh)*

	2010	2012	2014	2016	2018	2020†
Total Consumption	297,477	305,337	312,529	319,446	325,970	334,169
Wholesale Sales	12,295	12,298	12,298	12,299	12,299	12,299
Non-PV Self-Gen	11,520	11,723	11,926	12,129	12,333	12,262
New PV Self-Gen	361	541	721	901	1,082	1,262
Retail Sales (RPS)	273,302	280,776	287,583	294,117	300,257	308,070

*Numbers may not add exactly due to independent rounding.
†CEC estimate, private communication. The RETI Phase 1B Final Report states 2020 total consumption as 335,644.

As shown in the table, the CEC projects that by the year 2020, 1,262 GWh will be generated by new PV installations. This corresponds to about 670 MW of installed capacity at a capacity factor of 20%.[14] This projection is considerably less than the Go Solar California goal of 3,000 MW by 2016, which, if installations were to continue at the same pace through 2020, would reach 4,200 MW of new PV self-generating capacity and provide 7,358 GWh of energy.[15]

Assuming that the Go Solar California goals will be met and installations will continue at a similar pace through 2020, LSE sales in 2020 therefore would be reduced by 7,358 GWh, rather than by the 1,262 GWh projected by the CEC. As

[14] Converting from energy (GWh) to capacity (MW) requires knowing the "capacity factor" of the technology, as defined in the equation Energy (GWh) = Capacity (MW) × Capacity Factor × 8760 (hours/year) ÷ 1000 (MW/GW)

[15] RETI has revised the projection of photovoltaic installations to 2020 used in its Phase 1B Final Report. See RETI Phase 1B Final Report Update, February 24, 2009, posted on the RETI website.

described in the RETI Phase 1B Final Report Update (posted February 24, 2009), RETI uses the larger estimate of energy from new PV installations in 2020 to compute the revised renewable net short.

It must be noted, however, that since self-generation is not counted toward RPS compliance under current rules, increasing the amount of self-generated PV energy reduces the renewable net short required to meet RPS goals by only 33% as much. The dependence of the renewable net short on PV generation is shown in Figure 8. The current best estimate of the renewable net short is about 59,700 GWh in 2020.

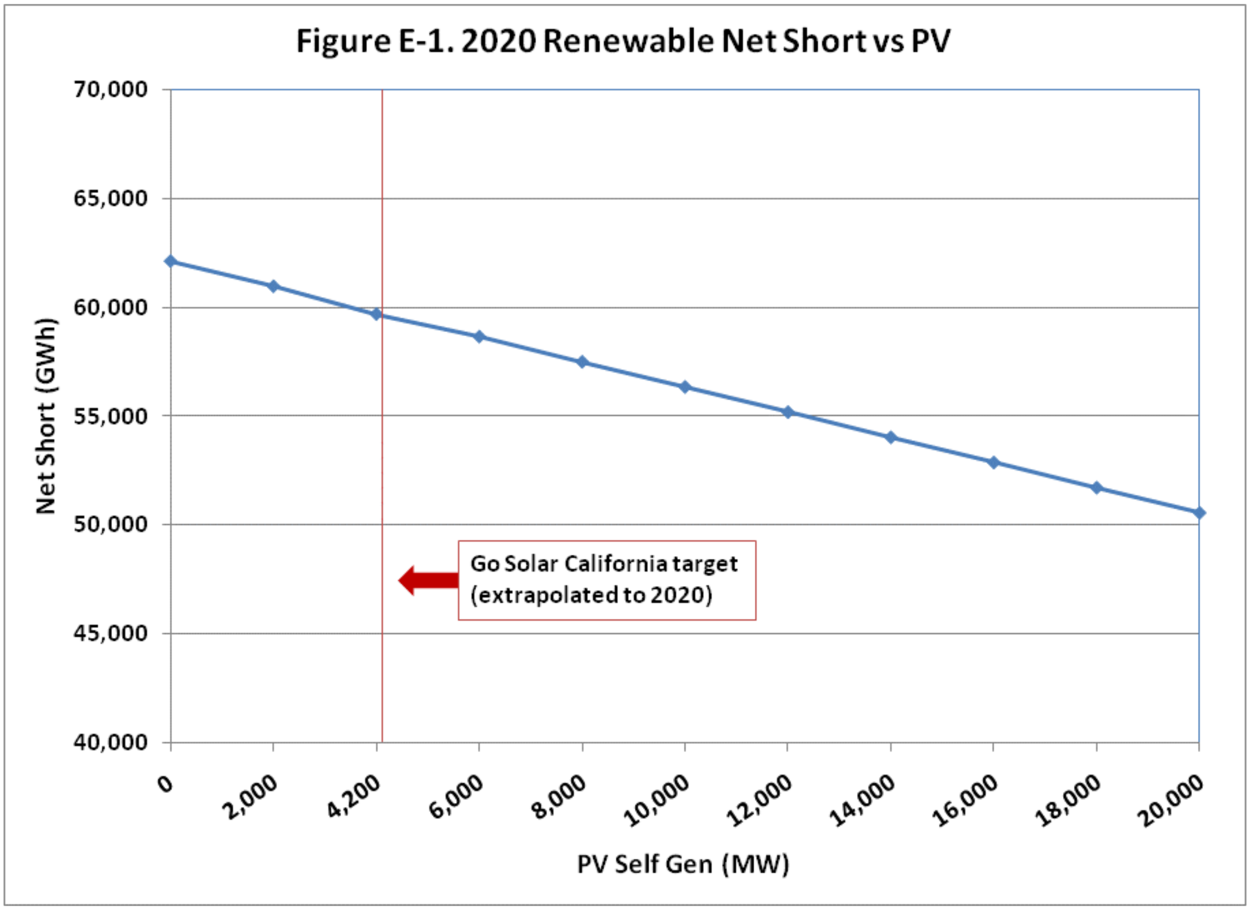

Figure 8 – The Effect of PV Self-Generation Capacity on the Renewable Net Short

Assessing Scenarios with Large-Scale Deployment of Distributed PV

Several parties commenting on the draft Phase 1B report suggested that RETI should assume sufficient PV generation will be deployed in urban areas by 2020 to substantially reduce or even obviate the need for development of remote resources and associated transmission. Because PV generation is available 5-10 hours/day, depending on season and location, significant other generation would be required in such a scenario to ensure that the supply of and demand for electricity can be balanced in every hour. This is nonetheless an attractive scenario.

The difficult questions for state regulators, utilities and transmission planners are how to assess the likelihood that this scenario will materialize; and where such solar generation will be located. The largest uncertainties concern the policy support necessary to drive such deployment; scale-up of manufacturing capacity; and cost. These are discussed below.

US installations of PV have increased markedly in the last decade as shown in Figure 9~~Figure 9~~~~Figure 9~~.[16]

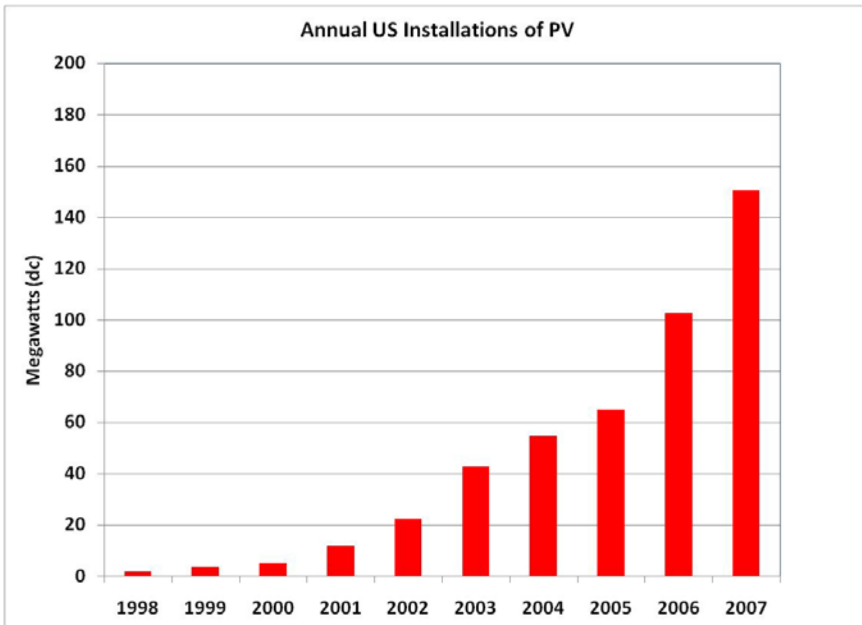

Figure 9 – Annual US Grid-Connected PV Installations

The Go Solar California program is projected to add 3,000 MW of grid-connected PV capacity by 2016. This target requires California to add six times as much PV in the next eight years as it has in the past eight years. On top of this, RETI assumes that installations will continue at that same rate, with a total of 4,200 MW installed by 2020. As of 2007, only about 500 MW had been installed in previous years.[17] In other words, RETI assumes that PV installations will increase by 840% between 2008 and 2020. This optimism is not shared by the CEC and some other observers.

Although RETI believes that it is reasonable for conceptual transmission planning to proceed on the basis that the goals of the Go Solar California program will be met, it is at least theoretically possible that distributed PV installations could increase even more rapidly and reduce the renewable net short further as shown in

[16] "US Solar Market Trends 2007", Larry Sherwood, Interstate Renewable Energy Council, August 2008. Chart data from Figure 1.

[17] This rough estimate is based on the assumption that 2/3 of US PV installations are in California.

Figure 8 above. The factors likely to influence the pace of PV installation are discussed below.`

Accelerated PV Deployment Considerations

The rapid increase in PV deployment to date has depended and will continue to depend heavily on state and federal subsidies. The pace of deployment is likely also to depend on the price of carbon emissions applied to the electricity sector in global warming reduction strategies, and incentive tariffs for locally generated solar electricity. The health of the national economy will also play a crucial role.

a) **Subsidies**. In the past, PV installations have been subsidized by a variety of programs. Go Solar California program subsidies are designed to decline over time and be eliminated by 2016. The assumption underlying the GSC program is that the subsidies will increase installations and thereby manufacturing experience, which will in turn lower costs to a level at which PV generation is competitive with other sources of electricity on a time of use basis. In 2008, Congress extended the 30% federal solar investment tax credit for eight years, to 2016, and made it available to utilities, thus opening the way to utility company ownership of relatively large-scale urban PV installations. This is expected to further bolster installation of PV (and other solar equipment).

The GSC program is perhaps the most ambitious PV subsidy program in the U.S., and should support continued rapid growth of PV deployment in California. But if the federal investment tax credit is not extended beyond 2016 and if California PV subsidies decline through 2016 and are absent thereafter, it may be difficult for 4,200 MW to be installed by 2020. Component cost, module supply and the problems associated with rooftop installations make it uncertain whether even the PV capacity goals of the GSC program will be met. However, if subsidy programs increase over current expectations, PV installations could exceed current targets.

b) **Feed-in Tariffs**. Feed-In Tariffs (FITs) require LSEs to purchase all electricity offered by eligible generators (PV in this case), and to pay a set rate for that power. They are similar to the California Standard Offer contracts that stimulated renewable energy development in the state in the early 1980s. In Germany, where payment for PV generation has been at above-market rates, FITs have driven rapid growth in PV installations.

In California, the CPUC has approved FITs for installations up to 1 MW and is actively considering, in one of its RPS proceedings, an expanded FIT program. In its 2008 Integrated Energy Policy Report Update, the California Energy Commission recommended that the Public Utilities Commission implement a system of feed-in tariffs for projects up to 20 MW.

Legislation introduced in the California Senate would create a Feed-in Tariff program in statute.[18] The proposed legislation would also set payment at the Market Price Referent, a proxy measure for the cost of non-renewable energy, but allow the CPUC to adjust the payment rate to reflect the value of electricity generated on a

[18] Senate Bill 32, introduced by Senator Negrete McLeod, December 2, 2008.

time of delivery basis. The proposed legislation would, however, cap the cumulative generating capacity able to receive the FIT rate at 500 MW. Such a program does not appear likely to be sufficient to drive PV installation beyond the GSC target, and legislation establishing larger goals may be necessary to support increased deployment beyond current targets.

c) Manufacturing and Installation Cost. There are encouraging signs that the cost of PV installations will continue to decline, perhaps substantially. "Thin film" PV collectors are less expensive to manufacture than conventional crystalline silicon modules. Given sufficient sales volume, economies of scale in thin film (and other PV technology) manufacturing could reduce the cost of PV installation and energy generated, perhaps to levels comparable to current energy prices.

Thin film PV is less efficient than crystalline silicon PV and therefore requires substantially more collector area (i.e., many more commercial or residential rooftops or ground area) to generate comparable amounts of electric energy.

An alternative scenario considered by RETI assumed that medium-sized thin film PV installations of about 20 MW may be located close to urban areas and require no significant new transmission facilities. Each such installation would require approximately 200 acres of land. To meet the renewable net short, more than 1,000 of such installations would be required, occupying approximately 200,000 acres of land. State agencies and utility companies are now evaluating availability of land near existing substations to accommodate such installations, and the electrical capacity of those substations. This will help determine the feasibility of such a development approach.

Installed costs of rooftop PV systems have significant economies of scale. According to a study of PV system costs over the period 1998-2007, systems completed in 2006 or 2007 that were less than 2 kW in size averaged $9.00/Watt, while systems larger than 750 kW averaged $6.80/Watt.[19] PV installed in residential new construction is significantly less expensive relative to retrofit installations. Widespread expansion of distributed PV beyond current programs, however, will require a large number of retrofit installations. Meeting the renewable net short in 2020 with a combination of residential and commercial rooftop PV installations would require covering the roofs of a very large majority of the buildings in the state with PV.[20] No matter how it is installed, relying heavily on PV greatly increases the total cost of meeting state renewable energy and GHG targets, as illustrated in Tables 2 and 3 below.

d) Manufacturing Scale-Up. Worldwide shipments of thin film PV collectors totaled about 500 MW in 2008.[21] Meeting Go Solar California goals (3000 MW in the

[19] Wiser, R., G. Barbose and C. Peterman, "Tracking the Sun: The Installed Cost of Photovoltaics in the U.S. from 1998-2007," Lawrence Berkeley National Laboratory, February 19, 2009. The report may be downloaded from http://eetd.lbl.gov/ea/emp/re-pubs.html.

[20] For example, a 2 kW PV system generates 0.0035 GWh/yr, and a 100 kW system generates 0.175 GWh/yr. If 50% of the state renewable requirement in 2020 were met with 2 kW residential PV systems, and 50% were met with 100 kW installations on commercial buildings, this would require 8.6 million residential installations and 170,000 commercial installations. There are approximately 11 million households in California, many of which are not single-family.

[21] RETI Phase 1B Final Report, January 2009, p. 5-31.

year 2016) with thin film PV thus requires six times total 2008 *worldwide* manufacturing capacity. Meeting an even larger percentage of RPS goals with PV would require module production on a correspondingly much larger scale.[22] A central question is how quickly worldwide manufacturing capacity, and the supply chain it depends on, can ramp up to such a huge increase in volume. Current economic conditions are likely to complicate this task.

PV manufacturing technologies are immature relative to those of other renewable generating sources. They can be expected to continue to develop for some time, as PV generating technologies themselves continue to evolve rapidly. Raw material supply required for PV manufacturing matches current demand and will have to increase proportionally to support expanded manufacturing.

Rapid addition to PV manufacturing plant and equipment depends on availability of financing; and on consistently increasing customer demand. Such demand in turn requires consistent policy support. Current economic conditions complicate the assessment of all of these components affecting the speed of manufacturing scale-up.

For the last decade, PV demand in the US has lagged that in many other countries. Worldwide demand is expected to continue to increase, along with demand from other US states. The competition for limited supply of PV modules may affect the cost and feasibility of meeting California renewable energy goals with more PV than now forecast.

5. Relative Costs of Remote Vs. Distributed Renewables

Meeting a 33% RPS (~60,000 GWh/yr Net Short) with a mix of large-scale projects would require about 15,000 MW of new biomass, geothermal, solar and wind generating capacity. Meeting a 33% RPS with PV projects would require more than double that amount of generating capacity, or about 34,000 MW of new PV installations, because PV generates electricity about 20% of the hours in the year on average. Table 2 presents the capacity factors and an illustrative mix of generation technologies.

Table 2. Capacity Required to Supply 33% Renewables:
Large-Scale Generation vs. Distributed PV
Cost and Generation Values from RETI Phase 1B Final Report

Amount of Generation Needed for 33% RPS					
	Capacity	--- to meet Net Short ---			Wghtd Avg.
Portfolio:	Factor	MW	MWh/yr	% of MW	Capty Factor

[22] The RETI Phase 1B Final Report found (p. 5-31) that 30,000 MW of thin film PV would meet nearly 80 percent of the California RPS. This would require 60 times more thin film manufacturing capacity than now exists.

Wind	35%	6,000	18,396,000	40.0%	14.0%
Geothermal	85%	2,000	14,892,000	13.3%	11.3%
Biomass	85%	500	3,723,000	3.3%	2.8%
Solar thermal	40%	6,500	22,776,000	43.3%	17.3%
w/storage		15,000	59,787,000	100%	45.5%[23]
PV-Only:					
Distributed PV	20%	34,125	59,787,000	100%	20.0%[24]

The additional capacity shown on Table 2 to be required to meet state goals with PV greatly increases the cost of the renewable energy supply, as outlined below and on Table 3.

Using the capital costs for each generating technology developed by stakeholder consensus in the RETI Phase 1B Final Report, the weighted average cost of the large-scale projects is about $3,800/kW. The cost of installing 15,000 MW of geothermal, biomass, wind and solar projects would thus be roughly $57 billion.

Black & Veatch found forecasts of crystalline silicon PV costs to be $7,000/kW in the year 2016. Black & Veatch also performed a sensitivity analysis in the RETI Phase 1B Final Report using projected thin film costs of $3,700/kW, with the caution that such a cost has not yet been demonstrated. The Lawrence Berkeley National Laboratory Study referenced above found that PV installed costs had declined from 1998 to 2007 at 3.5% per year in real dollars (although costs remained flat during the last two years of this period).[25] Using the assumption that costs will continue to decline at this rate would bring PV installed cost from $7,600/kW in 2007 to $5,715/kW in 2016 and about $5,000/kW in 2020. This would increase the cost of meeting a 33% RPS with distributed PV to more than $170 billion, or three times the cost of meeting the RPS with a mix of large-scale projects. These illustrative results are presented in Table 3.

Table 3. Cost of Generation Needed for 33% RPS ($000s)

Portfolio:	Capital cost, $/kW	% of MW	Weighted Avg. Cost, $/kW
Wind	$2,000	40%	$800
Geothermal	$5,250	13%	$700
Biomass	$4,000	3%	$133
Solar thermal	$5,000	43%	$2,167
w/storage		100%	$3,800

[23] To generate 59,787 GWh/yr requires 15,000 MW x 8,760 hrs/yr x 45.5% (the weighted average capacity factor of this illustrative portfolio of technologies).

[24] To generate 59,787 GWh/yr with PV requires 34,125 MW x 8,760 hrs/yr x 20% capacity factor.

[25] Wiser et. al., “Tracking the Sun: The Installed Cost of Photovoltaics in the U.S. from 1998-2007.”

Cost of Portfolio (000s): 15,000 MW x $3,800/kW =			$57,000,000
			Weighted Avg.
PV-Only:	Capital cost, $/kW	% of MW	Cost, $/kW
Distributed PV	$5,000	100%	$5,000
Cost of PV-only ($000s): 34,125 MW x $5,000/kW =			$170,625,000
Multiple of PV-only RPS to Portfolio of Renewables			3.0

An example can help illustrate the practical effects of the different costs shown on Table 3 for the amount of energy delivered per dollar invested for distributed PV, which has no transmission cost, compared to large-scale, remote renewables. In its January 2009 lawsuit seeking to overturn CPUC approval of the Sunrise Powerlink transmission project planned to bring power from the Imperial Valley to San Diego, the Center for Biological Diversity (CBD) proposes that the $1.9 billion cost of the transmission project instead be used to install rooftop photovoltaic systems in the San Diego area.

At a 2009 installed cost of $7,000/kW for distributed PV, $1.9 billion could provide 271 MW of generation. At a 20% capacity factor, the resulting distributed PV systems would supply 474,792 MWh of renewable electricity.[26] If used for the transmission project to deliver 1,000 MW of geothermal power from the Imperial Valley, the same $1.9 billion of ratepayer funding would provide access to 7,884,000 MWh of renewable electricity, or 16.6 times as much. If the $1.9 billion were used to pay for the combined cost of geothermal power and the transmission to deliver it, that money would buy 12,418,000 MWh, or 26 times as much as the PV systems.[27] Stated differently, it would take 26 years for the $1.9 billion of distributed PV systems to deliver as much renewable energy as the transmission project does in one year, at the same average cost.[28]

Whether or not the people of the state can collectively afford to meet RPS requirements solely with distributed PV (total cost $170 billion), when compared with a portfolio of remote renewables ($57 billion) is of course a major consideration. But timing may be an even more important one. Because CO_2 molecules remain in the

[26] 271 MW x 8,760 hrs/yr x 20% capacity factor ÷ 1,000 MWh/GWh = 474.8 GWh

[27] The transmission line would carry 1,000 MW of power x 8,760 hrs/yr, or 8,760,000 MWh/yr. The annual cost of the $1.9 billion transmission line, at a fixed charge rate of 10.4%, would be $197 million/yr. The transmission cost component of power delivered over the line would thus be $197,000,000÷8,760,000 MWh/yr = $22.6/MWh (or 2.26¢/kWh). If the geothermal generation cost $130/MWh, the combined cost of the generation and transmission would be $152.6/MWh. At that cost, $1.9 billion would buy 12,450,000 MWh of power delivered to San Diego. This is 26 times the 474,792 MWh generated by $1.9 billion of distributed PV.

[28] Over 26 years, the 271 MW of PV would eventually generate (26 years x 474,792 MWh/yr) = 12,450,000 MWh. $1,900,000,000 PV cost ÷ 12,450,000 MWh cumulative generation = $152.60/MWh, the same average cost per MWh as the remote geothermal power plus transmission.

atmosphere more than 100 years on average, emissions reduced or avoided today have much greater effect in stabilizing CO_2 concentrations than reductions achieved later. From this perspective, investments in low-carbon generation that can buy large reductions quickly appear strategic, and correspondingly valuable.

6. Ensuring Ability to Meet State Goals

Achieving 100% of the energy savings goals of the efficiency programs now forecast to be designed and implemented, and 100% of the PV self-generation forecast to be installed as a result of existing incentive programs will require both significant capital investment and continuous program adjustment and support. After assuming that these ambitious goals will be met, the state will still need 59,700 GWh of new renewable energy in 2020. The question for policymakers and the public is what kind of planning the state should undertake to ensure that this target can be met.

Transmission facilities require an average of seven-ten years to plan, permit, engineer and construct. Transmission projects being planned today will be unlikely to be placed in service before 2015. Planning for transmission necessary to deliver renewable energy by 2020 will have to be completed in the next few years.

Deferring transmission planning in favor of heavy reliance on deployment of distributed PV generation thus runs the risk that the state would not be able to meet its renewable energy and GHG goals if PV manufacturing and installation proves unable to scale up as rapidly as required.

RPS planning and procurement must target a rate of PV deployment able to be achieved despite uncertainties surrounding the consistency, duration and magnitude of policy support for exponential increases in PV deployment; technology evolution and cost decreases; and manufacturing capacity expansion.

The RETI Stakeholder Steering Committee (SSC) recognizes the uncertainty in the estimate of the renewable net short and recommends that it be updated periodically in the future as further information becomes available. At the present time, however, RETI stakeholders conclude that the calculated net short, based on CEC estimates of energy efficiency improvements and Go Solar California goals, represents a reasonable basis for conceptual transmission planning. RETI will continue to monitor the renewable net short and associated transmission requirements in the future. RETI conceptual transmission plans also will prudently allow for future upward adjustments in the net short by identifying substantially more transmission capacity that is likely to be required to meet the current estimate of the net short.

Appendix: Calculating the Renewable Net Short

In February 2009, RETI revised the calculation of the amount of new renewable energy the state will need in 2020 that was presented in the RETI Phase 1B Final Report. This revision uses a lower estimate of LSE sales, and higher estimates of PV self-generation than were used in that report. This revision of the Renewable Net Short is outlined below and explained in greater detail in the RETI Phase 1B Final Report Update posted on the RETI website.

The CEC projects that total consumption of electric energy in 2020 will be 334,169 GWh. Wholesale sales of electricity (principally for state water-pumping) and large-scale self-generation (for example, by oil refinery cogeneration units) are not subject to RPS requirements. Taking these into account, and assuming that 4,200 MW of new PV is installed by 2020 and will generate 7,358 GWh, RETI estimates LSE sales to be 301,974 GWh in that year. The 33% RPS requirement thus totals 33% of that amount, or 99,651 GWh in 2020.

Renewable energy generated from existing facilities and new facilities now under construction is estimated to be 36,807 GWh.[29] An assortment of new renewable generation technologies—wave and ocean current generation, for example—are estimated to come on line by 2020 and supply and additional 3,134 GWh annually. Since some of these technologies have not been proven commercially, this estimate may be overly optimistic but nevertheless has been assumed available. The renewable net short is the total amount of renewable generation needed in 2020, 99,651 GWh, less the amount of renewables now in operation, 36,807 GWh, less other renewables projected to be in operation by 2020, 3,134 GWh. This total is 59,710 GWh, as shown in Table 4 below:

Table 4. Electricity Supplies in 2020 to Meet 33% Goal (GWh)

Total Consum.	Wholes. (non-RPS)	Self-Gen (non-PV)	Self-Gen (PV)	LSE Sales	Existing Renew.	Misc. Other Renew.	Renew. Net Short
1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
334,169	12,299	12,538	7,358	**301,974**	36,807	3,134	**59,710**

Notes –
Column 1 – Revised total California electric energy end use consumption.

[29] Sources of qualified renewable energy technologies assumed to contribute to California energy supplies by 2020 are described in the Phase 1B report, Section 3.8.3.

Column 2 – Wholesale pumping loads not subject to RPS.
Column 3 – Self-generation other than PV and not subject to RPS.
Column 4 – PV self-generation not subject to RPS – 4,200 MW @ 20% capacity factor.
Column 5 = Col.#1 – (Col.#2 + Col.#3 + Col.#4)
Column 6 – energy from renewable projects planned and under construction as of 2008.
Column 8 = 33% × (Col.#5 – Col.# 6 – Col.#7)