BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CAL

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
Application of Southern California Edison Company (U338E) for Approval of Its Distribution Resources Plan.	Application 15-07-002 (Filed July 1, 2015)
Application of San Diego Gas & Electric Company (U902E) For Approval of Distribution Resource Plan.	Application 15-07-003 (Filed July 1, 2015)
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005 (Filed July 1, 2015)
In the Matter of the Application of Pacific Gas and Electric Company for Adoption of its Electric Distribution Resources Plan Pursuant to Public Utilities Code Section 769 (U39E).	Application 15-07-006 (Filed July 1, 2015)
Application of Liberty Utilities (CalPeco Electric) LLC (U933E) for Approval of Its Distribution Resources Plan.	Application 15-07-007 (Filed July 1, 2015)
In the Matter of the Application of Golden State Water Company on Behalf of its Bear Valley Electric Service Division (U913E) for Approval of its Distribution Resource Plan.	Application 15-07-008 (Filed July 1, 2015)

VOTE SOLAR'S LOCATIONAL NET BENEFITS ANALYSIS PRE-WORKSHOP COMMENTS

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	Application No. 15-07-002 Application No. 15-07-003 Application No. 15-07-006 Application No. 15-07-005 Application No. 15-07-007 Application No. 15-07-008 (Filed July 1, 2015)

VOTE SOLAR'S LOCATIONAL NET BENEFITS PRE-WORKSHOP COMMENTS

In advance of the February 1, 2016 workshop on the Locational Net Benefits Analysis ("LNBA") proposed by Southern California Edison ("SCE"), San Diego Gas & Electric ("SDG&E"), and Pacific Gas & Electric Company ("PG&E") in the Distribution Resources Plan ("DRP") proceeding, Vote Solar respectfully submits the following comments.

Vote Solar is a non-profit, non-partisan, grassroots organization working to fight climate change and foster economic opportunity by bringing solar energy into the mainstream. In previous comments in this proceeding, Vote Solar has emphasized that the Commission should ensure that distribution planning strongly support a modernized electric grid which (1) serves as a backbone to facilitate access to Distributed Energy Resources ("DER"); (2) provides open access to DER providers; (3) facilitates information transparency and a greater diversity of energy choices for customers; (4) and expands options for renewable-energy procurement for all customers.

DISCUSSION

Vote Solar looks forward to participating in the upcoming LNBA workshop and to better understanding the IOU's proposed LNBA, methodologies and assumptions. As stated in previous comments, we believe the IOU's DRPs are somewhat consistent in the inclusion of various LNBA value components and use of the E-3 Distributed Energy Resource Avoided Cost ("DERAC") tool as directed by the Guidance Ruling[1], but are inconsistent in assumptions applied to the value components, are vague on the actual calculations, and lack examples of how each utility will actually apply the methodologies. This lack of clarity makes it difficult to evaluate the merits of the proposed LNBAs or to make specific recommendations for improving the analysis. For convenience, Vote Solar is attaching a table comparing the various IOU approaches to the LNBA, which was submitted in our earlier protest of the DRP applications.[2]

We agree with comments from many other parties that consistency in assumptions, LNBA methodology, and calculations across the IOUs is critical. Consistent approaches are easier for the Commission to evaluate and monitor, while providing clarity and certainty for customers and third party providers of DER. Since the LNBA will ultimately support development of DER tariffs or other payment mechanisms, consistency across the IOUs will lead to fairness in compensation, regardless of which service territory the DER is located.

The New York Public Service Commission recently issued its order establishing the Benefit Cost Analysis ("BCA") Framework for evaluating alternatives to traditional distribution

[1] Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution
[2] Vote Solar's Protest of Utility Applications for Approval of Distribution Resources Plans, August 31, 2015, Attachment A.

utility investment as part of the Reforming the Energy Vision proceeding[3]. The BCA Framework provides a detailed, consistent, transparent approach for all New York utilities to follow. The order requires utilities to submit BCA Handbooks detailing the benefit/cost components, assumptions and examples, and that "set forth common methodologies … for uniform application across the State to the extent feasible."[4] The BCA Framework also enables the assessment of portfolios of DER rather than just individual resources, "allowing for consideration of potential synergies and economies among measures"[5]. Vote Solar believes this emphasis on consistency and the ability to evaluate DER portfolios are important to include in this DRP proceeding.

Although not specifically addressed in the ALJ's Ruling Inviting LNBA Proposals, Vote Solar is very concerned about how the costs and performance characteristics for various forms of DER will be determined. Since the results of the LNBA could be negative or positive, the assumptions used for individual DER and/or combinations of DER are absolutely critical. Since the results of the LNBA may determine whether an IOU will invest in grid upgrades versus procurement of DER, Vote Solar believes the process for determining DER costs and performance characteristics should be independently evaluated and should include stakeholder input. As a possible alternative to a formal Commission proceeding, Vote Solar suggests forming an advisory group comprised of DER advocates or providers, environmental and consumer advocates, other interested stakeholders, Commission staff and IOUs. This group would be charged with determining whether adjustments to assumptions developed and approved in the formal DRP or successor proceeding are warranted. Further, since DER costs and

[3] See order from 1/21/16 available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101
[4] NY PSC BCA Framework Order at 31
[5] NY PSC BCA Framework Order at 2

performance characteristics are quickly evolving, we recommend that these values be reviewed at least annually, or in the context of a specific type of DER being considered as an alternative to an IOU proposed grid infrastructure upgrades, as part of that analysis.

Vote Solar also believes that more discussion and clarity is needed on how the IOUs will integrate the LNBAs with the proposed Integration Capacity Analysis ("ICA") results. The IOU's DRPs largely treat the two topics independently, and fail to explain how these frameworks will be integrated and incorporated into existing planning processes to accelerate DER deployment.

Vote Solar respectfully requests that, at minimum, the February 1, 2016 LNBA workshop discussions include the following topics:

- Explanation and examples of PG&E's formula for valuing deferral benefits and other elements of its LNBA calculation for all DER types (including energy efficiency and demand response) and for portfolios of DER
- Explanation and examples of SCE's Real Economic Carrying Charge methodology and other elements of its LNBA calculation for all DER types and for DER portfolios
- Explanation and examples of SDG&E's LNBA methodology and calculations for individual DER and for DER portfolios
- Explanations of how each IOU intends to use DERAC (or a modified version of DERAC) for all types of DER, including energy storage and electric vehicles
- Ways to achieve more consistency in LNBA assumptions, methodologies and calculations across the IOUs
- How each IOU intends to integrate the LNBA results with its ICA and to publicize the results for streamlining interconnection and for maximum transparency of optimal DER deployment locations

Commission staff has asked for comments on the DRP Roadmap staff proposal which categorizes certain LNBA components as either non-location-specific (i.e., ancillary services, avoided GHG adder, avoided RPS purchases, renewables integration adder) or location-specific (i.e., line losses, avoided T&D capital and O&M, voltage support, and power quality) and recommends that the non-location-specific components be reviewed in the Integrated Distributed Energy Resource ("IDER") proceeding, not the DRP proceeding. Vote Solar generally agrees with this approach. However, several parties have suggested modifications or additions to non-location-specific components for consideration in this DRP proceeding[6]. If the scope is divided as proposed, the Commission must assure that these suggestions are included and appropriately evaluated in the IDER proceeding.

Commission staff has also asked about the potential use of proprietary data and models in the LNBA. As stated in previous comments, Vote Solar strongly opposes the use of proprietary data and models. Transparency into utility's data, modeling and assumptions is absolutely vital to preventing overinvestment in the distribution grid, encouraging robust participation from third party DER providers, as well as extracting the greatest value from DER resources. Given the scope and complexity of the DRP, it is vital that third party providers be able to understand, test and replicate the IOUs' model results. To maintain the privacy of customer or sensitive IOU grid data, Vote Solar suggests creating an independent group of stakeholders to review and independently validate model results, similar to function of the Procurement Review Group, which is responsible for reviewing purchase power agreements. The group should consist of stakeholders who do not have a direct financial interest in the outcome of DER projects, with the assistance of modeling experts provided by the Commission.

Finally, Commission staff has asked what specific grid services (quantifiable or currently non- quantifiable) should the LNBA method include, as distinct from valuation methods that

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[6] For example, see Response of Bloom Energy, Inc. to DRPs, 8/31/15, pp. 3-5, and Protest of the Interstate Renewable Energy Council, Inc., 8/31/15, p. 28.

may be used in sourcing or procurement of grid services. Vote Solar agrees with the value components related to grid services outlined in the Guidance Ruling, and believes the full value of these DER grid services should be reflected in both the LNBA and future DER sourcing and procurement mechanisms. Vote Solar understands that the LNBA results may differ from actual tariffs or other compensation mechanisms used in DER sourcing since the tariffs will reflect dynamic measures of short-term benefits and costs. However, the value components used in the LNBA calculations and future tariff design should be the same. We also note that dynamic nature of grid conditions, loads and DER costs/performance requires regular updating and coordination between the value determination for the LNBA and compensation for DER sourcing. Vote Solar also agrees with NRG's characterization of the "triple value proposition" of DERs – customer value, value from distribution system services, and value from wholesale market services[7]. As the Commission and parties refine the LNBA methodologies and design DER sourcing/procurement mechanisms, it is important that customers and DER providers have the ability to earn full value from the multiple DER services provided.

[7] Response of NRG Energy, Inc. to the Distribution Resource Plans, 8/31/15, p. 5

CONCLUSION

Vote Solar appreciates the opportunity to submit these comments in advance of the LNBA workshop and looks forward to the February 1 discussion.

January 26, 2016

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ATTACHMENT A

Summary of Proposed Value Components in Locational Net Benefit Methodology (LNBM)/Optimal Location Benefit Analysis Calculations

Value Component	E3 DERAC	PG&E	SDG&E	SCE
Generation Energy	Forward market prices and the $/kWh operating costs of CCGT	PG&E would use an hourly profile of load increase or load decrease/generation levels specific to that DER or portfolio of DERs. PG&E proposes to use a model based on the energy price forecasting model developed for its 2015 Rate Design Window Application (A.14-11-014). This model uses public data from the CAISO and a forecast of system net load using public data to determine future energy prices.PG&E would also develop location-specific energy price adders to capture locational variation in energy price due to transmission congestion. These adders would be determined based on an analysis of historical Locational Marginal Prices (LMP) throughout PG&E's service territory.	SDG&E will use aggregated prices from SDG&E's single Default Load Aggregation Point (DLAP) as a proxy for generation energy value.	SCE proposes to calculate the Locational Marginal Prices (LMP) at the CAISO market's pricing node (Pnode) or aggregate pricing node (APnode) to which the contemplated DER corresponds. These LMP forecasts will then be used to calculate the energy value of DERs. SCE will also take into account whether the specific DER technology provides energy to the system and therefore warrants Generation Energy benefit as a part of its total locational benefits. Similarly, if DERs such as storage require energy to operate, the costs of this energy would also be included in the calculation.
Losses	System loss factors	PG&E proposes to develop a function that would estimate combined T&D losses at the line section level based on several easily estimated quantities, such as distance from substation and interconnection voltage level.In hours when a DER such as energy storage consumes energy, losses will increase energy and GHG costs. In hours when a DER such as energy efficiency reduces load, losses will decrease energy and GHG costs.For hours when a DER (e.g., DG) generates energy, PG&E would use an hourly model to determine the hours that the DER is resulting in backflow onto the transmission system. At these times, the DER-generated energy is not consumed locally and losses are not avoided. The combined T&D loss factor will be used to decrease energy and GHG costs in hours when a generating DER is not resulting in backflow onto the transmission system.	Due to the homogeneous nature of the SDG&E system, SDG&E intends to use its distribution system loss factor when computing potential decreased losses resulting from the installation of DER projects.	For resources interconnecting to the distribution system, SCE plans to use the distribution loss factor (DLF) appropriate for the interconnection voltage on the avoided energy.
Generation Capacity	Residual capacity value of a new CT	See *System or Local Area RA* value component	See *System or Local Area RA* value component	See *System or Local Area RA* value component
Ancillary Services	1% of generation energy value	1% of generation energy value	1% of generation energy value	SCE derives its ancillary services (AS) price forecast using a series of econometric and statistical models that capture current and future grid conditions, energy and fuel prices, customer demand and historical AS prices. The AS price forecasts also take the incremental flexibility need created by intermittent resources, through their expected build-out schedule and generation profiles, to inform increases in price levels and intraday volatility. SCE co-optimizes energy and AS value using fundamental production-cost simulation models. The difference between the energy-only value of the resource and the co-optimized energy and AS value is identified as the AS value of the resource. To the extent this value is not already reflected in the above described capacity value, it can be ascribed to the resource that is capable of providing the ancillary services.

Summary of Proposed Value Components in Locational Net Benefit Methodology (LNBM)/Optimal Location Benefit Analysis Calculations

Value Component	E3 DERAC	PG&E	SDG&E	SCE
T&D Capacity	Marginal T&D costs from utility GRCs	Difference between the deferral benefits (or accelerated costs) and the capacity-related costs for interconnecting DERs, less additional benefits of deferring or accelerating the project. (1) See formula at p. 70.	SDG&E will identify locations on either the distribution or transmission system where there is a need, and calculate a cost to install a traditional project to meet the identified need. The estimated cost will become the T&D Capacity value.	SCE recommends a new methodology to value T&D avoided costs in ($/kW) for DERs using the Real Economic Carrying Charge (RECC) method. The RECC method calculates the net present value of the capital investment deferral over an identified deferral time-frame. The potential capital investment to be deferred and the deferral timeframe are based on the amount of DERs that can reasonably be deployed to address the specified grid need, applied over the timeframe of the deferral, not a single year. This methodology values the benefit of investment deferral from customers' perspective and includes return on investment and utility taxes. Therefore, the methodology to calculate this valuation component includes the IOUs' planned project-specific deferral values and captures the geographical and temporal characteristics for each project. (2)
Environment	Synapse mid-level carbon forecast developed for use in IRPs	GHG is included in the Generation Energy component	SDG&E intends to utilize the CalEnviroScreen 2.018 to qualitatively analyze the impact of DER projects in lieu of traditional projects.	DERs will receive the value of avoiding GHG emissions via the value of avoided generation energy costs.
Avoided RPS	Cost of marginal renewable resource less the energy and capacity value associated with that resource	Once the RPS procurement impact (an increase or decrease) is determined, an RPS price premium is needed to translate that impact into an avoided or increased RPS cost. The RPS price premium is the difference between the RPS price and the capacity and energy value of the RPS resource. PG&E would use a proprietary RPS price forecast. Consistent with E3's DERAC tool, PG&E would apply the RPS premium to the quantity of avoided or increased RPS procurement to yield a DER's locational RPS impact.	SDG&E intends to use the default values from the DERAC tool in calculating this value.	SCE is planning to use the DERAC tool's methodology, but with SCE's values for the inputs (i.e., DERAC marginal cost of renewables less SCE's energy price forecast, ich includes the cost of GHG, less SCE's capacity price forecast) in the LNBM calculations. This calculation will provide an avoided RPS value which differentiates on location, in the spirit of the LNBM methodology.
Distribution Voltage	N/A	Same formula as T&D Capacity	SDG&E will identify locations where there is a system need, and calculate a cost to install a traditional project to meet the identified need. The estimated cost will become the Distribution Voltage value.	SCE will use the RECC method described above
Reliability and Resiliency	N/A	Same formula as T&D Capacity	SDG&E will identify locations where there is a system need, and calculate a cost to install a traditional project to meet the identified need. The estimated cost will become the Distribution Reliability and Resiliency value.	SCE will use the RECC method described above
System or Local Area RA	N/A	PG&E would determine the MW of avoided or increased system or local capacity associated with that DER using an Equivalent Load Carrying Capability (ELCC) methodology. PG&E plans to use a marginal ELCC RA value for DERs to recognize their incremental contribution to system reliability. PG&E plans to use an hourly, CAISO-wide Loss of Load Probability model to determine a DER's ELCC.	RA capacity credit will be assigned to DERs consistent with and contingent upon their demonstrated ability to meet the RA qualifying criteria as defined and continuously modified by both the CPUC and/or CAISO. In addition, the actual RA value for DER should reflect the current and forecasted resource adequacy situation e.g., the current and forecasted demand/supply balance in the load pocket. If the local area has more local resources than are needed, the local RA value should be based on market prices. If the local area is short of local resources, or forecasted to become short at some time in the future, then the value attributed to a DER solution capable of meeting RA eligibility criteria would be adjusted to reflect short conditions.	SCE will take into account available market prices for resource adequacy products, including price differentiation between local and system-level capacity, and also takes into account its portfolio requirement for certain type of resources in specific locations as well as the cost of new entrant capacity. In addition, SCE can ascribe value based on the attributes that the resource provides. For example, resources that provide local capacity, system capacity as well as flexible RA value75 would get a higher capacity valuation compared to resources that only provide system capacity benefits and are not flexible.

Summary of Proposed Value Components in Locational Net Benefit Methodology (LNBM)/Optimal Location Benefit Analysis Calculations

Value Component	E3 DERAC	PG&E	SDG&E	SCE
Flexible RA	N/A	PG&E would determine the MW of avoided or increased flexible capacity associated with that DER using an hourly model. This model would mimic the model that CAISO uses to determine the flexible RA requirement.	See above	See above
Renewable Integration Costs	N/A	For DERs which avoid RPS procurement—some of which comes from wind and solar resources—the cost of integrating that avoided RPS wind and solar is also avoided. PG&E would estimate the portion of a DER's avoided RPS that comes from wind and solar using its most recent public RPS procurement records. For DERs which are themselves standalone wind or solar resources (i.e., not shaped or firmed by storage), a renewable integration cost would be applied per megawatt-hour (MWh) of production from that DER resource to account for the utility's integration cost increase.	SDG&E will determine if the DER avoids any renewable integration costs. The DERs ability to reduce utility costs associated with renewable integration will be coordinated with the CPUC's efforts to update the RPS Calculator and the Renewables Integration Charge. It should also be noted that the DER could result in an increase in integration costs, in which it could receive a negative credit in this section.	Generally, SCE does not attribute the benefit of avoiding renewable integration cost with respect to any DERs that are interconnected behind the customer meter. Similarly, SCE does not attribute the benefit of avoiding renewable integration cost to any In-Front-of-the-Meter (IFOM) energy storage (ES), because to the extent IFOM ES avoids renewable integration costs, this benefit is captured in the form of avoided flexible RA and in the value of ancillary services provided.
Avoided Societal Costs	N/A	Not included	Societal benefits related to GHG reduction will be captured by using energy prices that fully reflect the GHG costs.	Not included
Safety	N/A	Not included	Not included	Not included

(1) - PG&E states that a benefit can occur only if all of the following four conditions hold: (a) there is an identified need to make distribution capacity expenditures; (b) DER capacity in the correct amount is certain to be available at the time of the relevant circuit or substation transformer peak (capacity need); (c) the DER is connected at the correct locations; and (d) the DER is controlled or managed to avoid any unavailability that could affect reliability or safety.

(2) - SCE states that the estimated transmission and distribution deferral value attributed to DERs will be based on the DER's load reduction capacity that is coincident with specific grid needs at specific locations on the distribution grid. For a portfolio of DERs that would be used to defer some planned grid project, the DER portfolio's load reduction capacity would thus be adjusted to reflect the likelihood that the DER will avoid the capital investment based on its characteristics and different locational scenarios. These adjustments would be based on a level of locational certainty, temporal certainty, the DER's peak coincidence to grid needs, and the ability to be dispatched to respond to the distribution system's needs, respectively. After these adjustments are made to the DER capacity, the T&D deferral valuation can be applied. Additional grid reinforcements may be necessary to balance load and demand where DERs create incidental issues that require mitigation, such as where ICA capacity is negatively impacted in the same area as where the load growth expansion is identified. In that case, the locational benefits must also consider the cost for other upgrades necessary to realize the capital deferral.