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
(NOT CONSOLIDATED)	
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)
And Related Matters.	Application 15-07-007 Application 15-07-008

CLEAN COALITION COMMENTS ON THE INTEGRATION CAPACITY ANALYSIS AND LOCATIONAL NET BENEFITS ANALYSIS FINAL SHORT-TERM WORKING GROUP REPORTS

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I. INTRODUCTION

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), the Clean Coalition respectfully submits these comments on *Assigned Commissioner's Ruling Requesting Comments on the Integration Capacity Analysis And Locational Net Benefits Analysis Final Short-Term Working Group Reports* ("ACR"), dated April 19, 2017.

The Clean Coalition has been an active and consistent participant in both the ICA and LNBA working groups and an original advocate for distribution resource planning and processes. We commend the diligent efforts of working group members in addressing a large number of issues and reaching consensus to the full extent possible within the adjusted timeframe, and we duly appreciate the work of Commission staff in reviewing and responding to the working group's reports and recommendations. We broadly concur with and support the consensus conclusions of the Final Short-Term Working Group Reports ("Report") and offer the following responses to specific questions raised in the ACR.

II. Description of the Party

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.

III. Comments

A. Integration Capacity Analysis

1. *Did the IOUs adequately execute Demonstration Project A according to the requirements of the May 2 and August 23 ACRs?*

We believe the Demonstration projects were properly executed to the fullest extent possible within the timeframe and should be considered to have met the requirements. The Working Group engaged with the IOUs and reached consensus on refinements for the demonstrations and subsequent work, as described in the Reports.

2. *Is the Demo A methodology able to achieve the two ICA use cases defined in the ICA Report: Interconnection Streamlining/Online Maps and Distribution Planning?*

Demo A reflects major advances in the ICA methodologies toward achieving both the planning and interconnection streamlining use cases. However, it should be recognized that Demo A tested the capabilities achievable at the time in a context of rapid development among both the utilities and the software providers they rely upon. While the methods employed for Demo A were very much a snapshot of work in progress, with the refinements identified in the Working Group Report, the iterative methodology should be considered able to achieve the Interconnection Use Case, and the streamlined or a hybrid methodology can meet the Planning Use Case goals.

The iterative methodology may also be able to meet planning use case needs if sufficient computational efficiency is realized in application. However, the evaluation of multiple alternate planning scenarios and refinements will be constrained by the greater data processing requirements and run times of this approach, compared to the streamlined approach developed by PG&E. The planning use case requires further definition and development to determine whether this constraint will substantially limit the functionality of the iterative use case for planning purposes.

The Clean Coalition sees very substantial merit in the opportunity to evaluate a potentially large number of planning scenarios in which different combinations of rate design, tariffs, or other compensation mechanisms or location-specific incentives are evaluated in relation to DRP grid modernization investment, Integrated Resource Planning and Long Term Procurement, and the Integrated Distributed Energy Resource proceeding, among others.

By way on comparison, the PLEXOS model employed by CAISO and used in the Long Term Planning & Procurement proceeding has historically been so time intensive to employ that it has been impractical to consider more than four or five scenario variations, inhibiting the consideration of promising and potentially significant planning alternatives. While the challenges with PLEXOS arise more from input labor and the ICA constraints are associated more with data processing time, the effective impact on planning use cases is similar.

3. *For Interconnection use case:*

   a. *Do you support the primary Working Group recommendation to use iterative methodology for online maps and interconnection purposes, or PG&E's proposal to display streamlined results on maps and use iterative methodology on a case-by-case basis? Explain.*

The Clean Coalition strongly supports the primary Working Group recommendation to use iterative methodology for online maps and interconnection purposes. While PG&E's approach may be best for planning purposes and represented a state of the art breakthrough in the 2015 DRP, it is clear that the results lack sufficient engineering reliability for direct application to a streamlined interconnection review process. It is essential that the ICA results accessed by users through the map or database provide information that applicants can count on before investing in project design and interconnection application requirements. Likewise, truly streamlining the interconnection review process should generally be understood to avoid backlogs and delays, such as those related to conducting a new power-flow study before approving an interconnection request that already conforms to the published ICA values for that location.

As we move toward more streamlined and efficient interconnection practices and reducing the excessive soft costs impacting project development, ratepayer costs, and customer options, the goal should continue to be toward both deterministic and reliable pre-application information such that:

(a) DER projects can be designed correctly to fit grid capacities before being reviewed by the distribution operator, and

(b) Automated processes can provide consistent and even near instantaneous review, in accord with the "plug and play" outcome defined in the DRP Guidance.

In theory, PG&E may someday be able to produce outcomes nearly comparable or even superior to the iterative approach through access to on-demand, real-time, automated power-flow analysis of individual locations via the ICA map web interface. However, this is a speculative proposition; it should not influence the necessary Decision at this time, but is worthy of further consideration and pursuit.

b. *For iterative methodology, discuss your preference for the following update frequency and hourly profile options, given the cost estimates provided by the IOUs and other factors:*

    i. *Monthly v. weekly updates for circuits with changed conditions (e.g., new DER interconnections or system upgrades);*

We recommend the Commission initially adopt an update schedule of "at least once a month" and require each distribution operator to pursue cost-effective opportunities for more frequent updates.

The value of ICA data for interconnection is in its timely and reliable application to interconnection requests. As such, changes that warrant updating ICA values will result in the published values being rendered stale and delay applicants ability to make use of the data, contrary to the goal of streamlining the process.

The initial cost estimates for providing either monthly or weekly updates were not vetted in detail by the Working Group, and the basis upon which the difference is estimated is unclear. The Clean Coalition and others have emphasized that, because the ICA is calculated independently within each distribution substation, updated values are only required in those locations within which changes have occurred. As such, it appears to the Clean Coalition that a monthly update would entail roughly the same total number of circuit updates as the aggregate of four weekly updates, especially if de minimis changes were only considered on a monthly basis if at all. This strongly suggests that weekly updates would not actually result in significant cost increases. This issue was raised by the Working Group in response to the initial estimates, but no firm conclusion was reached. Due to the small percentage of circuits anticipated to have ICA values impacted by changes each month, the additional cost of more frequent updates would not be warranted if this did in fact represent a doubling in costs as reflected in the initial estimates included in the Report.[1] However, that conclusion is unreliable and demands review.

In addition, it is essential that the ICA information clear indicate when published ICA data becomes outdated and no longer reliable for its planned use case in review of interconnection applications. Ideally, the ICA maps would indicate circuits flagged for review, but notification may also occur in a supplemental sheet that is updated more frequently.

Ideally, ICA values would be automatically refreshed whenever a new interconnection enters the queue, or whenever a utility upgrade or reconfiguration is scheduled. In this way, when new information is received and entered into the databases influencing ICA results, the software would recalculate the value to reflect circumstances relevant to an interconnection request, without the staff hours or delays associated with manually determining when and where a refresh is required. It is not essential to implement all features immediately, but the goals should be kept in mind and implemented as soon as practical.

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[1] Table 1: 'Cost Estimates Comparison of Multiple ICA Implementation Scenarios', Integration Capacity Analysis Working Group Final Report.

ii. *576 v. 96 hourly profiles (one min/max day each month v. two representative min/max days per year)*

The Clean Coalition supports the use of a 576 hourly profile. The 96 hour profile is incapable of indicating seasonal variation throughout the year and accurately portraying the degree to which the minimum and maximum values reflect more typical or outlier results across all months.

The value of hourly profiles is in the ability to assess the potential need to either reduce the project size or occasionally curtail its load or generation profile in order to optimize use of existing grid capacity and avoid the need for additional grid investments that would rarely be utilized. A 576 hour profile, providing representative information for each month of the year, is far superior in achieving this goal. Although still a compromise that may be mitigated with additional data, access to the 576 profile prior to filing a separate data request or Pre-Application Report will reduce the staff burden and delays for both the distribution operator and applicant.

Given the greater value, the Commission must weigh the cost differential. The Working Group was able to obtain cost comparison estimates from each IOU, which were included in the Report. While we very much appreciate receiving these estimates, the Working Group was not able to evaluate their basis and accuracy, and substantial questions remain regarding the basis for assumptions of differences in costs between the 96 hour and 576 hour estimates. To the extent that the difference would be primarily driven by additional computer processing time rather than additional staff time or other fixed or variable costs, we strongly question the proposition that running six times the number of calculations will substantially impact overall ICA costs.

We note that the difference in estimated cost between the two options is well within the range of variability estimated for either option, so we should not rely to heavily on direct comparison. PG&E estimates suggest a 40-50% cost difference the first year, while SCE and SDG&E estimates are within 10%; ongoing costs are more consistently within a 30-50% difference range. However, percentages must be taken in context, and even if we take the highest costs estimated by any utility, the difference is within $1.5 Million per year. This is hardly insignificant, but represents $30 spread across each of 50,000 annual interconnection requests, and commensurate savings in staff time alone may outweigh this.

As we evaluate Track 3 Grid Modernization investment in the context of several billion dollars of annual expenditure on distribution system upgrades and maintenance, the annual cost of ICA represents roughly 0.000015% of these costs, and provides a state of the art foundation for optimization in exchange. On this basis we find the potential cost differential for 576 hour analysis to be well warranted.

4. *Is the proposed 12-month implementation schedule and Tier 1 Advice Letter process for requesting non-substantive schedule or methodology refinements and implementing long-term refinements during the course of initial system-wide rollout reasonable? How should IOUs be required to confer with Working Group members before submitting modification requests?*

The proposed 12-month implementation schedule is a reasonable maximum allowable time and will support a clear deadline for incorporation of interim refinements.

System-wide implementation of the ICA would produce substantial value immediately, and delays in initial implementation will result in significant loss in realizing this value during any delay. For this reason, implementation should occur as early as possible, as generally recommended by the Working Group, and enforced by a "no later than" required date for implementation. The IOUs have indicated that implementation of the planned methodology across all circuits may require up to twelve months from the date of Commission Order. While Working Group participants have broadly sought more rapid implementation and hope it will be achieved, it is generally acknowledged that requiring faster implementation is not practical. The Clean Coalition supports this schedule.

All methodological refinements should be reviewed by the Working Group as long as it is active, and the Working Group's response should be reported in conjunction with an Advice Letter.

5. *Should the Commission adopt interim IOU reporting requirements for the initial system-wide rollout? If so, what types of data, milestones, or other information should the IOUs report on?*

Each IOU will necessarily develop an internal schedule in order to meet compliance deadlines. It is reasonable and appropriate for each IOU to share a milestone schedule summary with the Commission and Working Group within no more than 60 days following Commission Decision. Subsequently, each IOU should report any changes in dates for achieving interim steps and whether these are anticipated to impact the content or date of initial system wide implementation, and seek guidance from the Commission and Working Group. In the absence of any reported changes, the IOUs should be considered to be "on schedule."

6. *Should the Commission direct the IOUs to demonstrate, before ordering system-wide implementation, the automated process for identifying and evaluating feeders for pre-existing conditions and whether the ICA value is zero or non-zero depending on if DERs improve or degrade the pre- existing condition? Or, could the IOUs develop such a process during the implementation period and discuss it in an interim report?*

As noted above, system-wide implementation of the ICA will produce substantial value, and delays in implementation will result in significant loss of this value during any delay. For this reason, system-wide implementation should occur as early as possible. Enhancements to the ICA related to identification and analysis of pre-existing conditions should be implemented at the earliest practical opportunity, and should both incorporate the maximum refinement achievable within that time, and continue with further refinements as they become available. These refinements are unquestionably important and must be addressed, but should not delay overall implementation and access to ICA results for all other locations. Such refinements should be reviewed by the Working Group as long as it is active, and discussed in an interim report or an update report after initial system wide implementation has occurred.

7. *The report documents a "red" ORA metric of success regarding the loss of circuit model tweaks required for convergence upon incorporating new GIS or other data sources into the power flow circuit model. Should the Commission direct the IOUs to demonstrate, before ordering system-wide implementation, how they will maintain network model accuracy in the course of regular updates? Or, could the IOUs develop such a process during the implementation period and discuss it in an interim report?*

In deference to the principle that we should not allow a search for perfection to become the enemy of the good, the enhancements to the ICA should be implemented at the earliest practical opportunity and should both incorporate the maximum refinement achievable within that time, as well as continue with further refinements as they become available. Such refinements should be reviewed by the Working Group as long as it is active, and discussed in an interim report or an update report after system-wide implementation.

As noted above, the value of system-wide implementation of the ICA is substantial and delays in implementation will result in significant loss during any delay. The proposed 12-month implementation schedule is a reasonable maximum allowable time and will support a clear deadline for incorporation of interim refinements. The Clean Coalition prefers expedited implementation but supports this schedule.

We believe that this will allow sufficient time to also address the issue of incorporating updated GIS or other data sets into the model while retaining interim model corrections. The concern is not that the resulting model will contain errors, but that the processes for retaining or reintroducing corrections is not yet automated and therefore labor intensive. The issue is not conceptually complex but will require skilled implementation. There is no reason to believe that each IOU will not make good faith efforts to address this and avoid unnecessary model maintenance costs. However, we recommend that this issue be reviewed within the cost recovery process.

B. Locational Net Benefits Analysis

1. *Did the IOUs adequately execute Demonstration Project B according to the requirements of the May 2 and August 23 ACRs?*

Yes, the Working Group reached consensus that IOU Demo B implementations are fully compliant all requirements set forth in the May 2nd and August 19th Assigned Commissioners Rulings.

2. *Is the Demo B methodology able to achieve the two LNBA use cases described in the Report: 1) Public Tool/Heat Map and 2) Prioritizing Candidate Deferral Projects?*

The Demo B methodology did create a Public Tool and Heat Map with reasonable and appropriate initial functionality, although, as identified in the Report, further refinement to the input values is warranted for this tool. Refinement is needed in both the foundational average values established in DERAC, and the location specific variation from average values.

The Clean Coalition respectfully urges the Commission to adopt base values for transmission and other categories not already established within the DERAC model, as well as taking steps to address more comprehensive alternatives to the existing Avoided Cost Methodology in coordination with the Integrated Distributed Energy Resources

(IDER) proceeding. DER result in transmission savings to ratepayers, but these avoided costs are not currently considered in the DERAC model. For example, rooftop proliferation has contributed to the cancellation of multiple planned transmission projects in California, saving ratepayers hundreds of millions of dollars in avoided transmission investment.[2] Beyond anecdotal examples, DER deliver energy to customers without using the transmission grid, thereby making transmission capacity available that would have otherwise been used. This delays or avoids the need for additional transmission investment, to the benefit of ratepayers. These costs are not, but should be included in the DERAC model.

While the Public Tool methodology is functional and provides indicative values for many benefit categories, the IOUs have stated that they will rely upon proprietary methods and values in prioritizing candidate deferral projects, and proceeded to do so for the IDER Incentive Pilot in which distribution upgrade projects were ranked and selected for DER alternative solicitations. Because the benefits and DER capabilities beyond specific avoided or deferred distribution upgrades are not being solicited by the IOUs in that pilot, the additional benefits reflected in the LNBA may not be considered, and suppliers will be required to seek separate markets or compensation compatible with the solicitation performance contract. Additional steps are required by the Commission in the IDER and other proceedings to establish rates, tariffs, and other compensation mechanisms reflecting DER locational benefits in accord with the LNBA tool, and to ensure coordination, provision, and optimal dispatch of DER resources and functions, such as through a Distribution System Operator.

3. *Elaborate on the Working Group recommendation that the Demo B methodology is not ready for system-wide implementation for these two use cases until the Deferral Framework is adopted, given the recommendation that the Demo B methodology is adequate for provisional use in the IDER Incentives Pilot, Demo C, and the Deferral Framework.*

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[2] See Sheehan, Tim. "Solar growth puts Fresno high-voltage line on hold." *Fresno Bee,* 20 Dec. 2016, *available at* http://www.fresnobee.com/news/local/article122063189.html. *See also* Pyper, Julia. "Californians just saved $192 million thanks to Efficiency and Rooftop Solar." *Greentech Media*, 31 May 2016, *available at https://www.greentechmedia.com/articles/read/Californians-Just-Saved-192-Million-Thanks-to-Efficiency-and-Rooftop-Solar.*

As noted in the Working Group Report, the current LNBA tool addresses the narrow question of evaluating DERs in single locations against certain distribution upgrades that are already in IOU distribution system plans, and does not offer a comprehensive, location-specific utility avoided cost calculator that could be used to proactively identify high-value locations for DER deployment or develop rates, tariffs, or other compensation mechanisms.

4. *Implementation Questions (especially for IOUs):*
   c. *Which values, tool/heat map improvements, and other long-term refinements could be seamlessly integrated into the tool and heat map after system-wide implementation? Or, is it necessary to finalize long-term refinements before implementing the tool and heat map system-side?*

It is not necessary to finalize long-term refinements before implementing the tool and heat map system-wide. Placeholder values for existing value categories can easily allow for updates as data becomes available. Placeholder categories for additional values can also be reserved within the established methodology, however implementation will require updates to the formulae used to express these values within the adopted method.

5. *Provide feedback on the CPUC memo describing a future LNBA use case to develop locational T&D inputs for use in cost-effectiveness evaluations and DER sourcing activities. How must the tool evolve from a modeling or methodological standpoint in order to achieve this use case?*

As noted in the February 1st Commission Memo, a number of other proceedings are looking to the LNBA to develop location-specific avoided cost values for use in various cost-effectiveness studies to indicate high-value locations for distributed energy resource (DER) deployment, inform resource procurement decisions, and develop rates or tariffs for sourcing DERs. AB 327 added § 769 to the Public Utilities Code explicitly requiring each electrical corporation to develop a DRP, including a proposal to identify optimal locations for the deployment of distributed resources.[3] Identifying and quantifying locational variation in value for the optimal incentivization and development of distributed resources

[3] California Pub. Util. Code § 769(b) requires each electrical corporation to "(1) Evaluate locational benefits and costs of distributed resources located on the distribution system. (2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives. (3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources."

is a core purpose of the DRP and a legislative requirement. Analysis of the avoided distribution infrastructure costs based on the location of DER is central to the DRPs, which must be able to go beyond the current DERAC cost-effectiveness protocols.[4]

In compliance with § 769, the Commission, IOUs and others must work to revise existing incentives and tariffs to promote DER in locations that will provide the greatest net benefits to the grid,[5] and the ACR requires an Optimal Location Benefits Analysis to specify the net benefit that DERs can provide in a given location.[6] The LNBA is explicitly intended for development of "Distributed Energy Resource Development Zones" in Phase 2 of the DRP starting in 2018, including DER procurement policy and Distribution System Markets that can support grid service transactions, in addition to distribution infrastructure planning.[7] The method for assessment of locational benefits that accrue to the customers and/or the utility should be based on considerations of how to flow locational benefits through to customers, either in terms of rates, incentives, or other mechanisms.[8]

In light of the statutory requirements and related Commission rulings, the February 1st Commission Memo properly describes essential LNBA use cases to develop locational transmission and distribution inputs for use in cost-effectiveness evaluations and DER sourcing activities.

In application, the tool should provide the foundation for development of rates and tariffs for DER compensation reflecting locational differences in value. While a "heat map" representation of differential value provides guidance in identifying locations related to value categories, this guidance is only meaningful and effective if it is associated with rates and tariffs through which the higher value can be shared between ratepayers and those supplying DER functions.

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[4] *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769– Distribution Resource Planning* (Feb. 6, 2015), Attachment: Guidance for Section 769 – Distribution Resource Planning at 16.

[5] *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769– Distribution Resource Planning* (Feb. 6, 2015) at 4.

[6] *Id.* Attachment at 4.

[7] *Id.* at 12-13.

[8] *Id.* at 15.

The LNBA Public Tool is methodologically effective in capturing defined utility needs at identified locations and supporting input of user-defined DER profiles in relation to both those specific needs and to the potential generic value of DER functions (including energy and services). However, the resulting values are merely indicative until they are reflected in actual compensation mechanisms.

In order to meet the requirement to identify optimal locations, the LNBA heat map and associated Public Tool require input from planning forecasts beyond the scope of individual project planning and associated solicitations, as discussed in detail in the Working Group's LNBA long-term development report and associated comments. The methodologies for calculating benefits are well established, but many of the necessary input values to perform those calculations have not yet been adopted.

The Clean Coalition reiterates and emphasizes the importance and urgency of adopting initial estimated values without delay, and then continuing to refine the accuracy of those estimates as additional information becomes available. Failure to incorporate a value is necessarily an error in valuation, and adoption of either consistently conservative or generous estimates will bias results and undermine any "least regrets" analysis.

For example, the DERAC model (from which LNBA draws many initial values before adjusting for locational variation) allows users to establish avoided transmission without incorporating a default value. LNBA interprets this null value as zero. It is acknowledged by all parties that the actual value is not zero, that in most cases the value is positive, and that it will vary by DER performance profile and by congestion, deliverability, and other factors associated with the region, area, or precise location. An average or typical value will better capture actual value than a null entry, and any degree refinement beyond system wide average will contribute to identifying relatively optimal locations. It is important to improve the granularity of values wherever there are significant differences, and existing analyses such as those of Distribution Marginal Costs demonstrate great variability as granularity is refined. However, LNBA should not be restricted to reflecting locational variation in value only within the distribution system. For both planning and policy purposes—especially location specific rates and tariffs—regional variation in values at the substation, sub-transmission, and transmission levels, including both low voltage and high voltage, must be captured and incorporated.

Additionally, marginal deferral value must be recognized. For example, where a 4 MW capacity need is forecast in 4 years based on a relatively constant growth in demand, the addition of 1 MW of DER-based load mitigation per year will continually defer the 4 MW capacity upgrade, and each MW of DER should be recognized for the value of a one year deferral, even though not sufficient to remove the capacity project from future planning process.

Crucially, the LNBA heat map and tool must reflect not only the geographic variation in value but also the scale of that value, and the change in value as the supply is increased and demand is met. This is captured when reflecting individual planned distribution investment project deferrals, but supply/value curves over broader areas will be essential in the development of rates and tariffs, and more generally for Integrated Resource Planning.

Lastly, in both IRP and the development of potential solicitation or compensation mechanisms, it will be important to consider not only the locational benefit value of DER, but also the availability and cost of resources. While it is beyond the scope of the LNBA to incorporate these, consideration and coordination should occur to support data and heat map compatibility with other relevant inputs. For example, the potential to overlay and integrate ICA capacity and renewable resource potential against LNBA value will help determine the degree to which DER can be expected cost effectively supply areas of high locational value. Use of consistent or compatible data and mapping formats is recommended.

IV. CONCLUSION

The Clean Coalition appreciates the opportunity to submit comments on the ICA and LNBA Working Group Final Short-Term Reports, and supports the Commission's continued efforts in the Distribution Resources Plans proceeding to realize the benefits of DER for ratepayers at large, individual customers, and communities.

Respectfully submitted,

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