DOCKETED

Docket Number:	09-AFC-07C
Project Title:	Palen Solar Power Project - Compliance
TN #:	202556
Document Title:	Exh. 3125. NGEJ . Feds bet on wrong solar
Description:	NGEJ. Federal gov't bets on wrong solar horse
Filer:	Ileene Anderson
Organization:	Center for Biological Diversity
Submitter Role:	Intervenor
Submission Date:	6/23/2014 4:30:48 PM
Docketed Date:	6/23/2014

Federal Government Betting on the Wrong Solar Horse

Bill Powers

The United States is wasting billions of dollars of American Recovery and Reinvestment Act (ARRA) cash grants and loan guarantees on very large, high-cost, high-environmental-impact, transmission-dependent desert solar thermal power plants that will be obsolete before they generate a single kilowatt-hour of electricity.

The United States is wasting billions of dollars . . . on very large, high-cost, high-environmental-impact, transmission-dependent desert solar thermal power plants that will be obsolete before they generate a single kilowatt-hour.

A solar strategy that would have been state-of-the-art in the 1990s, prior to the advent of low-cost solar photovoltaic (PV) power, is now being executed. This is a victory for the broad government, utility, and environmental organization support that solar thermal technology has gained over the last few decades. It is also a victory for the lobbying power of this coalition over economic common sense. Solar thermal has lost the cost-effectiveness race to solar PV. The federal government has not yet absorbed the significance of this important development.

The Department of Energy (DOE) is in the process of completing a potentially landmark study, the Solar Vision Study (SVS). It maps out a strategy to provide the United States with 10 to 20 percent of its electric energy from solar power by 2030. The document appears to be intended to serve as technical support for a national strategic commitment to solar thermal development.

However, the draft SVS, while containing much useful information, is flawed. The SVS proposes that half of the nation's solar power will come from solar thermal installations, based on a low and unsupported cost-of-energy forecast for solar thermal plants. The SVS also presumes that the Southwest will be the hub from which this solar power is generated and transmitted to other parts of the country, while estimating an almost trivial transmission expense to make this happen.

SVS proposes that half of the nation's solar power will come from solar thermal installations, based on a low and unsupported cost-of-energy forecast for solar thermal plants.

Bias in the current administration's ill-conceived use of limited ARRA funds to subsidize obsolete solar thermal technologies may explain why the draft SVS does not evaluate solar thermal technology with a neutral and critical technical eye. A revised and corrected SVS would envision a solar future that is effectively 100 percent solar PV. This PV future would also be predominantly smaller-scale PV connected at the distribution level, to avoid the expense of transmission. Otherwise, enormous costs for the new transmission capacity would be necessary to move remote Southwest solar power to demand centers around the country. The future is distributed PV if the strategic objective is the least-cost solar energy generated and delivered

Bill Powers, P.E. (bpowers@powersengineering.com), is president of Powers Engineering.

DOI 10.1002/gas / © 2010 Wiley Periodicals, Inc.

to the end-user. The Germans, Chinese, Taiwanese, and Japanese seem to understand this. It has not yet sunk in at the highest levels of the US government.

OUTMODED SOLAR THERMAL GIVES SOMETHING FOR EVERYBODY—AT TAXPAYER EXPENSE

In the late 1970s and early 1980s, relatively high levels of funding were made available via DOE to develop a variety of solar thermal technologies, including parabolic solar trough, power tower, and solar dish (Stirling) engine. Demonstration projects were built and operated. Parabolic solar trough and power towers concentrate solar energy on a working fluid, heat it to a high temperature, and transfer that heat to water to generate stream. This steam is then run through a conventional steam turbine generator to produce electric power. Solar dish engines focus solar energy on an engine that uses hydrogen as the working fluid. The engine drives a small electric generator.

During the Reagan years, federal funding for solar thermal was substantially reduced.

Between 1985 and 1991, ultimately 354 megawatts of parabolic solar trough power plants were constructed in the Mojave Desert. These plants were financed with standard-offer, "must-take" utility contracts. Parabolic solar trough plants are the one form of solar thermal technology that has an extensive track record in commercial operation. The term "solar thermal" generally refers to parabolic solar trough plants unless additional clarifying information is provided.

Solar thermal demonstration projects . . . in the 1980s established a constituency of solar thermal supporters—DOE, research laboratories contracting with DOE, aspiring solar thermal project developers, and major environmental organizations concerned about climate change.

California's renewable portfolio standard (RPS) legislation, initially signed into law in 2002, gave new impetus to building solar thermal plants. The state's greenhouse gas reduction legislation promulgated in 2006, targeting an 80 percent reduction in greenhouse gas emissions be 2050, provided further support. However, since 1991, other than one 64-megawatt solar thermal plant built in the Nevada desert in 2007 (Nevada Solar One) and two 5-megawatt demonstration plants built in California in 2008 and 2009, there have been no solar thermal plants built in the United States.

Development of large-scale solar thermal projects in the California desert in the 1980s established a framework for solar energy development—large, remote solar thermal plants requiring transmission to reach demand centers. The government solar thermal demonstration projects and commercial solar trough projects also established a constituency of solar thermal supporters—DOE, research laboratories contracting with DOE, aspiring solar thermal project developers, and major environmental organizations concerned about climate change. The investor-owned utility lobby is also supportive of remote utility-scale solar projects to the extent they require new transmission or major transmission upgrades that can be put into the utility rate base. The substantial political clout of this combined constituency is now bearing fruit in the form of ARRA loan guarantees and cash grants preferentially being directed to solar thermal projects.

The investor-owned utility lobby is also supportive of remote utility-scale solar projects to the extent they require new transmission.

Government subsidies for solar thermal projects would not necessarily be a negative development if these technologies remained the most cost-effective solar option for generating electric power. But that day has passed. Solar thermal has lost the cost-effectiveness race to solar PV. Subsidies spent on solar thermal technologies are wasted subsidies.

SHOWING SOLAR THERMAL NO LONGER COMPETITIVE WITH SOLAR PV

CPS Energy, the San Antonio public utility, offers a case study in cost-based solar energy project selection. CPS Energy was developing a 27-megawatt Tessera Solar dish engine project in West Texas. The power-purchase agreement (PPA) between CPS Energy and

Tessera was recently cancelled due to Tessera's inability to get project financing at the agreed-upon PPA terms.[1] The cancelled Tessera project was subsequently replaced with three 10-megawatt distributed PV projects to be built around San Antonio.[2]

The PPA rate for the CPS distributed PV projects is $150 a megawatt-hour.[3] There will be no transmission cost, as these projects will be built within the San Antonio demand center itself. San Antonio has a good solar resource. However, it is 10 to 20 percent less robust on an annual basis than Southern California coastal and desert sites.[4]

What is true for San Antonio is even more so for Southern California. It has by far the most operational solar thermal capacity in the country and has been evaluating the cost of solar thermal projects in detail for years. Current cost-of-energy data developed by California energy authorities makes clear that solar thermal cost of energy is much greater than the cost of energy from the distributed PV projects being developed by CPS Energy.

The California Public Utilities Commission estimates the cost of energy from a base-case, dry-cooled solar thermal plant at a best-case Mojave Desert site in Southern California is $202 a megawatt-hour.[5] The Commission estimates a new transmission cost of $34 to $46 a megawatt-hour to move this desert solar power to load centers.[6] Transmission losses consume about 5 percent, the equivalent of $10 a megawatt-hour, of this remote solar energy production.[7] As a result, the "all-in" cost of energy for this representative solar thermal project is approximately $250 a megawatt-hour.

The "all-in" cost of energy for this representative solar thermal project is approximately $250 a megawatt-hour.

In the Mojave Desert, the solar exposure is about 20 percent better than in San Antonio, while that for Southern California demand centers Los Angeles and San Diego is about 10 percent better. If the same three 10-megawatt distributed PV projects located in San Antonio were located in or near Los Angeles or San Diego, they would produce approximately 10 percent more electricity over the course of a year for the same capital and operations and maintenance cost. This means that the PPA rate of $150 a megawatt-hour at the San Antonio solar PV site adjusts to a PPA rate of about $136 a megawatt-hour at sites in or near Los Angeles or San Diego for roughly the same return on investment.

The PPA rate . . . at the San Antonio solar PV site adjusts to a PPA rate of about $136 a megawatt-hour at sites in or near Los Angeles or San Diego.

Few consumers would doubt which solar electricity option to select if one option delivers solar electricity at $136 a megawatt-hour and the other option produces the same commodity at $250 a megawatt-hour. The proposed solar feed-in tariff for the city of Los Angeles, which would include commercial rooftop PV, ground-mounted PV, and residential PV, has a 2010 composite rate of $220 a megawatt-hour and drops rapidly in future years.[8] Even this proposed feed-in tariff is substantially less than the "all-in" cost of energy for solar thermal projects. Yet both the state of California and the U.S. government are making major strategic commitments to the highest-cost $250-a-megawatt-hour solar thermal option.

Few consumers would doubt which solar electricity option to select if one option delivers solar electricity at $136 a megawatt-hour and the other option produces the same commodity at $250 a megawatt-hour.

SOLAR THERMAL PROJECTS BUILT WITH ARRA SUBSIDIES—CASTLES IN THE SAND

Investors laud the ARRA program for eliminating the investment risk associated with solar thermal plants. However, the investment risk is there in the first place because of questions about the cost-effectiveness of the solar thermal technologies relative to the better competitor—solar PV. Without ill-conceived government intervention, the obvious risks would kill these

DOI 10.1002/gas / © 2010 Wiley Periodicals, Inc.

solar thermal projects. These technologies were cutting-edge at one time. They no longer are.

A recent story on the critical role of ARRA loan guarantees and cash grants in making these solar thermal projects possible captures the frenzy of investors to cash in on the government's largesse.

> This first wave (of solar thermal plants) may very well be the last for a long time, according to industry executives.
>
> Without continued government incentives that vastly reduce the risks to investors, solar companies planning another dozen or so plants say they may not be able to raise enough capital to proceed.
>
> "I think we're going to see a burst of projects over the next two months and then you're going to hear the sounds of silence for quite a while," said David Crane, chief executive of NRG Energy, on Wednesday after he announced that his company would invest $300 million in the Ivanpah plant.
>
> Solar developers depend on two federal programs to make their projects financially viable. The most crucial is a loan guarantee program, expiring next September, that allows them to borrow money on favorable terms to finance up to 80 percent of construction costs.
>
> The other is the option to take a 30 percent tax credit in the form of a cash payment once a project is built. Although the tax credit does not expire until the end of 2016, the option to take it as a cash payment disappears this year, making it far less valuable to a start-up company that is just beginning to generate revenue.
>
> "Without the Department of Energy coming in to assume a lot of the risk, you might not find lenders willing to lend, particularly if you're a start-up with untried technology," said Nathaniel Bullard, a solar analyst at Bloomberg New Energy Finance. (Woody, T. [2010, October 28]. Solar power projects face potential hurdles. *New York Times,* http://www.nytimes.com/2010/10/29/business/energy-environment/29solar.html).

While the federal government pours funding into solar thermal projects, the superior cost-effectiveness of solar PV over solar thermal continues to increase. A renewable energy trade publication succinctly sums up the current state of the competition between solar PV and solar thermal.

> The relentless price declines of PV panels allow developers to build PV plants at a lower cost than their CST (concentrating solar technology) cousins. This issue is illustrated in the following capital-cost-per-watt chart (an excerpt from the upcoming GTM Research CSP Report). In 2010, the price to build a CSP park run by troughs, power towers or dish engines will cost between $5.00 and $6.55 a watt.
>
> On the other hand, utility-scale PV projects can squeak through at less than $3.50 a watt (DC). By 2020, the CSP solutions are expected to be in the $2.40 to $3.80 a watt range, but by that time, PV plants could be below $2 a watt (DC). Trough and tower plants are behind PV, and not likely to catch up. (Kanellos, N., & Prior, B. [2010, October 18]. Are solar thermal power plants doomed? *GreenTech Media,* http://www.greentechmedia.com/articles/read/is-CSP-doomed/).

DOE'S STUDY IS PLAYING SOLOMON WHEN THE WINNER IS NOT IN DOUBT

DOE released the draft SVS for review in May 2010. As of November 1, 2010, the final version of the SVS had not yet been published. The two fundamental premises of the SVS are the following: (1) it is possible to meet 10 percent or 20 percent of U.S. electricity demand from solar resources by 2030 and (2) this solar energy will be provided in approximately equal proportions from utility-scale solar thermal and solar PV power plants, with utility-scale solar PV plants providing a large majority of the PV capacity. The draft SVS does not look at a scenario where a substantial amount of the solar power is generated by distributed PV.

The agency invited peer review of the draft document from professionals working in the field of solar energy. Presumably this was done to validate the data and conclusions included in the draft SVS, and to allow DOE to make necessary adjustments in the final version to assure the document gained wide acceptance as technically accurate and sufficiently substantial to serve as the basis for national policy decisions on solar energy development. However, at least as of the date of publication of this article, DOE has determined not to respond to peer review comments until after the final SVS is released.

DOE has determined not to respond to peer review comments until after the final SVS is released.

In its current form, which is a mix of accurate technical information and spectacularly optimistic solar thermal cost projections, the SVS will be of little value for policymaking. The lack of technical or cost support for building 43,000 to 63,000 megawatts of high-cost solar thermal projects by 2030, a fundamental thesis of the SVS, means the document runs the danger of being little more than a political advocacy piece for solar thermal promoters—cloaked in a DOE binder.

The lack of technical or cost support for building 43,000 to 63,000 megawatts of high-cost solar thermal projects . . . means the document runs the danger of being little more than a political advocacy piece for solar thermal promoters—cloaked in a DOE binder.

Half-Truths and Bad Information Abound

Much of the information in the draft SVS chapter on cost of solar PV is accurate and current. Selected but critical bits of information in the draft solar thermal chapter are contradictory and wrong.

For example, the SVS indicates graphically that solar thermal is substantially more cost-effective than solar PV. This was true in 1990 but false in 2010.

The report also asserts that solar thermal plants equipped with thermal storage can have capacity factors as high as 50 percent, without clearly explaining how that could be possible using the conventional definition of capacity factor. This erroneous or misleading information is used as technical support for advocating that vast economic resources be committed to building sufficient solar thermal plants to contribute half of the nation's solar electric output by 2030.

Erroneous or misleading information is used as technical support for advocating that vast economic resources be committed to building sufficient solar thermal plants to contribute half of the nation's solar electric output.

Solar Power at Night?

The capability of solar thermal plants to operate through the night if equipped with sufficient thermal storage is also put forward as a major justification. However, the SVS does not make an economic case for following this approach. Much of the electricity generated from the stored thermal energy would be produced at night during periods of low demand, when the solar thermal plant will be competing for market share with existing and much lower-cost nuclear, hydroelectric, natural gas combined-cycle, and some coal for decades to come.

In contrast, a strong economic case can be made for either solar thermal or PV plants to be equipped with limited storage to allow full capacity output during summertime peak demand periods when time-of-use power prices are high, assure reliability under all climatic conditions, and serve as nonspinning reserves. There is probably no economic case for building solar thermal plants or solar PV with more than two to three hours of storage until at least 2030. There is no economic justification now to equip a solar thermal plant so that it can convert high-value daytime peaking power into lowest-value off-peak power released between 10:00 p.m. and 6:00 a.m.

"Capacity Factor" Mysteriously Redefined

The draft SVS uses the term *capacity factor* in an unconventional manner for a solar thermal plant with thermal storage. The document

DOI 10.1002/gas / © 2010 Wiley Periodicals, Inc.

states that solar thermal plants without storage have capacity factors of 20 to 28 percent and that plants with 6 to 7.5 hours of storage have capacity factors of 30 to 50 percent. However, the high capacity factor for the solar thermal plant with storage is an artifact of what is in effect an artificial throttling of maximum output of the plant and not an almost magical increase in the ability of a solar thermal plant with storage to extract more solar energy from the sun.

Thermal storage is also expensive. The estimated average 2010 capital cost of a 200-megawatt dry-cooled solar thermal plant with six hours of thermal storage is $7,750 a kilowatt, 42 percent more than the capital cost of a solar thermal plant without storage.[9] The estimated average 2010 capital cost of a 20-megawatt fixed distributed PV array without storage is $3,800 a kilowatt.[10]

There is a nearly $4,000-a-kilowatt difference in the capital cost of these two solar options. Including lead-carbon battery storage to the PV system would add about $500 a kilowatt to the cost of the PV system.[11] This means that adding three hours of energy storage, sufficient for the PV system to act as a completely reliable peaking power system when electricity demand and power prices are high, would add around $1,500 a kilowatt to the PV system cost. The overall system cost of the PV system with three hours of storage would be $5,300 a kilowatt. This is well below the $7,750-a-kilowatt capital cost of the solar thermal plant with storage while providing economically "right-sized" energy storage capacity tailored for current and foreseeable energy market conditions.

In a plant with thermal storage, the quantity of solar troughs is oversized for the steam turbine generator such that some of the thermal energy must be transferred to storage. For example, a collector array with capacity sufficient to meet the steam requirements of a 100-megawatt steam turbine generator is instead designed and constructed with a 70-megawatt steam turbine generator, and the rest of the thermal energy is sent to storage. This is equivalent to operating a 1,000-kilowatt PV array, sending a maximum of 700 kilowatts to the grid, and diverting the remaining electric power to battery storage for later use. Storing energy for later use is not a unique characteristic of solar thermal technology.

The total amount of heat energy produced by the solar thermal plant without storage rated at 100 megawatts is the same as that produced by a solar thermal plant—with the same collector array—that is equipped with a 70-megawatt steam turbine generator and thermal storage to absorb the heat energy not immediately converted into electricity. Yet the solar thermal plant with storage is credited in the draft SVS with a capacity factor that is as much as double the capacity factor of the solar thermal plant without storage. This creates confusion and the illusion that solar thermal with storage achieves a much higher capacity factor than a plant without thermal storage.

Transmission Cost Way Off the Mark

The draft SVS projects that the total new transmission cost will be only $44 to $47 billion to develop solar resources predominantly in the Southwest to deliver 485 terawatt-hours and 824 terawatt-hours to primarily eastern load centers.[12] California is currently projecting it will spend $27.5 billion for sufficient transmission to move 24 terawatt-hours of solar generation to California load centers, and California solar resources are relatively close to these load centers. Extrapolating real California transmission cost estimates to 485 terawatt-hours of solar generation gives a projected transmission cost of (485 terawatt-hours/24 terawatt-hours) × $27.5 billion = $556 billion. Extrapolating real California transmission cost estimates to 825 terawatt-hours of solar generation gives a projected transmission cost of (824 terawatt-hours/24 terawatt-hours) × $27.5 billion = $994 billion. The SVS must be more realistic in its estimate of the cost of transmission or it will present an erroneous picture of the total cost to policymakers and the general public.

Land-Use Arguments Faulty

The SVS excuses large consumption of land for solar thermal by saying it is less than is being consumed for coal mining each year. This statement has two implications: (1) construction of solar thermal will result in a concomitant reduction, at least, of land disturbance due to coal mining and (2) solar thermal is less destructive than land disturbance caused by coal mining and therefore affected parties should accept solar thermal as an inherently better option for the general national good than coal.

There are a couple of problems with this justification. First, the SVS concedes that solar power will displace natural gas, not coal; therefore, no coal mining disturbance will be reduced because of the construction of solar thermal. Second, affected parties are by definition local and are unlikely to link the negative environmental impacts caused by solar thermal development and associated transmission lines to a lessening of environmental impacts (which the SVS indicates will not occur anyway, at least under one of its scenarios) in a distant part of the country. This lack of justification is especially true given that many of the affected parties in areas where large amounts of solar thermal are being planned are already aware that the distributed PV alternative could provide the same amount of electricity with lower overall cost and almost no environmental impact.

FALSE CLAIM—SOLAR THERMAL NECESSARY QUICKLY FOR ENVIRONMENTAL REASONS

California provides a useful case study of the urban legend that only large-scale solar plants can provide the rapid capacity build-up needed to address climate change. The California Public Utilities Commission reference case to achieve 33 percent renewable energy by 2020 includes 10,000 megawatts of new solar capacity.[13] The large majority of this capacity is assumed by the commission to consist of utility-scale desert solar thermal plants. This 10,000 megawatts of new capacity will be added over ten years, an average of 1,000 megawatts added each year. Promoters of the utility-scale desert solar thermal strategy relentlessly stress that only utility-scale solar plants can add capacity quickly enough to achieve California's ambitious renewable energy targets and effectively address climate change.

Approximately 2,800 megawatts of utility-scale solar thermal projects have been approved by the Department of Interior (DOI) as of October 2010.[14] All of these projects are in California deserts. DOI land-use authorization is a necessary step for any solar project that will be located on federal public lands under Bureau of Land Management control. Many of these projects will also receive ARRA loan guarantees and cash grants. Approximately 1,400 megawatts of this capacity consist of Tessera dish engine projects. In my opinion, despite the loan guarantees and cash grants, these dish engine projects are unlikely to be built due to the technical immaturity and relative unreliability of the technology.

About 17,000 megawatts (21,000 megawatts [DC][15]) of PV were installed worldwide by the end of 2009. In contrast, the worldwide capacity of solar thermal at the end of 2009 was 664 megawatts. Most of this solar thermal capacity was built in California in the 1980s and early 1990s.

OTHER NATIONS OPTING FOR SOLAR PV

While California and the federal government work hard to preferentially advance the cause of high-cost solar thermal, the world is building lower-cost solar PV.

Germany, which is approximately the same size as California, added about 4,000 megawatts of distributed PV in the first eight months of 2010. The vast majority of German PV is going on rooftops and parking lots. The mechanism that Germany is using for this spectacular PV installation rate is a feed-in tariff. This is a tiered rate paid by the utility to the solar developer, commercial building owner, or homeowner that provides modest profit for the solar power generated. As noted earlier, the feed-in tariff proposed for Los Angeles would produce substantially lower-cost solar electricity than the Commission's predominantly solar thermal reference case.

By the end of 2010 Germany will have added approximately 10,000 megawatts of distributed PV in the three-year period from January 2008 through December 2010. While California lumbers forward with a high-cost, controversial solar strategy built around remote utility-scale solar thermal plants, with the hope that 10,000 megawatts can be built in ten years, Germany is demonstrating now that 10,000 megawatts of distributed PV can be added in only three years. Germany has also become a world leader in solar PV development. The country generated $7.8 billion in export earnings from solar PV (€5.6 billion) in 2009.

Former Secretary of State George Shultz and former CIA Director James Woolsey are both calling for German-style feed-in tariffs to accel-

DOI 10.1002/gas / © 2010 Wiley Periodicals, Inc.

erate the use of solar power in the United States. Governor-elect Jerry Brown of California called for 12,000 megawatts of local renewable power, out of 20,000 megawatts of new renewable energy capacity, in his June 2010 Clean Energy Jobs Plan. The German feed-in tariff program is leading to fast and noncontroversial deployment of solar power.

CONCLUSIONS

The current federal government preference for solar thermal plants, which would have deservedly faded away without massive government subsidies in the form of ARRA loan guarantees and cash grants, is the wrong strategy. Solar PV is a more cost-effective solar technology, and the gap in cost-effectiveness between solar PV and solar thermal will continue to grow. DOE's draft SVS, intended to provide the technical support for an ambitious national strategy to meet up to 20 percent of the nation's electricity demand with solar power by 2030, is flawed in its treatment of solar thermal technology. An unsupported and low forecast of solar thermal cost is used in the draft SVS as a basis for advocating the construction of up to 63,000 megawatts of solar thermal capacity by 2030.

A strategy focused primarily on distributed PV would be the most cost-effective approach to rapidly expanding solar power production in the United States. Germany has demonstrated that a spectacularly high distributed PV installation rate is sustainable when an appropriate contract structure, the feed-in tariff, is utilized. Feed-in tariffs are cost-effective relative to solar thermal. The cost of solar electricity generated under a proposed feed-in tariff for Los Angeles would be significantly less than the "all-in" cost of electricity from utility-scale solar thermal projects in California's deserts.

It is time for the United States to stop wasting limited resources on obsolete solar thermal technologies and to embrace the formula for solar success pioneered by Germany.

It is time for the United States to stop wasting limited resources on obsolete solar thermal technologies and to embrace the formula for solar success pioneered by Germany.

NOTES

1. SNL Financial. (2010, September 2). Tessera Solar bows out of contract with CPS Energy on Texas project, snl.com.
2. SNL Financial Power Edition. (2010, October 7). In the news: CPS Energy to develop three 10-megawatt solar PV projects in its service area, snl.com.
3. Ibid.
4. NREL PV Watts Calculator, Version 1: http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/.
5. California Public Utilities Commission—2010 Long-Term Procurement Proceeding, Planning Standards for System Resource Plans—Part II, Long-Term Renewable Resource Planning Standards, Attachment 1, June 22, 2010, Table 1, p. 8.
6. California Public Utilities Commission. (2009, June). 33% renewable portfolio standard implementation analysis preliminary results, Table 4 and Table 5, pp. 21–22. Cost per megawatt-hour for new transmission is calculated as follows: $1.27 billion a year in new transmission expense ÷ 36.9 million megawatt-hours a year transmitted by new transmission lines = $34.45 a megawatt-hour. A 40-year transmission amortization period is used by the CPUC to calculate annual transmission expense. The CPUC uses a 20-year amortization period to calculate the annual cost of new renewable generation resources.

   An additional source is e-mail communication between CPUC contractor Arne Olson of Energy & Environmental Economics (E3) and Bill Powers, Powers Engineering, January 5, 2010. A 20-year transmission cost amortization increases the annual cost factor from 0.1246 to 0.1676, a 34.5 percent increase in the annualized cost of transmission over a 40-year amortization period. As a result, the transmission penalty must be adjusted upward by an equivalent amount. The adjusted transmission penalty is $34.45 a megawatt-hour × (1.345) = $46.34 a megawatt-hour.
7. Renewable Energy Transmission Initiative. (2010, April 8). CREZ name and number—Project characteristics and cost calculator. In-state transmission loss = 5 percent, http://www.energy.ca.gov/reti/documents/index.html.
8. UCLA and Los Angeles Business Council. (2010, July 8). *Bringing solar energy into Los Angeles: An assessment of the feasibility and impacts of an in-basin solar feed-in tariff program,* http://www.labusinesscouncil.org/online_documents/2010/Consolidated-Document-070810.pdf; Table 3, p. 32.
9. Renewable Energy Transmission Initiative (California), RETI Phase 2B Final Report, May 2010, Table 4-6, p. 4-6.
10. Ibid., Table 4-8, p. 4-7.
11. Telephone communication between Dr. Bob Nelson, Axion Power Battery Manufacturing, Inc., and Bill Powers, Powers Engineering, January 8, 2009. The Axion automated lead-carbon manufacturing line was inaugurated in early 2009. The estimated cost of production at high automated manufacturing rate is $350 to $400/kW. A more conservative estimate of $500/kW is used in this article, as it is unknown if a high automated manufacturing rate has been achieved.
12. 1 terawatt-hour = 1 million (10^6) megawatt-hours.
13. California Public Utilities Commission, 33% Renewable Portfolio Standard Implementation Analysis Preliminary Results, June 2009, p. 87.
14. DOI Bureau of Land Management. (2010, October 20). In the spotlight—solar energy California, http://www.blm.gov/ca/st/en.html.
15. DC = direct current. In this section, all current measures refer to alternating current unless otherwise specified.

