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 15-07-002 Application 15-07-003 Application 15-07-006

CLEAN COALITION POST WORKSHOP COMMENTS ON INTEGRATION CAPACITY ANALYSIS AND LOCATIONAL NET BENEFITS ANALYSIS METHODOLOGIES

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I. INTRODUCTION

Pursuant to the February 18, 2016, *Administrative Law Judge's Ruling Inviting Comments on Integration Capacity Analysis Methodologies, Integration Capacity Analysis Workshop Report, Locational Net Benefits Methodology, Locational Net Benefits Analysis Workshop and Demonstration Projects A and B* the Clean Coalition hereby submits these comments.

The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of distributed energy resources ("DER")—such as local renewables, advanced inverters, demand response, and energy storage—and we establish market mechanisms that realize the full potential of integrating these solutions. The Clean Coalition also collaborates with utilities and municipalities to create near-term deployment opportunities that prove the technical and financial viability of local renewables and other DER.

The Clean Coalition appreciates this opportunity to comment on the methodologies underpinning Distribution Resource Plans.

II. COMMENTS

Integration Capacity Analysis

During the Integration Capacity Analysis ("ICA") workshop, parties reminded the IOUs and the Commission of the need to incorporate the ICA into Rule 21. The DRP Guidance specifically described this goal:

An inevitable consequence of these rapidly evolving changes to utility distribution will be the need to add new infrastructure, enhance existing networks and adopt new analytical tools to allow consumers to be active managers of their electricity consumption through the adoption of DERs; the goal being to create a distribution grid that is "plug-and-play" for DERs. One integral step in this process is the need to dramatically streamline and simplify processes for interconnecting to the distribution grid to create a system where high penetrations of DER can be integrated seamlessly.[1] The Clean Coalition respectfully urges the Commission to elevate this significant issue going forward.

The ICA is a promising tool due to its potential to dynamically reflect distribution grid conditions—showing DER providers what level of resources the grid can accommodate in any given area. Rule 21's screens have proven useful, but the screens rely on conservative assumptions that do not provide complete and current grid information. For example, one Rule 21 screen requires that the peak capacity of distributed generation on a circuit cannot exceed 15% of the circuit's peak load without requiring completion of detailed engineering studies. This screen does not take into account the unique and changing circumstances of the grid at various locations, and leads to additional cost and delay for Supplemental Review. The ICA could dynamically provide updates on hosting capacity, including information on projects that have already entered the queue. Finally, the ICA should take into account the various operating

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[1] *Assigned Commissioner's Ruling On Guidance For Public Utilities Code Section 769 – Distribution Resource Planning* at 3, R.14-08-013 (Feb. 6, 2015).

capabilities of DER from the Commission's Rule 21 smart inverter decision.[2] If deployed properly, the IOUs ICA maps would uniquely improve the interconnection process and facilitate greater deployment of DER.

Utilities should include the interaction of various DER in ICA analysis as their ability to do so becomes available. This should be developed and trialed in the demonstration projects, and should build upon the analyses done by the Clean Coalition and others in improving CYME capabilities. This should include consideration of the Advanced Inverter functionality.

ICA modeling should include existing DER, and additional anticipated DER.

The ICA analysis performed looks for violation of any of four tests of operational limits. Because different limits will incur different costs to overcome (though operational mitigation of DER facilities [ex. limitation or dynamic curtailment of maximum load or generation] or upgrades to the distribution system), information regarding the nature of the violation limit discovered in testing is helpful to applicants and to Distribution Planning – clearly identifying and differentiating the low cost upgrades that would increase hosting capacity from those which are not cost effective. As practical, where the limit identified in ICA analysis is understood to be a relatively low cost upgrade, there would be significant value in continuing and testing to identify the degree of additional hosting capacity available until the next limit is reached.

Lastly, the Clean Coalition reiterates our recommendation that interconnection capacity information used in the maps be consistently made available in searchable database format to allow users to easily identify all locations meeting specified criteria.

Locational Net Benefits Assessment and Methods:

Distribution Marginal Value

The Clean Coalition recognizes and supports the opportunity for assessment of a distribution marginal value approach to provide detailed, accurate, and highly granular

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[2] *Interim Decision Adopting Revisions to Electric Tariff Rule 21 for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Require Smart Inverters*, D.14-12-035 (Dec. 14, 2014).

insight into location specific grid needs and opportunities to maximize both ratepayer and customer/provide value through targeted DER or other distribution investment and compensation for services or operation. This approach is expected to offer the most accurate location specific value assessment, and has indicated in application that location specific values frequently exceed average values by very wide margins. While the Clean Coalition is cautious regarding the use of proprietary methods, and has not definitively compared competing products available on the market, tools for such analysis, and the data necessary to utilize these tools, are available to the utilities, and the utilities have already gained some experience with their application. This work should be pursued in a public and coordinated fashion through this proceeding with the explicit goal of evaluating the potential application of these tools, vetting their current capabilities, and determining where valuation factors should be adjusted and different or additional value categories included, and the steps required to do so.

The data required to fully assess highly granular distribution value, and the effort to perform such assessments across each utilities distribution system, should be evaluated against the anticipated net ratepayer benefits such that application of these tools can be prioritized by area and degree of detail, accuracy, and comprehensiveness warranted by the anticipated results.

While we recommend pursuing this path, no conclusion can be reached until the methods and comprehensiveness of value categories have been vetted by parties, and the practical timelines determined for application across all or portions of the IOU systems. Average values and interim or alternate methods for establishing locational variation of value and can and should be utilized at what ever level of granularity is available until application of distribution marginal valuation approaches are practical and warranted. The Clean Coalition recommends adopting a pragmatic “best available data and methods” approach to advance Distribution Resource Plan data accuracy incrementally as methods can be employed and improved. We do not support delaying use of the best estimates of values available today in favor of better estimates in the future as this will necessarily reduce the aggregate realization of net ratepayer benefits, even if the individual instances are less accurate or reliable.

Joint Utility LNBA

The Clean Coalition is concerned that the Joint Utility proposed Locational Net Benefits Assessment ("LNBA") method only establishes a value based on deferred distribution upgrades, and a cost based on DER project procurement solicitation. Avoided or deferred upgrades are an important component in assessing the net benefits to ratepayers of the addition of DER capacity and services at locations where upgrades are otherwise anticipated, and is clearly helpful in determining when DER should be procured as alternative to specific upgrades. However, is not sufficient in-of-itself for that purpose, and is wholly in adequate in providing other proceedings with a location adjusted value of DER capacity or services by which tariffs or compensation levels might be established, or method for determining that value. Likewise, individual project solicitation is extremely cumbersome to employ, and may overstate the cost achieving the DER capacity or services needed to achieve specific upgrade deferrals. For example, DER assets owned by customers may already exist in aggregate within the locality sufficient to defer the planned upgrade if their operational characteristics are adjusted, and may be available at a least cost incentive, but are not candidates for participation in a utility solicitation process.

A Locational Net Benefits Assessment is intended to assess the net benefits of the facility, project, program, or scenario being considered. Net benefits are the total benefits less the total costs. Location specific net benefits would appropriately adjust net benefits analysis to reflect differences in value related to a location. Any methodology used to determine the LNBA must indicate a net total value, not merely the differential by which a location will increase or decrease the net value. For example, if the net benefit value of a generic capacity mitigation before considering location is 1.5, the value at a specific location will be 1.5 +/- a location adjustment; if that locational adjustment is +0.2, then the locational net benefit value would be 1.7. In this example, a $1,000,000 investment at that location would be seen as having a total gross value to ratepayers of $1,700,000, for a LNBA of $700,000, reflecting a $200,000 locational differential relative to a non-location specific net benefits assessment. If the LNBA is expressed as a heat map over a region, that map should indicate the base (average) net value and the locational differential.

To determine the LNBA, it is appropriate to start with an assessment of the average benefits associated with the capacity, service, or facility, and then consider how locational factors impact these default values. As illustrated below, these benefits occur at each layer of the electrical grid, and the total benefits accruing at each level above and below the point at which the DER is impacting the grid should be considered. Average values may be established system wide, or the average within any more granular definition by geography or characteristics that can be defined. For example, SCE defined 30 typical of distribution circuits, and values may be associated with each of these, adjusted in turn by locational factors.

System-wide Average Benefits
(Applicable to each layer)
HV Transmission (system wide)
LV Transmission (avg)
Sub-transmission (avg)
Distribution Planning Areas (avg)
Distribution substations (avg)
Circuits (avg)
Line sections (avg)
Local transformers (avg)
Metered Loads (avg)
BTM loads (avg)
Total:

Location Specific Benefit Value
(Applicable to each layer)
HV Transmission
Local LV Transmission Territory
Local Sub-transmission Area
Local Distribution Planning Area
Local Distribution substation
Local Circuit
Local Line section
Local transformer
Local Meter Load
local BTM load
Total:

When choosing an investment on behalf of ratepayers, the options should be compared as shown below, and those with the highest LNBA should be prioritized; however, each option offering any net benefits to ratepayers should be recognized as such.

Value Comparison		
Use default average value or location specific benefit as applicable for each layer (For example, a project connecting at a specific substation would apply individual values -if available- to all layers at or above that substation, and a locally averaged value to all layers below that substation)		
Project/proposal 1	**Project/proposal 2**	**Project/proposal 3**
HV Transmission	HV Transmission	HV Transmission
LV Transmission	LV Transmission	LV Transmission
Sub-transmission	Sub-transmission	Sub-transmission
Distribution Planning Area	Distribution Planning Area	Distribution Planning Area
Distribution substation	Distribution substation	Distribution substation
Circuit	Circuit	Circuit
Line section	Line section	Line section
Local transformer	Local transformer	Local transformer
Metered Load	Metered Load	Metered Load
BTM load	BTM load	BTM load
Total:	**Total:**	**Total:**

It must also be recognized that the net benefits vary by quantity as well as location, and the LNBA must expressly define that quantity. The first $1,000,000 in investment, or the first MW of capacity added will have a different value from subsequent investment. We emphasize however, that all investment, all additions of DER, will have some impact at all levels of the electric grid, net positive, net negative, or net zero. These impacts should be considered in aggregate not only for their role as an alternative to specific planned projects, but critically in their contribution toward either deferring or accelerating the need for grid investment and need for such projects.

For example, if in the absence of DER, peak load and congestion on the transmission system would require an average of 2% growth in transmission capacity per year, but if trajectory growth in DER without any change in ratepayer investment results in projected annualized growth in transmission capacity of 1% instead, then it should be recognized that default DER is reducing the need for additional transmission capacity by 50% - this is before any alternatives to specific transmission projects are even considered, because the need for additional transmission capacity has been reduced, deferring the circumstances under which transmission planning would indicate a need for project proposals to meet those needs.

We must be careful to avoid overestimating any such value, but a net benefits methodology must be equally careful to avoid failing to properly account for such value.

Understanding the net impact of greater or lesser growth in various DER is essential for effective development of policies, programs, tariffs, and compensation mechanisms through the IDER and other proceedings. Based on assessment of those net benefits, the outcome of these proceedings will determine the quantity and location of DER added to the system in future years, and the operational characteristics of both new and existing DER as owners respond to incentives and signals.

LBNA Savings Versus Investment

The joint utility LNBA approach considers where investment may be deferred to realize net ratepayer savings, but fails to capture where the ratepayer benefits of higher DER penetration will warrant distribution upgrade investments based on net benefits. In many cases, support for complimentary DER will realize the highest net benefits, such as coordinating EV charging with nearby PV generation to mitigate both load and variable generation impacts. LNBA should not only evaluate where complementary DER may avoid upgrades needed to accommodate customer demand and natural growth of DER, but also where upgrade investments may be warranted or most cost effective to support added DER. Because DER has impacts and potential value at multiple levels of the electrical grid, including system value, planning for net ratepayer benefits must consider this. Eventually, the grid may be modernized and support DERs everywhere; however, it is important to prioritize where to direct ratepayer investments in grid modernization and private investments in DERs. LNBA should indicate where upgrade investment should occur to support increased DER (organic growth or growth in response to incentives or procurement) because of the ratepayer value of the additional resulting DER relative to the cost of upgrades required to support it.

New York Benefit Costs Analysis Framework

Recent developments in New York's Reforming the Energy Vision ("NY REV") proceeding should inform the Commission's work on the LNBA. On January 21, 2016, the NY Public Service Commission ("PSC") issued the Order Establishing the Benefit Costs Analysis Framework ("BCA Framework"), which provides a foundation for DER valuation.[3] The BCA framework defines categories of benefits and costs that apply in four areas: (1) utility investments in distributed system platform capabilities; (2) procurement of DER through selective processes; (3) procurements of DER via tariffs; and (4) energy efficiency programs.

The PSC instructed the utilities to apply the BCA Framework whenever they propose to make investments that could instead be accomplished through DER alternatives. To measure the cost-effectiveness of DER alternatives, the BCA Framework adopted the Societal Cost Test ("SCT") as the primary valuation tool.[4] The SCT includes not only the value of deferred distribution upgrades contained in the utilities' currently proposed LNBA, but also a range of other values listed in the table below. Additionally, benefits directly related to the utility or grid operations that cannot be monetized must be reflected on a location- or project-specific basis when monetization is feasible at that level, and when monetization is impossible, non-energy benefits must be reflected qualitatively. While some of these value extend beyond ratepayer benefits, they are relevant to broader policy considerations and California's LNBA will have greater value if it is designed to be compatible with, and ideally able to integrate, these additional valuation factors.

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[3] N.Y. Pub. Serv. Comm'n, Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (Jan. 21, 2016).

[4] In addition to the Societal Cost Test, the PSC described that "[the Utility Cost Test and Rate Impact Measure] tests would be conducted, but would serve in a subsidiary role to the SCT test and would be performed only for the purpose of arriving at a preliminary assessment of the impact on utility costs and ratepayer bills of measures that pass the SCT analysis." *Id.* at 12.

Table 1: List of Benefit and Cost Components Included in the NY REV BCA Framework[5]

	BCA TEST PERSPECTIVE
BENEFITS	Societal (SCT)
Bulk System	
Avoided Generation Capacity (ICAP), including Reserve Margin	√
Avoided Energy (LBMP)	√
Avoided Transmission Capacity Infrastructure and related O&M	√
Avoided Transmission Losses	√
Avoided Ancillary Services (e.g. operating reserves, regulation, etc.)	√
Wholesale Market Price Impacts	--
Distribution System	
Avoided Distribution Capacity Infrastructure	√
Avoided O&M	√
Avoided Distribution Losses	√
Reliability / Resiliency	
Net Avoided Restoration Costs	√
Net Avoided Outage Costs	√
External	
Net Avoided Green House Gases	√
Net Avoided Criteria Air Pollutants	√
Avoided Water Impacts	√
Avoided Land Impacts	√
Net Non-Energy Benefits relate to utility or grid operations (e.g. avoided service terminations, avoided uncollectible bills, avoided noise and odor impacts, to the extent not already included above)	√
COSTS	
Program Administration Costs (including rebates, costs of market interventions, and measurement & verification Costs)	√
Added Ancillary Service Costs	√
Incremental Transmission & Distribution and DSP Costs (including incremental metering and communications)	√
Participant DER Cost (reduced by rebates, if included above)	√
Lost Utility Revenue	--
Shareholder Incentives	--
Net Non-Energy Costs (e.g. indoor emissions, noise disturbance)	√

Further, the BCA Framework does not leave the choice of when there are sufficient locational benefits to justify investment in DER solely in the hands of the utilities. Instead of just waiting for the utilities to identify deferred distribution upgrades, the BCA Framework will support the development of tariffs that place a value on DER.[6]

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[5] *Id.* at Appendix C.

[6] *Id.* at 4.

The PSC importantly recognized that "[t]he evaluation of tariffs, however, differs from the evaluation of utility system alternatives, because tariffs are more dynamic measures of near term benefits and costs."[7]

Although the BCA Framework itself is insufficient to fully value and monetize the benefits of DER, it will be used as essential guidance in designing replacement tariffs. That work will largely occur within the "value of D" process that the PSC has separately initiated within its Interim Ceilings Order. The "value of D" describes the full range of additional values provided by distribution-level resources. Through that effort, the PSC is designing a regulatory approach to valuing DER and designing compensation mechanisms and rates for DER providers. In the Interim Ceilings Order, the PSC further explained that "[the] 'value of D' can include load reduction, frequency regulation, reactive power, line loss avoidance, resilience and locational values as well as values not directly related to delivery service such as installed capacity and emission avoidance."8 The PSC issued Questions on the Value of Distributed Energy Resources and Options Related to Establishing an Interim Methodology, which establishes a process for parties to file proposals, respond to questions posed by the ALJ and in and subsequent discovery, and examine and comment on each other parties' proposals and assertions. 9 Initial proposals are due to the PSC on April 18, 2016.

Looking ahead in NY REV, the PSC instructed the utilities to develop BCA Handbooks that will guide DER providers in structuring their proposals for DER alternatives. The BCA Handbooks are to be developed in coordination with the utilities' Distribution System Implementation Plans ("DSIPs"), which are similar to the DRPs and will describe system needs, proposed projects, potential capital budgets, and plans to solicit DER alternatives. The utilities in New York must file proposed BCA Handbooks with their DSIPs on June 30, 2016. The Clean Coalition recommends that a similar approach be adopted in California to inform DER providers and market participants

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[7] *Id.* at 4.

[8] N.Y. Pub. Serv. Comm'n, Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation at 9 (Oct. 16, 2015).

[9] N.Y. Pub. Serv. Comm'n, Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference (Dec. 23, 2015).

where, when and how utilities will be seeking additional DER, including an indication of the scale and value of associated capacity and services.

Transmission Capacity

As noted above, net benefits associated with DER occur at all levels of the electrical system and must be accounted for when assessing the net benefits that will result from the addition of DER at any specific location.

Reduced demand on transmission will reduce or defer the need for additional investment to expand transmission capacity. Transmission capacity has value not only wherever it can relieve congestion today but also where demand is anticipated to exceed supply within the lifespan of existing facilities. While LNBA should reflect location specific contributions to individual project deferral where applicable, it is essential to recognize that a MW of coincident peak load served locally avoids utilizing a MW of existing transmission capacity, making that capacity available to deliver other resources and deferring the overall need for future capacity additions throughout any upstream portion of the system that would be expected to experience growth, eventually exceeding current capacity. As such, any LBNA methodology should account for the average regional or Local Capacity Area value of transmission capacity when not associated with a contribution to specific project.

Transmission costs vary widely between projects, but if an average figure of $1 Million is used as the marginal cost per Megawatt of new transmission capacity, based on approved or completed transmission projects in California since 2009, the savings are seen to accrue rapidly, as discussed in prior testimony[10]. While existing transmission will still be broadly utilized to supply energy during hours in which local intermittent DER is not available, even intermittent DER can offset new transmission capacity required for peak annual transmission loads up to the full rated capacity of the DER.

With approximately $20 Billion in currently planned future investments for roughly 20 GW of new capacity, 1 GW of aggregated avoided new transmission capacity resulting from procurement of DER represents a 5% reduction in the basis for future

[10] Clean Coalition Rebuttal Testimony Regarding PG&E and SDG&E Applications to Establish Green Tariff Shared Renewables Programs, A.12-01-008 and A.12-04-020; January 10, 2014.

Transmission Revenue Requirements, or 0.005% per fully qualifying MW. Taking a levelized 20 year value, this results in a savings of 0.0012¢/kWh. This appears a very small number, but this savings would be realized by virtually all of the 254,000 GWh[11] consumed within CAISO transmission system electricity by 2020. These cost savings would equal $30,540 in annual CAISO wide ratepayer savings today for each MW reduction in required transmission capacity, assuming a 1:1 peak annual capacity reduction. Applied to a DG PV output of 1,500 MWh/MW/yr, this results in an added ratepayer value of 2¢/kWh. While the applicable transmission capacity reduction will depend on CAISO projected relationship between the generation and peak demand profiles, the value of avoided future transmission capacity cost is too large to ignore.

As part of the Hunters Point Project Analysis,[12] the Clean Coalition found that over the course of 20 years, each additional MW of local distributed generation will avoid $236,700 in line losses, and an average of $610,000 in new transmission capacity costs.

Lastly, we take this opportunity to remind parties that Transmission Access Charges (TAC) are currently applied to the gross metered load of IOU customers, including energy produced by distributed generation resources and delivered to local customers, even though this generation does not rely upon the transmission system for delivery and, as noted above, can free up transmission capacity for other resources and reduce the need for new transmission investment. This matter is scoped for possible consideration in the CAISO ESDER Phase II stakeholder process. If the TAC tariff is amended to assess charges based on the utilities gross load as measured at the transmission-distribution interface instead of at the customer meter, utilities will avoid this charge on energy produced and consumed within each distribution substation area. This charge is an extremely significant value the would be applicable to DER in most locations and would very substantially change the LBNA results if amended. The value, specific to each utility, currently stands at 1.7¢ per kWh for PG&E (2.8¢ levelized for a

[11] California Energy Demand 2012-2022 Final Forecast Volume 1: Statewide Electricity Demand and Methods, Mid Energy Demand

[12] The Clean Coalition's Hunters Point Project Benefits Analysis is available at http://www.clean-coalition.org/site/wp-content/uploads/2013/12/HPP-Benefits-Analysis-19_jb-20-Dec-2013.pdf.

20 year investment), and has grown rapidly as new transmission capacity has been required. To the extent that DER can be employed to reduce the need for new transmission, the TAC rate will be lower for all ratepayers and all resources.

III. CONCLUSION

The Clean Coalition appreciates this opportunity to offer comments on ICA and LBNA issues in this proceeding and supports the Commission's continued work on the development of Distribution Resource Plans.

Respectfully submitted,

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