December 18, 2013

***VIA* Electronic Mail** – docket@energy.ca.gov, Matt.Coldwell@energy.ca.gov

California Energy Commission
Re: Distributed Generation Integration Cost Study, Docket #13-IEP-1H
Publications, MS-5
1516 Ninth Street
Sacramento, CA 95814-5504

RE: Docket #13-IEP-1H, Distributed Generation Integration Cost Study

Mr. Coldwell:

The Vote Solar Initiative (Vote Solar) would like to thank you for the opportunity to provide comments on the approach, findings, and next steps for the California Energy Commission's (Commission) recently released *Distributed Generation Integration Cost Study: Analytical Framework* (Study). The Study was prepared by Navigant Consulting for the Commission and was made public in the Notice of Availability and Request for Comments, posted December 3, 2013.

Vote Solar is a non-profit grassroots organization working to fight climate change and foster economic opportunity by bringing solar energy into the mainstream. Since 2002, Vote Solar has engaged in state, local and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. We support the Commission's efforts to help achieve Governor Brown's goal of at least 12,000 MW of clean distributed generation (DG) statewide by 2020 via efficient and cost-effective means.

I. Comments on Study Approach and Findings

We support the Commission's approach of using Southern California Edison's report titled *The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System* (May 2012) (SCE LER Report) as a starting point for independent analysis of the cost impacts associated with meeting the Governor's clean DG goal. In particular, we appreciate the Commission's effort to identify a method for quantifying how the costs of integrating DG[1] into California's electrical grid change based on interconnection location, distribution feeder characteristics, load types, and project size. SCE's LER Report generally found the need for transmission and

[1] The Report defines DG generally as "projects sized 20 MW or fewer, interconnected on-site or close to load, that can be constructed quickly with no new transmission lines, and, typically, with no environmental impact."

distribution upgrades depends on the voltage of the distribution line at the point of interconnection, the number of generators and their sizes and locations on the distribution line, the configuration of the distribution line, the ratio of generation capacity to load, and the extent to which generation primarily services onsite or local load.[2] Accordingly, seeking to confirm the findings of the study via a similar granular but non-overly prescriptive approach made imminent sense.

Some of the Navigant Study's conclusions include:

- Generally, integration impacts and costs are lower when DG is installed in urban areas, where feeders are shorter and often equipped with larger conductor or cable along the entire length of the circuit.
- DG integration costs increase significantly as greater amounts of DG are clustered and installed near the end of distribution lines.
- Distribution planning and operational criteria and practices that ensure minimal impact to reliability and system operability can limit DG integration even on feeders where DG does not create loading or voltage violations.
- High-penetration DG may require sophisticated communications and control systems to better manage DG impacts and reduce integration costs.
- Advances in smart system technology and changes in industry standards may provide an opportunity to enable greater amounts of DG at lower cost.
- Policies that guide or encourage DG in areas with fewer impacts would minimize grid integration costs; however, the lowest total cost solutions would need to factor in the procurement costs of the systems themselves.
- Results from this study, including variations in DG capacity by location, may provide guidance to the next DG deliverability study the California ISO will conduct in early 2014.[3]

After careful review of the Study, we believe its findings are generally reasonable and that, collectively, these findings will prove helpful in future conversations across a number of activities at this Commission, the California Public Utilities Commission (CPUC) and the California ISO. For example, under newly enacted Public Utilities Code Section 769, the state's investor-owned utilities will be required to submit distribution resource plans that identify optimal locations on the grid for deployment of distributed resources (defined in the statute as renewable DG, energy efficiency, energy storage, electric vehicles, and demand response technologies). Of particular note was the study's confirmation, generally, that a mix of DG that is primarily located in urban areas will result in significantly lower overall integration costs than a scenario where DG is primarily located in rural areas.[4] However, deeper changes to utility business models may ultimately be necessary to support the full integration of DG potential envisioned in the Governor's DG goal, consumers' growing preferences for self-generation, and other

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[2] See SCE LER Report at p. 15.
[3] See Study at pp. 55-56.
[4] See Study at pp. 8, 10-12 (discussing Integration Scenarios).

state policy preferences for energy efficiency, demand response, and DG as preferred resources.

In addition to that particular finding, the SCE LER Report also found that for large generators, upgrades are less likely if DG is located closer to the substation.[5] Discussion in the most recent Biennal Report *on Impacts of Distributed Generation* (B&V Report), produced annually pursuant to Assembly Bill 578 (Blakeslee, 2008), supports this point noting that “the location of the DG system along the radial distribution circuit – i.e., whether it is near the end of the line – may be the most important factor, in combination with the amount of load in the immediate vicinity.”[6] Similarly, Rule 21 recognizes that the hosting capacity of the distribution system is greater close to the substation under Screen P.[7] We believe this finding should be considered as stakeholders begin discussions in the future on guiding DG resources to preferable locations.

Lastly, the B&V Report provides additional support and context for the finding in this Study and the SCE LER Report that clustering of DG systems can lead to increased grid impacts noting that “in most cases a larger number of smaller DG systems spread over a wide area will have less negative impact than a smaller number of large systems concentrated in a single area.”[8] This is especially true for variable resources like solar PV and wind, whose variability is “smoothed out” when aggregating the output of many generators over wide geographic areas.[9]

We also appreciate the Commission’s recognition that system *benefits* provided by DG are not included in the current evaluation and that the California Public Utilities Commission (CPUC) is undertaking such an evaluation at this time. A clear understanding of costs and benefits will be necessary to inform policy making on topics related to DG and we appreciate efforts at both agencies to develop the necessary information to guide discussions by all stakeholders as California continues to lead the nation in deployment of renewable DG resources.

II. Comments on Next Steps

We believe that discussion based on the findings of this Study should also recognize the changing preferences of energy consumers. Recognition of this evolution is important as customer-sited DG installations, specifically solar PV, have already reached 1907 MW of

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[5] See SCE LER Report at p. 25.
[6] See B&V Report at pp. 4-10.
[7] See, e.g. Pacific Gas & Electric Company, Rule 21, Section G.2.c. (Screen P screens for potential safety and reliability impacts at high penetration levels and notes that impacts are less likely if a generating facility is located in close proximity to the substation (i.e. < 2.5 electrical line miles), and is the distribution line from the substation to the customer composed of large conductor/cable (i.e. 600A class cable).”
[8] B&V Report at pp. 1-6.
[9] See Id. See also Mills, Andrew and Wiser, Ryan, Implications of Wide-Area Geographic Diversity for Short-term Variability of Solar Power, Ernest Orlando Lawrence Berekeley National Laboratory, September 2010.

installed capacity[10] and will continue to grow as more energy consumers take advantage of California's pioneering net energy metering and other DG policies.[11] Many observers think it likely that customers in the three IOU territories will have installed at least 5200 MW of net metered systems by 2017. While the discussion in Next Steps appears to recognize the likelihood of continued growth in customer-sited DG, it does not appear that this growth is fully contemplated within the Next Steps section. We believe it is fundamentally important that California policymakers continue to seek to harness customer interest in investing in clean energy resources to self-generate as the one of the core methods to achieve the Governor's renewable DG goals.

Moreover, and perhaps most importantly for future efforts, it is important to recognize that customer-sited DG tends to be the very type of DG that can avoid many of the factors that lead to increased integration costs identified in the SCE LER Report and the current Study. This is because these systems tend to be dispersed, smaller in size, interconnected on the customer-side of the meter, largely located on urban and suburban circuits, and generally serve local load. Moreover, customer-sited DG inherently addresses many of the land-use and environmental considerations mentioned in the Next Steps section by virtue of their smaller size and location in urban and suburban areas. We support the Study's proposal to undertake a statewide planning process pilot to identify and evaluate areas of the grid that are best suited to accommodate DG and we believe customer-sited DG and efforts to support it should be considered within the pilot. For example, California's interconnection cost waiver is one policy that supports the installation of customer-sited DG, for example.

For wholesale generation, where a developer has a choice in where to site a facility, a number of tools exist to help DG developers identify locations that have lower interconnection costs including online mapping tools developed by the utilities to identify areas of the grid with available distribution capacity. However, more can be done to refine these mapping tools to provide more granular information so that areas of the grid with higher interconnection costs are better identified even if capacity is available in a particular area. The findings of this study could be used as a first step in granularizing these maps. Additionally, interconnection queue data is being posted by the IOUs to highlight projects that may eat into the existing capacity highlighted on utility maps, but more could be done to bring these two pieces of information together. Lastly, the CPUC recently incorporated an opportunity for developers to request a pre-application report which would provide more granular information on the conditions relevant to interconnection at a particular point on the grid. Each of these efforts is important to help achieve California's overall DG goals in a least-cost manner, and take valuable steps towards sending the types of transparent price signals to developers mentioned in the Study so that they can make informed decisions on where to locate projects.

We are encouraged by the discussion in the Next Steps section about efforts by the

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[10] See http://gosolarcalifornia.org.

[11] Senate Bill 43 will support the development of 600 MW of shared renewable energy facilities in California across the three largest investor-owned utilities, some of which is likely to be customer-sited although not behind the meter

Commission and the California ISO to include an analysis of transmission integration costs, as that is an important piece of addressing overall costs of deployment of DG resources. However, we also believe the Commission can play an important role in encouraging the California ISO to improve consideration of non-transmission alternatives (NTAs) during the transmission planning process. Robust consideration of NTAs is required under FERC Order 1000[12], but also makes good sense given the findings of this Study. Moreover, development of non-wires alternatives during the planning process can facilitate sending direct and transparent price signals to developers regarding which areas of the grid would most benefit from DG deployment. When evaluated in the context of other preferred resources like energy efficiency, demand response, and energy storage, DG can be a powerful driver for cost reductions overall. Examples of how energy efficiency, demand response, and DG can successfully defer transmission investment include:

- Con Edison in New York has included demand-side management in its capital planning processes since 2003 to help reduce need for over $1 billion in capital investment in T&D systems. Additionally, Con Edison has used geo-targeted efficiency programs to defer T&D system upgrades in more than one-third of its distribution networks with direct savings of over $75 million above the cost of the EE measures. When the other benefits of EE were included in the analysis, Con Edison and its customers saved over $300 million dollars. An additional benefit from using DSM to defer projects is that the additional time allowed uncertainties in forecasting to resolve themselves such that Con Edison estimated that up to $85 million in capacity extensions were further deferred or avoided all together once data on load growth became clearer.[13]
- The Long Island Power Authority (LIPA) was facing an immediate need to invest approximately $64 million in transmission upgrades east of its Canal substation, and further transmission additions and additional generation will be required to meet projected future load growth. LIPA has determined that targeted application of solar PV generation in this area could defer immediate investment and defer future expenditures, resulting in an estimated net present value savings of $60 million, assuming that 40 MW of solar PV generation can be developed at these locations. A number of distribution substations have been identified as preferred locations, and LIPA's proposal requests authorization to pay a cost-based

12 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011), 76 Fed. Reg. 49842 (August 11, 2011), (hereinafter "Order 1000"); *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A ¶ 336, 77 Fed. Reg. 32,184 (May 31, 2012), 139 FERC Stats. & Regs. ¶ 61,132 (2012) (Order on Rehearing and Clarification).

13 *See* Chris Gazze and Massarlain, M., "*Planning for* Efficiency", Public Utilities Fortnightly, August 2011. PowerPoint by Madlen Massarlian and Michael Harrington, Con Edison, *Integrated Planning and Targeted DSM,* June 2012 Webinar on EE as a T&D Resource, available at http://www.raponline.org/. See also, *US Experience with Energy Efficiency as a Transmission and Distribution Resource,* February 2012*, www.raponline.org/document/download/id/4765*

premium of $0.070 per kWh to bidders who will attach solar PV to circuits originating out of any of these substations.[14] LIPA's proposal represents one means California could utilize in providing direct and transparent price signals to developers of both wholesale and retail projects to target their activities in these areas.

- The ISO-NE determined that ten proposed transmission projects, totaling approximately $260 million, were able to be deferred after applying energy efficiency forecasting within its transmission planning process.
- A paper by Plunkett and Bentley (2008 ACEEE summer study), which describes efforts by Central Vermont Public Service Company to avoid transmission costs via targeted EE and CHP systems.[15]
- CHP development in the Midwest region, which is under discussion as a means to help resolve system reliability issues associated with coal-fired power plant retirement driven by federal air quality requirements.[16]

Lastly, for both wholesale and retail DG deployment, upcoming discussion regarding the distribution resource plans to be developed pursuant to AB 327 represents another logical forum to begin integrating DG and other preferred resources into utility distribution system planning. We believe California's investor-owned utilities are capable of such a robust, proactive and detailed planning. SCE's 2012 rate case demonstrates this potential. In its testimony, SCE describes how it performed a "circuit-by-circuit" analysis of where plug-in electric vehicles (EVs) will be located on its distribution system.[17] The analysis supported a proposal to spend $70 million to prepare SCE's distribution system to accommodate what is a nascent factor in load growth analysis. The interconnection queues and the California Solar Initiative databases provide the IOUs with much more detailed data on the exact location and size of anticipated wholesale and customer-sited DG systems than a forecast of EV locations. Thus, it appears that the utilities could utilize similar analyses for DG as an input in infrastructure planning.

A number of sources suggest ways this analysis can be accomplished and can inform the Commission's anticipated state planning process pilot. A recent paper co-authored by

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14 See Proposal Concerning Modification to LIPA's Tariff for Electric Service, pg. 4: http://www.lipower.org/pdfs/company/tariff/proposals-FIT070113.pdf.

15 Walking the Walk: Considering Non-Transmission Alternatives in Utility Planning, Part Deux, 2008 ACEEE Summer Study Proceedings Paper. "Geo-targeted energy efficiency and CHP projects continue to hold the promise to defer Southern Loop 46 kV transmission upgrades … Vermont's public preference for energy efficiency and small distributed resources, particularly renewable and sustainable generation units, may result in more non-transmission alternatives to further defer the Southern Loop upgrade." The paper describes screening tools and detailed benefit cost metrics available to assess EE as alternative to transmission upgrade investments. Available at: http://aceee.org/proceedings-paper/ss06/panel05/paper25.

16 ACEEE, *Coal retirements and the CHP Opportunity,* Anna Chittum and Terry Sullivan, September 2012, Report Number IE123.

17 A.10-11-015, Exhibit SCE-03, Volume 3, Part 2, at pp. 127-136.

Sandia National Laboratories and the Interstate Renewable Energy Council proposes an approach to proactive planning for growth in DG called Integrated Distribution Planning (IDP). IDP is based off of a variety of efforts being contemplated or implemented in utilities across the United States. These efforts look to proactively plan for DG growth and anticipate distribution system upgrades that may be necessary to accommodate both DG and load growth.[18] By combining interconnection and distribution planning, a utility can consider upgrades that can be shared between interconnecting projects, across any number of distribution feeders or a network, or between load and generation.[19] The result is distribution upgrade costs that can be spread more evenly among the parties that benefit, allowing the utilities to use DG to defer investments targeted at load.[20] Moreover, the upgrades can be planned more efficiently, where electrically related projects and load can share the cost of an upgrade that benefits both.[21]

Other states are beginning to implement proactive processes to take advantage of the interaction between DG growth and distribution planning. A collaborative stakeholder effort in Hawaii resulted in a unanimously supported "Proactive Approach" proposal to plan for high penetrations of DG.[22] A technical review committee analyzed the Proactive Approach and recommended it be adopted as a best practice.[23] In addition, New York's Commonwealth Edison has modified its distribution planning efforts to reflect the effects of certain combined heat and power plants.[24] Incorporating these DG resources into planning has deferred "multiple traditional T&D load-relief capital projects, realizing savings for the company and its customers."[25]

III. Conclusion

Vote Solar appreciates the opportunity to comment on the approach, findings, and next steps identified in the *Distributed Generation Integration Cost Study: Analytical Framework*. Studies of this type are critical to informing stakeholder discussions concerning the most cost-efficient means of achieving California's ambitious renewable

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18 Sandia National Laboratories and Interstate Renewable Energy Council, *Integrated Distribution Planning Concept Paper*, p. 6-10 (May 2013).

19 *Id.* at 13.

20 *Id.* at 13.

21 *Id.* at 13-14.

22 Hawaii Public Utilities Commission, *Reliability Standards Working Group Independent Facilitator's Submittal and Final Report*, Docket 2011-0206, Attachment 4, PV-DG Subgroup Summary of Proposal for Proactive Review Approach, (March 25, 2013). The Proactive Approach resembles and provided the inspiration for the Sandia-IREC IDP paper.

23 Hawaii Public Utilities Commission, *Report of the Technical Review Committee*, Docket 2011-0206, p. 40 (May 30, 2013).

24 M. Jolly, D. Logsdon, and C. Raup, *Capturing Distributed Benefits; Factoring customer-owned generation into forecasting, planning, and operations*, Public Utilities Fortnightly (August 2012).

25 *Id.*

energy goals. We look forward to future efforts to engage with stakeholders on these important topics and we are happy to address any questions raised by these comments.

Regards,

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