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Subject: Powers Engineering Comment Letter on Draft DRECP NEPA/CEQA

A major flaw in the draft DRECP and DEIR/EIS ("DRECP") is the failure to include a behind-the-meter local solar alternative as the "no action" alternative to the targeted renewable energy generation levels in the DRECP study area for utility-scale solar, utility DG solar, and wind power. The local solar "no action" alternative is the most likely scenario given: current behind-the-meter solar installation rates of more than 1,000 MW per year, the cost-competitiveness of behind-the-meter solar compared to utility power with or without net-metering, state law mandating that the CPUC support sustained growth of behind-the-meter solar installations through appropriate rate design after net-metering expires, and the state's ongoing commitment to smart grid modernization of the existing distribution grid to allow it to fully accept two-way power flows and eliminate distribution grid reliability issues as a brake on customer-provided local solar development. In addition, the local solar "no action" alternative would eliminate the $140 billion life-of-project cost and environmental impact of 13 to 14 new 500 kV transmission lines assumed in all DRECP scenarios.

I. Proposed 500 kV transmission build-out will add $90 per megawatt-hour to DRECP solar and wind cost of generation

The DRECP assumes a need for new transmission lines to deliver about 14,000 MW for all alternatives. This 14,000 MW would be delivered over 13 to 14 500 kV transmission lines, depending on the alternative, as shown in Table 1.

Table 1. Number of new 500 kV lines projected for each DRECP scenario[1]

Alternate 1	Alternate 2	Alternate 3	Alternate 4	Alternate 5	No Action
14	14	14	14	13	14

The DRECP also identified a representative 500 kV line, SDG&E's 500 kV Sunrise Powerlink completed in 2012, as having a capacity of 1,200 MW.[2] The 2006 application for the Sunrise Powerlink estimated an initial capital cost of $1.265 billion and a 40-year life of project cost of

[1] Draft DRECP and EIR/EIS, *Appendix K – DRECP Transmission Technical Group Report Conceptual Transmission Plan for DRECP Alternatives*, October 2013, pp. 29-33.
[2] Ibid, p. 1.

$6.96 billion in 2010 dollars.[3] The Sunrise Powerlink capital cost approved by the California Public Utilities Commission in 2008 was $1.883 billion in 2012 dollars.[4] Extrapolating from the ratio of capital cost to the 40-year life-of-project cost Sunrise Powerlink application, the approximate life-of-project cost of the Sunrise Powerlink will be $10 billion in 2012 dollars.[5]

Assuming fourteen 500 kV lines equivalent in cost to the Sunrise Powerlink are built to deliver renewable energy generated in the DRECP study area, the total 40-year life-of-project cost will be approximately: 14 x $10 billion = 140 billion in 2012 dollars. This is equivalent to $3.5 billion per year in new transmission-related expenses.[6]

The total nameplate capacity of utility-scale solar thermal and solar PV, utility DG solar, and wind power in the DRECP preferred alternative is 14,453 MW. Assuming all of this utility-scale solar thermal and solar PV, utility DG solar, and wind power flow over the new 500 kV lines, the annual generation will be 40 million megawatt-hours (MWh) per year.[7] The unit cost of this new 500 kV transmission would be approximately $90 per MWh of DRECP renewable energy delivered, or $0.09 per kilowatt-hour (kWh) for every kWh delivered.[8]

II. Low cost of rooftop solar/parking lot solar will drive continued growth after net metering ends in 2016 or 2017

The California Energy Commission (CEC) assumes that the state will see a dramatic reduction in rooftop solar installations with the end of the California Solar Initiative and net metering.[9] The CEC projects behind-the-meter solar capacity additions dropping from a peak of about 700 MW in 2013 to 440 MW in 2014, 189 MW in 2015, 234 MW in 2016, and 99 MW in 2017.[10] The CEC forecasts a 10-year customer solar average capacity addition, from 2015 through 2024, of 222 MW per year.[11] The CEC projection, finalized in January 2014, does not take into account the much higher AB 327 net-metering solar targets signed into law in October 2013.[12]

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[3] SDG&E, *Sunrise Powerlink Transmission Project Purpose and Need - Volume 2*, Application No. 05-12-014, p. V-11. “Based on these estimates, SDG&E believes the cost of constructing the Sunrise Powerlink will be $1.265 billion. . . Assuming a 40-year project life and Operating & Maintenance (“O&M”) costs of $10 million per year (in 2010 dollars), the levelized annual costs of the project are estimated at $174 million.” 40 years × $174 million per year = $6.96 billion.
[4] CPUC Decision 08-12-058, *Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project*, December 18, 2008, p. 293. “Order No. 6: A cost cap of $1.883 billion ($2012) is adopted for the Final Environmentally Superior Southern Route.”
[5] $1.883 billion × ($6.96 billion ÷ $1.265 billion) = $10.36 billion.
[6] $140 billion ÷ 40 years = $3.5 billion per year.
[7] Draft DRECP and EIR/EIS, *Appendix F2 - Megawatt Hours and Solar Technology Distribution*, August 2014, p. F2-5. Utility-scale solar generation = 25,877,613 MWh per year, utility DG solar generation = 5,195,561 MWh per year wind generation = 8,983,772 MWh per year. Total annual production = 40,056,946 MWh per year.
[8] $3.5 billion per year ÷ $40 million MWh per year = $88/MWh.
[9] CEC, *California Energy Demand 2014-2024 Final Forecast Mid-Case Final Baseline Demand Forecast Forms*, November 19, 2013, STATEWIDE Mid.xls, STATEWIDE Form 1.2-Mid, “PV” column: http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast/mid_case/
[10] Ibid.
[11] Ibid.
[12] Assembly Bill No. 327 (Cal. 2013).

This very pessimistic DRECP customer self-generation solar projection appears to be the primary basis for the DRECP base case customer solar assumption of 10,000 MW in 2040. The CEC presumes that net metering is critical to the financial viability of customer-owned solar, and that the imminent phase-out of net metering will result in a dramatic retrenchment of rooftop and parking lot solar installations. This presumption is mistaken.

California's investor-owned utilities (IOUs) are in the process of meeting the California Solar Initiative (CSI) solar PV targets.[13] The IOUs were to have 1,940 MW online by December 2016, and appear to have met the CSI targets in late 2014.[14] This solar capacity is installed on the customer side of the electric meter, on rooftops and parking lots primarily, and is known as "net-metered" solar.

The IOUs' net-metered solar targets increased substantially with the passage of AB 327 in October 2013,[15] which enacted Public Utilities Code Section 2827(c)(4)(B) and established minimum statutory net-metering rooftop solar targets to be met by the IOUs no later than mid-2017. AB 327 increased the minimum net-metering cap of the IOUs to 5,256 MW.[16]

This is a 3,316 MW increase over the 1,940 MW CSI target established for the IOUs by the Commission. The IOUs are required by Section 2827(c)(4)(C) to report on a monthly basis their progress in meeting the new minimum solar PV targets by mid-2017.

1,000 MW of rooftop and parking lot solar capacity was added in California in 2013.[17] Approximately 1,300 MW was added in 2014.[18] At current installation rates, with about 2,000 MW of new capacity need to reach the AB 327 net-metering target of 5,256 MW, the goal will be reached by the end of 2016.

Maintaining the actual 1,300 MW self-generation solar installation rate from 2015 through 2040 would add about 34,000 MW of new solar capacity in the state.[19] This is in addition to the 3,000 MW of rooftop and parking lot solar in operation in the state at the end of 2014. This total of 37,000 MW of self-generated solar power in 2040 is far beyond the 10,000 MW of non-utility solar power assumed in the DRECP base case.

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[13] Decision 06-12-033, Opinion Modifying Decision 06-01-024 and Decision 06-08-028 In Response to Senate Bill 1, December 14, 2006, p. 36. Finding of Fact 15: The Commission's ("The Commission" is equivalent to "the IOUs" in this context) 65% share of the 3,000 MW statewide goal is 1,940 MW, and 1,750 MW for the mainstream solar incentive program.

[14] B. Del Chiaro, CALSEIA e-mail to B. Powers, February 17, 2015, regarding capacity of rooftop solar installed in 2014. "At least a 25 – 30 percent increase over 2013 (when ~1,000 MW_{ac} of net-metered solar installed), final numbers still pending."

[15] Assembly Bill No. 327 (Cal. 2013).

[16] Public Utilities Code Section 2827(c)(4)(B): http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=02001-03000&file=2821-2829. SDG&E net-metering target = 607 MW. SCE net-metering target = 2,240 MW. PG&E net-metering target = 2,409 MW. Total of the three IOUs = 5,256 MW.

[17] Renewable Energy World, *California Blows the Lid off Solar Records Installing 1GW of Rooftop Solar in 2013*, January 23, 2014.

[18] B. Del Chiaro, CALSEIA e-mail to B. Powers, February 17, 2015, regarding capacity of rooftop solar installed in 2014. "At least a 25 – 30 percent increase over 2013 (when ~1,000 MW_{ac} of net-metered solar installed), final numbers still pending." 1,000 MW + (0.30 × 1,000 MW) = 1,300 MW.

[19] 1,300 MW-year × 26 years = 33,800 MW.

37,000 MW of self-generated solar power is 27,000 MW more customer self-generated solar power than assumed in the DRECP base case. This amount of customer solar would completely substitute for the utility-scale solar thermal, utility-scale solar PV, utility-scale DG solar, and wind power in the DRECP base case scenario, and provide over 4,000 MW of additional customer solar output.[20,21]

This scenario is also highly likely to occur unless the CPUC authorizes self-generation solar contracts at rates that are well below what the CPUC has already determined the self-generation solar is worth. This will not happen if CPUC follows state law:[22]

> In developing the standard contract or tariff, the commission shall do all of the following:
>
> (1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities.

Customer-sited renewable distributed generation cannot continue to grow sustainably unless the contract rate makes it economic to do so, and state law requires the CPUC to establish contract terms that result in growth in the rate of customer-side solar installations.

III. CPUC estimates rooftop solar is worth about $0.12/kwh now and $0.15/kWh in 2017

The CPUC sets the rates charged by the state's IOUs. It has determined the "avoided cost" of self-generated rooftop and parking lot solar is approximately $0.12/kWh in 2015.[23] This avoided

[20] Draft DRECP and EIR/EIS, *Appendix F2 - Megawatt Hours and Solar Technology Distribution*, August 2014, p. F2-5. Utility-scale solar generation = 25,877,613 MWh per year, utility DG solar generation = 5,195,561 MWh per year wind generation = 8,983,772 MWh per year. Total annual production = 40,056,946 MWh per year.

[21] Customer solar production = 1,752 kWh per year per kW_{ac}, or 1,752 MWh per year per MW_{ac}. Total quantity of customer solar necessary to offset DRECP utility solar and wind power = (40,056,946 MWh per year ÷ 1,752 MWh per year per MW_{ac}) = 22,864 MW_{ac}. The DRECP base case scenario assumes 10,000 MW_{ac} of customer solar. Therefore, amount of additional customer solar production beyond that necessary to displace DRECP utility-scale solar and wind = 37,000 MW_{ac} – 22,864 MW_{ac} – 10,000 MW_{ac} = 4,136 MW_{ac}.

[22] Public Utilities Code Section 2827.1(b): http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=02001-03000&file=2821-2829. "Notwithstanding any other law, the commission shall develop a standard contract or tariff, which may include net energy metering, for eligible customer-generators with a renewable electrical generation facility that is a customer of a large electrical corporation no later than December 31, 2015. The commission may develop the standard contract or tariff prior to December 31, 2015, and may require a large electrical corporation that has reached the net energy metering program limit of subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827 to offer the standard contract or tariff to eligible customer-generators. A large electrical corporation shall offer the standard contract or tariff to an eligible customer-generator beginning July 1, 2017, or prior to that date if ordered to do so by the commission because it has reached the net energy metering program limit of subparagraph (B) of paragraph (4) of subdivision (c) of Section 2827. The commission may revise the standard contract or tariff as appropriate to achieve the objectives of this section. In developing the standard contract or tariff, the commission shall do all of the following:

(1) Ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities."

cost is projected to rise to $0.15/kWh by 2017 and stay relatively constant at this value through 2020.[24] This is the cost that the IOUs would bear to replace the self-generated solar power if it were not being generated.

The CPUC must set rates for self-generated solar power to supersede the current net metering program when it expires.[25] It is reasonable to assume that the rate paid for self-generated solar power in a post net-metering regulatory environment will be in the range of the avoided cost that the CPUC has already calculated for self-generated solar power, or about $0.15/kWh beginning in 2017.

IV. Production cost of commercial and residential rooftop solar will be well below $0.15/kWh in 2017

The DOE-modeled capital cost estimate for a 10 MW solar PV project in 4th quarter 2013 was $1,930/kW$_{dc}$.[26, 27] This is comparable to the $2,000/kW$_{ac}$ capital cost for four 10 MW solar PV projects in New Mexico announced in June 2014.[28] Solar PV contracts are being signed in 2014 at power purchase agreement (PPA) prices less than $50/MWh.[29]

Table 2 summarizes DOE capital cost projections for rooftop and utility-scale solar PV. DOE forecasts that capital cost will decline to as low as $1,300/kW$_{dc}$ for systems 5 MW and up by 2016, as low as 1,500/kW$_{dc}$ for rooftop systems by 2016.[30] Reported system prices of residential and commercial PV systems declined 6 to7 percent per year, on average, from 1998–2013, and by 12 to 15 percent from 2012–2013, depending on system size.[31] The 2016 forecast capital cost ranges shown in Table 2 are consistent with this historic solar PV price decline rate.[32]

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[23] California Public Utilities Commission, *California Net Metering Ratepayer Impacts Evaluation,* October 28, 2013, Figure 14, p. 57.
[24] Ibid, Figure 14, p. 57.
[25] Public Utilities Code Section 2827.1(b).
[26] U.S. DOE, *Photovoltaic System Pricing Trends Historical, Recent, and Near-Term Projections 2014 Edition,* September 22, 2014, p. 22.
[27] DNV KEMA Energy & Sustainability, *Austin Energy Review of Strategic Plan for Local Solar in Austin*, prepared for Austin Energy, November 22, 2013, p. 8, p. 10, and p. 16. Utility-scale solar $\geq$ 5 MW has an assumed dc-to-ac conversion of 90 percent. Therefore a $1,930/kW$_{dc}$ utility-scale solar capital cost equals a kW$_{ac}$ cost of: $1,930/kW$_{dc}$ ÷ 0.9 = $2,144/kW$_{ac}$.
[28] Energy Prospects West, *PNM to Build Four Solar Projects Next Year*, June 10, 2014. "PNM will build four 10-MW photovoltaic solar power projects in 2015 . . . The four projects, which will cost $79 million to build."
[29] GreenTech Media, *Cheapest solar ever? Austin Energy buys at 5 cents per kWh*, March 10, 2014.
[30] U.S. DOE, *Photovoltaic System Pricing Trends Historical, Recent, and Near-Term Projections 2014 Edition*, September 22, 2014, pp. 27-28.
[31] Ibid, p. 4.
[32] Ibid, p. 24. Germany average residential PV installed price in 2013 was $2.05/W$_{dc}$. Hardware costs are fairly similar between the U.S. and Germany. Therefore the gap in total installed prices must reflect differences in soft costs (including installer margins). The German residential PV system cost is reflective of a potential for near-term installed price reductions in the U.S.

Table 2. DOE current and projected capital costs for rooftop and utility-scale (≥ 5 MW) solar PV projects[33]

Type of solar PV	2014 modeled capital cost ($/kW$_{dc}$)	2016 forecast best-case & mid-point capital cost ($/kW$_{dc}$)	2016 forecast in $/kW$_{ac}$ with DC-to-AC conversion[34]
Residential rooftop	3,290	1,500 – 2,250	1,765 – 2,647
Commercial rooftop	2,540	1,500 – 2,250	1,765 – 2,647
Utility-scale, 5 MW	2,030	1,300 – 1,625	1,444 – 1,806

The U.S. Energy Information Administration identifies a fixed O&M cost for solar projects of $27.75/kW-yr.[35]

The current federal solar investment tax credit (ITC) for solar projects, through 2016, is 30 percent.[36] This means that 30 percent of the gross capital cost of the solar project can be deducted from taxes owed the federal government. The ITC will drop from 30 percent to 10 percent after 2016 for commercial and utility-scale projects.[37] The ITC will be eliminated for residential projects.[38] In addition to the ITC, commercial and utility solar projects are also eligible for accelerated depreciation of the net capital cost of the solar project after deducting the ITC. Accelerated depreciation has the effect of reducing the net capital cost by an additional 28 percent when the ITC is 30 percent.[39] Accelerated depreciation will reduce the net capital cost by 36 percent when the ITC is reduced to 10 percent.[40]

The 2016 production cost of residential rooftop solar, commercial rooftop solar, and utility-scale (> 5 MW) solar, based on DOE projections of best-in-class and mid-range capital, are provided in Table 3. These costs are provided with the current ITC of 30 percent and the post-2016 ITC of 10 percent. The calculations supporting these cost ranges are provided in **Attachment A**.

[33] Ibid, p. 4, p. 22 (5 MW system at $2.03/W),
[34] DNV KEMA Energy & Sustainability, *Austin Energy Review of Strategic Plan for Local Solar in Austin*, prepared for Austin Energy, November 22, 2013, p. 8, p. 10, and p. 16. For residential and commercial rooftop -scale solar, the dc-to-ac conversion is assumed to be 85 percent. Utility-scale solar ≥ 5 MW has an assumed dc-to-ac conversion of 90 percent.
[35] U.S. EIA, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*, April 2013, Table 1, p. 6.
[36] DNV KEMA Energy & Sustainability, *Austin Energy Review of Strategic Plan for Local Solar in Austin*, prepared for Austin Energy, November 22, 2013, p. 8 and p. 10,
[37] Ibid, p. 8 and p. 10.
[38] Solar investment tax credit description: http://www.seia.org/policy/finance-tax/solar-investment-tax-credit.
[39] Net capital cost after deducting the 30 percent ITC = 1.0 – 0.3 = 0.7. Corporate tax rate is 40 percent. Therefore accelerated depreciation will reduce net capital cost by: 0.7 × 0.4 = 0.28 (28 percent).
[40] Net capital cost after deducting the 10 percent ITC = 1.0 – 0.1 = 0.9. Corporate tax rate is 40 percent. Therefore accelerated depreciation will reduce net capital cost by: 0.9 × 0.4 = 0.36 (36 percent).

Table 3. Production cost with 30 percent ITC through 2016 (all solar projects), 10 percent ITC post 2016 (commercial/utility-scale projects), 0 percent ITC post 2016 (residential)

ITC	Residential rooftop production cost range [$/kWh]	Commercial rooftop production cost range [$/kWh]	Utility-scale solar production cost range [$/kWh]
30% (thru 2016)	0.072 – 0.101	0.050 – 0.072	0.036 – 0.041
10% (post 2016)	--	0.059 – 0.081	0.042 – 0.049
0% (post 2016)	0.097 – 0.137	--	--

The post-2016 production cost of commercial rooftop and parking lot solar, at $0.06 – 0.08/kWh, will be about one-half the $0.15/kWh avoided cost in 2017 to replace this solar power as identified by the CPUC. The post-2016 production cost of residential rooftop solar, at $0.097 – 0.137/kWh, will be substantially below the $0.15/kWh avoided cost. Commercial and residential customers will continue to have an economic incentive to install on-site solar after the end of net metering in California and reductions to the federal solar ITC after 2016.

It is reasonable to assume that commercial and residential rooftop solar installation rates will continue to expand in the post-2016 regulatory environment and not contract as assumed in the draft DRECP and DEIR/EIS.

Both the CEC and the draft DRECP and DEIR/EIS assume customer rooftop solar installations will come to a near halt in 2017 due to the end of net-metering and the reduction in the federal ITC for solar projects. This is a mistaken assumption not supported by evidence or current California law that requires "that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably."[41]

V. California has 100,000 MW of rooftop/parking capacity available to be developed

Approximately 3,000 MW of customer rooftop and parking lot solar had been developed in California by the end of 2014.[42,43] The estimated customer rooftop and parking lot solar resource potential in California is in the range of 100,000 MW.

Navigant Consulting, under contract to the CEC,[44] determined in 2007 that California will have about 170,000 MW of total residential rooftop solar potential in 2016, and about 40,000 MW of

[41] Public Utilities Code Section 2827.1(b).
[42] Renewable Energy World, *California Blows the Lid off Solar Records Installing 1GW of Rooftop Solar in 2013*, January 23, 2014. "California is closing out the year with more than 2,000 MW of rooftop solar systems installed statewide."
[43] B. Del Chiaro, CALSEIA e-mail to B. Powers, February 17, 2015, regarding capacity of rooftop solar installed in 2014. "At least a 25 – 30 percent increase over 2013 (when ~1,000 MW_{ac} of net-metered solar installed), final numbers still pending." 1,000 MW + (0.30 × 1,000 MW) = 1,300 MW.

total commercial rooftop solar potential in 2016. Of these amounts, Navigant assumes only 22 to 27 percent of residential rooftop potential can be developed, and only 60 to 65 percent of the commercial rooftop potential can be developed. This reduces California-wide 2016 rooftop "technical" solar potential to 42,181 MW of residential rooftop solar and 25,708 MW of commercial rooftop solar, a total of approximately 68,000 MW.[45]

Commercial parking lot solar is another major category of customer-side distributed solar. Powers Engineering estimates total commercial parking lot potential in California at 158,000 MW based on data developed at UCLA on number and area of commercial parking spaces per capita in California. Assuming 25 percent of this parking lot potential is relatively free of shading, the net amount of commercial parking lot space that can be developed in California based on the California population in July 2013 is approximately 40,000 MW. See **Attachment B** for commercial parking lot solar potential supporting calculations.

The combined absolute potential of California residential rooftop solar, commercial rooftop solar, and commercial parking lot solar in 2016, assuming no shading, building orientation, or rooftop obstruction impediments, would be approximately 370,000 MW. The combined 2016 technical potential of these three categories of customer-side distributed solar resources, taking into consideration reasonable assumptions regarding shading, building orientation, and rooftop obstructions, is about 108,000 MW.

VI. The distribution grid is undergoing modernization for full two-way flow capability on all distribution circuits

The state's IOUs have had a grid modernization effort underway for many years. Even without this modernization effort, the distribution grid can accept large amounts of customer solar without causing safety equipment such as circuit breakers, relays, and reclosers, to "see" reverse flow on the circuit caused by rooftop solar as a fault condition and affect grid reliability.

As a component of the DG feed-in tariff development process in 2009, the CPUC Energy Division requested data on peak loads at all distribution substations from the IOUs and compiled that information graphically as shown in Figure 1. According to the CPUC, this data was obtained from IOU distribution engineers.[46] The Energy Division staff opined that because solar is a daytime resource, it was very unlikely that the load on any given distribution substation would be less than 30 percent of peak load when solar power is being generated.

This means that a distribution substation with a 50 MW peak load will have a load of at least 15 MW during the time period when solar power is being produced. Therefore at least 15 MW of distributed solar could be fed to the distribution substation without reversing the normal one-way

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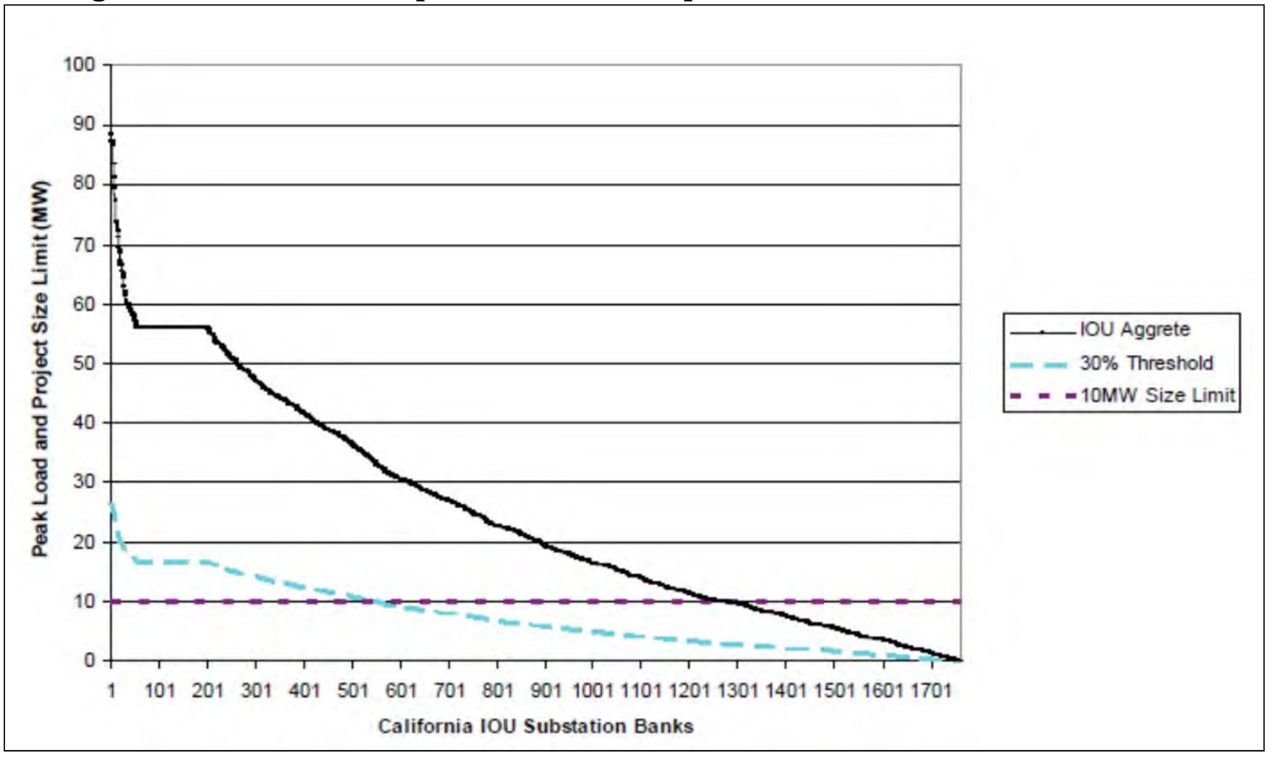
[44] Navigant, *California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential by County*, PIER Final Project Report, September 2007, APPENDIX B: RESULTS, Table B.1: Technical Potential by County (MWp), p. B-2 and p. B-3.
[45] Ibid,
[46] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, pp. 15-16.

flow from the distribution substation and causing older analog protective devices, circuit breakers or relays, to see the flow reversal as a fault condition.

A minimum of approximately 13,300 MW of PV can be connected directly to IOU substation load banks without concern for flow reversal based on the data in Figure 1. The supporting calculations for this estimate are provided in Table 4. The minimum may in fact be much higher, as individual distribution substations and associated circuits may have much higher minimum daylight loads than 30 percent of peak load.

The IOUs provide about two-thirds of electric power supplied in California, with publicly-owned utilities like the Los Angeles Department of Water & Power and the Sacramento Municipal Utility District and others providing the rest.[47] Assuming the substation capacity pattern in Figure 1 is also representative of the non-IOU substations, the total California-wide PV that could be interconnected at substation low-side load banks with no substantive substation upgrades would be [13,300/(2/3)] = 19,950 MW.

Figure 1. IOU Substation peak loads, 30% of peak load, and 10 MW reference line



[47] CEC, *2007 Integrated Energy Policy Report*, December 2007, Figure 1-11, p. 27.

Table 4. Calculation of distributed PV interconnection capacity to existing IOU substations with minimal interconnection cost from data in Figure 1

Substation range	Number of substations	Calculation of distributed PV that could be interconnected with minimal substation upgrades (MW)	Total distributed PV potential (MW)
1-200	200	average peak ~60 MW x 0.30 = 18 MW	3,600
201-500	300	average peak ~45 MW x 0.30 = 13.5 MW	4,000
501-800	300	average peak ~30 MW x 0.30 = 9 MW	2,700
801-1,000	200	average peak ~20 MW x 0.30 = 6 MW	1,200
1,001-1,600	600	average peak ~10 MW x 0.30 = 3 MW	1,800
		Distributed PV total:	13,300

In sum, a minimum of approximately 20,000 MW of distributed PV interconnection capacity was available in California in 2009 that would require little or no substation upgrading to accommodate the distribution level PV.

The most recent incarnation of this grid modernization effort is known as smart grid deployment. "Smart Grid," as defined in the State of California by Senate Bill (SB) 17 (Padilla, 2009), is a fundamental change in the existing electricity infrastructure that utilizes advances in technology to create a better, safer, greener electricity supply.[48] The state's IOUs spent more than $1 billion in fiscal year 2013-2014 on smart grid relative modernization, primarily focused on distribution and transmission system modernization.[49] The CPUC describes smart grid modernization in the following manner:[50]

> Grid modernization in some form has been an ongoing practice of the utilities, where economically feasible and supported via CPUC authorization in the General Rate Case (GRC). New developments in technology, as well as direction from regulators, have emphasized some trends.
>
> The accelerating adoption of customer-side intermittent renewable generation, primarily solar and wind has produced new operational challenges for the grid. In addition, greatly increased small-scale distributed generation is creating more pressure on utilities to change their business models to provide "plug and play" support for these resources. Providing an infrastructure platform for customer choice is becoming a priority.
>
> The new distribution resources planning effort now underway will guide new investment requests in future GRCs to meet these challenges. Distribution Resources Plans will enable much greater use of distributed energy resources (DER) than traditional processes have previously allowed.

[48] CPUC, *Annual Report to the Governor and the Legislature California Smart Grid per Senate Bill 17 (Padilla, 2009)*, January 2015.
[49] Ibid, p. 2.
[50] Ibid, p. 3.

The state's utilities are required to file Distribution Resources Plan applications by July 2015.[51] Distribution Resource Plan implementation by the utilities will require greater situational awareness, monitoring and control sensors and systems to support high penetrations of DER. Investment to support further development of these systems is now required. GRC cycles have begun to incorporate more spending on automation and grid enhancements to further the Smart Grid goals.

Safety hardware on the distribution grid, such as circuit breakers and reclosers, are being methodically replaced with microprocessor-based equivalents that all full two-way power flow on the distribution system. For example, PG&E states in its 2014 Smart Grid Annual Report that 65 percent of its 2,102 distribution circuits are equipped with automation or remote control equipment.[52] What this means in lay terms is that these circuits are capable of full two-way flow, with no restrictions on the amount of customer on-site solar due to the limitations of safety hardware on the distribution circuit or at the distribution substation.

PG&E also states that it will achieve 100 percent visibility and control of all critical distribution substation breakers by 2018, adding or replacing supervisory control and data acquisition (SCADA) for approximately 393 substations and approximately 1,107 breakers.[53] At this pace of grid modernization, full two-way flow capability on the distribution system will not be an obstacle to rapid expansion of customer solar in California.

SCE notes in its 2014 Smart Grid Annual Report on the new energy storage procurement targets the IOUs must meet:[54]

> The (October 2013 CPUC energy storage) decision established the policies and mechanisms for procurement of electric energy storage pursuant to AB 2514, setting an energy storage procurement target for the IOUs of 1,325 MW by 2020. Furthermore, the decision directs the IOUs to file separate applications containing a proposal for their first energy storage procurement period by March 1, 2014. SCE submitted its "Application of its 2014 Energy Storage Procurement Plan" and associated testimony on February 28, 2014.

Large amounts of storage on the grid will enhance the ability of the grid to manage variable resources like customer solar.

SCE also reports that as of June 30, 2013 it had 4,617 distribution circuits in operation of which 2,538 are automated with remote control switches. This means that 55 percent of these circuits can be remotely monitored and controlled through SCE's existing distribution management system to protect critical distribution equipment, restore outages, and minimize customer

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[51] Ibid, p. 5.
[52] PG&E, *Annual Report of Pacific Gas and Electric Company (U 39 E) on Status of Smart Grid Investments Pursuant to Ordering Paragraph 15 of D. 10-06-047*, October 1, 2014, p. 77.
[53] Ibid, p. 27.
[54] SCE, *Southern California Edison Company's (U 338-E) Annual Report on the Status of Smart Grid Investments*, October 1, 2014, p. 5

minutes interrupted.[55] These microprocessor-based protective devices also facilitate two-way flow on the distribution circuit.

SDG&E underscores its leadership on smart solar inverters to facilitate much higher levels of customer solar power on the distribution grid:[56]

> SDG&E is actively engaged with manufacturers, the CPUC, and CEC to incorporate advanced functionality in inverters and mandate their adoption in California. The proposed inverters would securely communicate with utility operations systems while also potentially addressing the concerns related to the intermittency of solar generation when coupled with the right tariff incentives. In support of the implementation of smart inverters, SDG&E has worked with the other California IOUs on recommendations submitted to the CPUC through the Rule 21 proceeding.

SDG&E also reports that 79 percent of its distribution circuits equipped with automation or remote control equipment, including SCADA systems.[57] In lay English, this means these distribution circuits are fully capable of handling two-way power flows.

The DRECP relies on the following unsupported and obsolete statements about the current status of the distribution grid as the basis for not including a behind-the-meter customer solar alternative:

> Page II.8-7: "*For a variety of reasons (e.g., upper limits on integrating distributed generation into the electric grid, cost, lack of electricity storage in most systems, and continued dependency of buildings on grid-supplied power), distributed energy generation alone cannot meet the goals for renewable energy development.*"

> Page II.8-7: "*Integration and reliability concerns were highlighted due to local renewable generation being sent to the grid through power lines and equipment that were primarily designed to transport energy in the opposite direction. Unless managed appropriately, the integration of local renewable energy can impact the safe and reliable operation of distribution grids.*"

Upper limits on integrating distributed generation into the electric grid are rapidly disappearing as a result of utility distribution grid modernization programs. The DRECP targets are for 2040. California's utilities have been mandated to modernize the grid to accept large inflows of local solar power feeding into distribution circuits. Utility customers are spending over $1 billion per year to accomplish the necessary modernization upgrades. It would appear, based on the most recent IOU smart grid annual reports, that each of the state's three IOUs are more than half way toward having full two-way flow capability on all distribution circuits. It is reasonable to assume,

[55] Ibid, p. 57.
[56] SDG&E, *Annual Report of SDG&E for Smart Grid Deployments and Investments*, October 1, 2014, p. 7.

[57] Ibid, p. 94.

with the current level of investment, that the utility grid modernization effort will continue to stay in front of the expansion of customer solar power over the next 25 years.

VII. Conclusion

A major flaw in the DRECP is the failure to include a behind-the-meter local solar alternative as the "no action" alternative to the targeted renewable energy generation levels in the DRECP study area for utility-scale solar, utility DG solar, and wind power. The local solar "no action" alternative is the most likely scenario given: current behind-the-meter solar installation rates of more than 1,000 MW per year, the cost-competitiveness of behind-the-meter solar compared to utility power with or without net-metering, state law mandating that the CPUC support sustained growth of behind-the-meter solar installations through appropriate rate design after net-metering expires, and the state's ongoing commitment to smart grid modernization of the existing distribution grid to allow it to fully accept two-way power flows and eliminate distribution grid reliability issues as a brake on customer-provided local solar development. In addition, the local solar "no action" alternative would eliminate the $140 billion life-of-project cost and environmental impact of 13 to 14 new 500 kV transmission lines assumed in all DRECP scenarios.

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Attachment A: Cost of Generation, Commercial, Residential, and Utility-Scale Solar

B. Powers, Powers Engineering, February 22, 2015

I. Commercial rooftop and parking lot solar, cost of generation

Assumptions:

- Annual average fixed array, behind-the-meter capacity factor (CF): 0.20
- Average annual production per kW_{ac} of capacity at CF of 0.20: 1 kW_{ac} × 8,760 hr/yr × 0.20 = 1,752 kWh/yr
- Commercial rooftop solar 2016 DOE best-in-class gross capital cost: \$1,765/kW_{ac}
- Commercial rooftop solar 2016 DOE mid-range gross capital cost: \$2,647/kW_{ac}
- Commercial solar federal income tax credit (ITC) through 2016:[1] 30 percent
- Commercial solar federal ITC after 2016:[2] 10 percent
- Net capital cost when adjusted for accelerated depreciation, commercial solar: (net capital cost after ITC) × (corporate tax rate)
- Tax rate used to calculate value of accelerated depreciation:[3] 40 percent
- Capital recovery factor, 5 percent interest, 20-year term:[4,5] 0.0802
- Residential rooftop solar 2016 DOE best-in-class gross capital cost; \$1,765/kW_{ac}
- Residential rooftop solar 2016 DOE mid-range gross capital cost: \$2,647/kW_{ac}
- Residential solar federal income tax credit (ITC) through 2016: 30 percent
- Residential solar federal ITC after 2016:[6] 0 percent
- Net capital cost when adjusted for accelerated depreciation, residential solar: No change, not eligible to use accelerated depreciation

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[1] Solar investment tax credit description: http://www.seia.org/policy/finance-tax/solar-investment-tax-credit
[2] Ibid.
[3] Corporate tax rates, all countries: http://www.kpmg.com/global/en/services/tax/tax-tools-and-resources/pages/corporate-tax-rates-table.aspx
[4] Representative commercial construction loan interest rate, ~5% interest, 15-20 year term: https://www.commercialloandirect.com/commercial-rates.php#ConstructionLoanInterestRates.
[5] M. Lindeburg, *Mechanical Engineering Review Manual – 6th Edition, Chapter 2: Engineering Economy*, 1980, p. 2-26
[6] Solar investment tax credit description: http://www.seia.org/policy/finance-tax/solar-investment-tax-credit.

A. *Through 2016, with 30 percent ITC and accelerated depreciation – best in class 2016 DOE forecast capital cost:*

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 30% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
1,765	1,236	741	59.43	27.75	87.18	0.050

B. *Through 2016, with 30 percent ITC and accelerated depreciation – mid-range 2016 DOE forecast capital cost:*

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 30% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
2,647	1,853	1,112	89.18	27.75	126.93	0.072

C. *After 2016, with 10 percent ITC and accelerated depreciation – best in class 2016 DOE forecast capital cost:*

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 10% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
1,765	1,588	953	76.43	27.75	104.18	0.059

D. After 2016, with 10 percent ITC and accelerated depreciation – mid-range 2016 DOE forecast capital cost:

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 10% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
2,647	2,382	1,429	114.61	27.75	142.36	0.081

II. Residential rooftop solar, cost of generation

A. Through 2016, with 30 percent ITC, no accelerated depreciation – best in class 2016 DOE forecast capital cost:

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 30% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
1,765	1,236	NA	99.13	27.75	126.88	0.072

NA = not applicable

B. Through 2016, with 30 percent ITC, no accelerated depreciation – mid-range 2016 DOE forecast capital cost:

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 30% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
2,647	1,853	NA	148.61	27.75	176.36	0.101

NA = not applicable

C. After 2016, with 10 percent ITC, no accelerated depreciation – best in class 2016 DOE forecast capital cost:

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 0% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
1,765	1,765	NA	141.55	27.75	169.30	0.097

NA = not applicable

D. After 2016, with 10 percent ITC, no accelerated depreciation – mid-range 2016 DOE forecast capital cost:

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 0% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
2,647	2,647	NA	212.29	27.75	240.04	0.137

NA = not applicable

III. Utility-scale solar (≥ 5 MW), cost of generation

- Annual average utility-scale solar DRECP capacity factor (CF), 2,150 hr of 8,760 hr/yr: 0.245
- Average annual production per kW$_{ac}$ of capacity at CF of 0.245: 1 kW$_{ac}$ × 8,760 hr/yr × 0.245 = 2,146 kWh/yr
- Commercial rooftop solar 2016 DOE best-in-class gross capital cost: $1,444/kW$_{ac}$
- Commercial rooftop solar 2016 DOE mid-range gross capital cost: $1,806/kW$_{ac}$
- Commercial solar federal ITC through 2016: 30 percent
- Commercial solar federal ITC after 2016: 10 percent
- Net capital cost when adjusted for accelerated depreciation, commercial solar: (net capital cost after ITC) × (corporate tax rate)
- Tax rate used to calculate value of accelerated depreciation: 40 percent
- Capital recovery factor, 5 percent interest, 20-year term: 0.0802

A. Through 2016, with 30 percent ITC and accelerated depreciation – best in class 2016 DOE forecast capital cost:

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 30% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
1,444	1,011	607	48.68	27.75	76.43	0.036

B. Through 2016, with 30 percent ITC and accelerated depreciation – mid-range 2016 DOE forecast capital cost:

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 30% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
1,806	1,264	759	60.87	27.75	88.62	0.041

C. After 2016, with 10 percent ITC and accelerated depreciation – best in class 2016 DOE forecast capital cost:

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 10% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
1,444	1,300	780	62.56	27.75	90.31	0.042

D. After 2016, with 10 percent ITC and accelerated depreciation – mid-range 2016 DOE forecast capital cost:

Gross capital cost, [$/kW$_{ac}$]	Net capital cost – 10% ITC, [$/kW$_{ac}$]	Net capital cost, adjust for accelerated depreciation, [$/kW$_{ac}$]	Annualized net capital cost, at 5% interest, 20 years, [$/kW$_{ac}$-yr]	O&M cost, [$/kW$_{ac}$-yr]	Total annual cost, capital + O&M, [$/kW$_{ac}$]	Cost of generation, @ 1,752 kWh-yr per kW$_{ac}$ [$/kWh]
1,806	1,625	975	78.21	27.75	105.96	0.049

Attachment B: Parking Lot Solar Potential in California

B. Powers, Powers Engineering, December 15, 2014

The methodology utilized to calculate the PV technical potential of ground-level parking lots and parking structures in California is shown in Table 1. A core assumption in the methodology is that only 25 percent of total estimated parking surface is sufficiently open, meaning not shaded to a significant degree, so that its full solar potential can be realized. The estimated ground-level parking lot and parking structure PV potential in California, assuming 25 percent of the total surface area is utilized for PV, is 39,500 MW_{ac}.

Table 1. Assumptions Used to Estimate PV Potential of Parking Lots – California

Assumption	Source
771 vehicles per 1,000 citizens	Dr. Donald Shoup, urban planning, UCLA[1]
At least 4 parking spaces per vehicle, one of which is residential space	Dr. Donald Shoup, urban planning, UCLA
38,332,521	July 1, 2013 California population estimate: http://quickfacts.census.gov/qfd/states/06000.html
162 square feet per parking space	Square footage of typical 9-foot by 18-foot parking space, Envision Solar, San Diego[2]
Approximately 88,663,000 non-residential parking spaces in California	Calculated value: 38,332,521 × (771/1,000) × 3 spaces [4 total spaces per car – 1 residential space per car] = 88,663,000 non-residential spaces
11 W_{ac} per square foot PV capacity per square foot of parking area	Envision Solar, San Diego[3]
158,000 MW_{ac} parking lot PV theoretical potential in California without considering shading	88,663,000 spaces × 162 square feet per space × 11 W_{ac} per square feet × 1 MW_{ac} per million W_{ac} = 158,000 MW_{ac} parking lot PV potential
39,500 MW_{ac} actual potential in California	Rough estimate of actual PV potential - assumes 25 percent of non-residential parking spaces are unshaded throughout the day and full PV potential can be realized at these sites

[1] Dr. Donald Shoup, *The High Cost of Free Parking*, March 2005, published by American Planning Association, Chapter 1.
[2] Jim Trauth, Envision Solar, estimate of solar parking lot potential in San Diego County, e-mail to Bill Powers, June 13, 2007.
[3] Ibid.