Decision 17-09-026 September 28, 2017

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
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
And Related Matters.	Application 15-07-007 Application 15-07-008

DECISION ON TRACK 1 DEMONSTRATION PROJECTS A (INTEGRATION CAPACITY ANALYSIS) AND B (LOCATIONAL NET BENEFITS ANALYSIS)

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DECISION ON TRACK 1 DEMONSTRATION PROJECTS A (INTEGRATION CAPACITY ANALYSIS) AND B (LOCATIONAL NET BENEFITS ANALYSIS)

Summary

The Commission opened this proceeding in response to the Legislature's directive that Investor-owned Utilities (IOUs) prepare, and submit to the Commission for approval, Distribution Resource Plans that identify optimal locations for the deployment of distributed energy resources (DERs). Given the complexity and plethora of issues facing the Commission, this proceeding was divided into Three Tracks, with Track 1 focused on the methodological issues known as Integration Capacity Analysis (ICA) and Locational Net Benefit Analysis (LNBA), and the authorization for Demonstration Projects A and B that are associated with researching and improving those methodologies. In response to the Assigned Commissioner's Rulings of May 2, 2016 and August 23, 2016, the IOUs met and conferred amongst themselves and with interested stakeholders, filed their Demonstration Projects A and B reports in December 2016,[1] and filed their two Working Group Final Reports on March 8, 2017 (LNBA) and March 15, 2017 (ICA).

This decision addresses Track 1 (methodological issues) for Demonstration Project A (ICA) and B (LNBA). Having reviewed these two Working Group Final Reports as well as party comments, the Commission rules on the issues presented in the Working Group Reports as follows:

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[1] Pacific Gas and Electric Company filed its *Demonstration Projects A and B Final Reports* on December 27, 2016; San Diego Gas and Electric Company filed its *Demonstration Projects A & B Final Reports* on December 22, 2016; and Southern California Edison Company filed its *Demonstration Projects A and B Final Reports* on December 23, 2016, followed by its *Updated Demonstration Projects A and B Final Reports* on January 4, 2017.

Integration Capacity Analysis

1. The ICA use cases for online maps and interconnection streamlining, as well as for distribution planning, are adopted.

2. The IOUs are ordered to use the iterative methodology for the online maps and interconnection streamlining use case, with the following additional methodological directives:

- The IOUs shall update ICA results for changed circuits (i.e., circuits that have been upgraded or have new DER interconnections) on a monthly basis.
- The IOUs shall employ 576 hourly profiles in the calculation and presentation of ICA results.
- The IOUs shall present six ICA results in online maps and downloadable datasets: three ICA values (uniform generation, uniform load, fixed solar photovoltaic [PV]) for two operational flexibility scenarios (reverse flow up to substation low-side busbar, operational flexibility limit [no reverse flow]). IOUs shall calculate ICA values with and without the No Reverse Flow at Supervisory Control and Data Acquisition Devices constraint for initial system-wide rollout in the same way they modeled these scenarios in Demo A.
- IOUs shall publish in their downloadable datasets the specific criteria violations (e.g., thermal, voltage, safety, protection) associated with the limiting ICA value.
- Each IOU shall model voltage regulating devices in initial system-wide rollout as it did for Demonstration Project A. Pacific Gas and Electric Company and Southern California Edison Company are directed to work with software vendors to enable voltage regulating devices to be "unlocked" (float) within iterative methodology, and shall report on progress on such work in Interim Reports. Long-term refinement discussions can also consider how to implement such methodology after initial system-wide rollout is complete.

- ICA shall be limited by pre-existing conditions (i.e., display an ICA value of zero) when adding DERs degrades pre-existing condition; and 2) ICA shall not be limited by pre-existing condition when adding DERs improves pre-existing condition. IOUs shall document their methods for handling pre-existing conditions in Interim Reports.
- The IOUs shall maintain technology-agnostic approach to calculating ICA values as employed in Demo A that does not make assumptions on technology-specific DER portfolios or response to California Independent System Operator dispatch.
- The IOUs shall continue to standardize a common mapping structure and mapping functionality while using what was developed for Demo A for an initial system-wide rollout.
- The IOUs shall display the following attributes in their online ICA maps: Circuit ID; Circuit Load Profile; Section ID; Voltage (kV); Substation ID; Substation Load Profile; System; Customer class proportions on circuit; Existing generation (MW); Queued generation (MW); Total generation (MW); Hosting capacity for uniform generation (MW); Hosting capacity for uniform load (MW); and Hosting capacity for generic PV system (MW).
- The IOUs shall employ the methods for node reduction and limitation category reduction in the initial system-wide rollout.
- Each IOU shall use the same method to develop localized load shapes using Advanced Metering Infrastructure (AMI) and other customer load data as it employed in Demo A for the initial system-wide rollout.

3. The IOUs shall implement the ICA to achieve the online map plus interconnection use case within nine months of the issuance of this decision.

4. The IOUs shall file a Tier 1 Advice Letter within 30 days of the issuance of this decision detailing the ICA methodology for the online map and interconnection use case as prescribed by the May 2, 2016 and August 23, 2016 Rulings and modified by this Decision.

5. The IOUs shall file a work plan for the nine-month ICA rollout including high-level process descriptions and estimated (non-binding) interim milestones within 30 days of the issuance of this decision.

6. The IOUs shall serve and file an interim report at the midway point of the nine-month implementation period, and a final report at the completion of the implementation period. Reports shall describe, at a minimum:

- Progress towards nine-month deadline and interim milestones as laid out in work plan;
- IOU/vendor progress towards incorporating required changes to tools;
- Changes and updates to the models;
- Description of process to maintain network model accuracy during updates;
- Unforeseen issues or delays; tool or software inadequacies; and
- Actual costs of system-wide implementation and ongoing administration/monthly updates (to be filed in the second and final report).

7. The IOUs shall file a Tier 2 Advice Letter to request non-substantive modifications to methodology and timelines that arise during system-wide rollout.

Locational Net Benefit Analysis

8. The LNBA use cases for: 1) Public Tool and Heat Map; 2) prioritization of candidate distribution deferral opportunities as part of the Distribution Investment Deferral Framework; and 3) providing location-specific avoided transmission and distribution (T&D) inputs into the Integrated Distributed Energy Resources DER Avoided Cost Calculator (DERAC) for cost-effectiveness evaluation, informing DER incentive levels, and other applications, are adopted.

9. Within 60 days of the issuance of this decision, the IOUs are ordered to file and serve proposals for modeling and/or methodological approaches that enable LNBA to calculate Distribution Planning Area-level avoided T&D values for input into the DER Avoided Cost Calculator. These proposals should meet the requirements laid out in the below discussion section. The Commission will then solicit further input from stakeholders and related Commission proceedings regarding the cross-procedural needs for LNBA, and the Commission's Energy Division will convene joint workshops, as needed, to discuss parties' proposals, including technical feasibility issues, data sources, and assumptions. The Commission will adopt and/or modify the IOUs' proposals in the subsequent proposed decision ruling on ICA and LNBA long-term refinements.

10. This decision orders system-wide LNBA implementation for the Deferral Framework-related public tool and heat map use case by the same deadline, to be adopted in the Track 3 Proposed Decision, by which the IOUs will be ordered to present candidate distribution deferral projects, with the following guidelines:

a. The IOUs shall populate the LNBA with candidate deferral projects and DER attributes as determined through the planning process, based on guidance and deferral screens adopted in the forthcoming Track 3 decision in this proceeding;

b. The IOUs are directed to commence system wide implementation of the LNBA tool and heat map to the extent possible absent guidance on deferral screens and long term refinements.

11. The IOUs shall file and serve a work plan for LNBA implementation within 30 days from the issuance of this decision providing high-level process descriptions and estimated (non-binding) interim milestones.

12. The IOUs shall file and serve an interim report by January 31, 2018 documenting progress towards system-wide LNBA implementation that describes, at a minimum:

a. Progress towards implementation and interim milestones as set forth in the work plan.

b. IOU/E3 progress towards expanding the spreadsheet tool.

c. Status of 2017-2018 planning process with regards to identifying candidate deferral projects.

d. Unforeseen issues or delays.

13. The IOUs shall file a Tier 1 Advice Letter within 30 days of the issuance of this decision requesting establishment of a memorandum account to track the incremental costs of implementing the ICA and LNBA to the specifications ordered herein.

14. In Track 3, the Commission will address policy issues such as grid modernization and deferral framework. The Commission previously addressed Track 2 in Decision (D.) 17-02-007, revised by D.17-06-012.

This proceeding remains open.

1. Background

1.1. The Order Instituting Rulemaking

On August 14, 2014, the Commission opened Rulemaking (R.) 14-08-013 in order to establish policies, procedures, and rules to guide California Investor-owned Utilities (IOUs) in developing their Distribution Resource Plan (DRP) Proposals. We did so in accordance with the enactment of Assembly Bill (AB) 327,[2] an omnibus-style bill that impacted multiple aspects of the provision of regulated utility service and of the energy market, including Net Energy Metering (NEM), the Renewables Portfolio Standard, natural gas and electricity rates, and electricity resources. AB 327 added Pub. Util. Code § 769, which

[2] Stats. 2013, Ch. 611.

addressed both the IOUs' electric distribution planning protocols, as well as the Commission's obligation to review, modify, and approve the IOUs' DRP proposals:

> (a) For purposes of this section, distributed resources means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.
>
> (b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:
>
>> (1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation.
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>> (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.
>>
>> (4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.
>>
>> (5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

The IOUs met their July 1, 2015 filing deadline and their applications are identified as follows:

- Pacific Gas and Electric Company (PG&E): Application (A.) 15-07-006;
- Southern California Edison Company (SCE): A.15-07-002; and
- San Diego Gas & Electric Company (SDG&E): A.15-07-003.

1.2. The Scoping Memo and Ruling

On January 27, 2016, the assigned Commissioner and then-assigned Administrative Law Judge issued their *Scoping Memo and Ruling* that, *inter alia*, divided this proceeding into three separate yet concurrent Tracks, categorized as follows:

Track 1: Methodological Issues (quasi-legislative);

Track 2: Demonstration and Pilot Projects (ratesetting);[3] and

Track 3: Policy Issues (quasi-legislative).

The *Scoping Memo and Ruling* stated that Track 1 would handle issues related to the Integrated Capacity Analysis (ICA), Locational Net Benefit Analysis (LNBA), and the authorization for Demonstration Projects A and B associated with researching and improving the ICA and LNBA methodologies.

1.3. The Clarifying Rulings

On May 2, 2016, the assigned Commissioner issued his *Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B (May 2, 2016 Ruling)*. The methodological refinements were set forth in Attachment A to the *May 2, 2016 Ruling*. The *May 2, 2016 Ruling* also adopted LNBA methodology for use in DRP's Demonstration Project B, and authorized the IOUs to perform

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[3] The Commission addressed Track 2 in its two decisions, Decision (D.) 17-02-007 *(Decision on Track 2 Demonstration Projects),* and D.17-06-012 (*Decision on Revised Track 2 Demonstration Projects*).

LNBA methodology for one Distribution Planning Area in each Utility's service area.

In response to the IOUs' *Joint Motion to Modify Specific Potions of the May 2, 2016 Ruling*, the assigned Commissioner granted the IOUs' Joint Motion on August 23, 2016 *via* an Assigned Commissioner's Ruling (ACR) that made two edits to *May 2, 2016 Ruling*: First, page 6 of the Attachment to the *May 2, 2016 Ruling* was revised to insert the following direction: "The IOUs are also authorized to develop a power flow-based, or 'iterative,' methodology, as proposed in their respective Applications, for comparison purposes and may submit results based on both methodologies."[4] Second, page 33 of the Attachment was revised to state: "The IOUs shall execute and present their LNBA results under two DER growth scenarios: (a) as used in each IOU's distribution planning process; and (b) the very high DER growth scenario, as filed in their applications."

1.4. IOU Demonstration Project A Reports and the ICA Working Group Report

In December 2016, the IOUs submitted their final Demonstration Project A reports, which the ICA Working Group collectively discussed in the first quarter of 2017. These reports summarized the Demonstration Project A results, lessons learned, and the IOUs' recommendations on the methodology selection and feasibility of implementation of the ICA across the entire distribution system.

On March 15, 2017, the ICA Working Group filed their ICA Final Report that included recommendations in the following categories: (1) Uses of ICA; (2) Development of Common IOU methodology; (3) Refinements to ICA

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[4] *August 23, 2016 Ruling* at 2.

methodology; (4) Timeline; and (5) Modifications to ICA methodology and schedule. In Table 1, we summarize the ICA Working Group Report recommendations for Commission guidance:

Table 1. ICA Working Group Report Recommendations for Commission Policy Guidance

Item No.	Report Section	Recommendation (Summary)	Consensus/ non-consensus
1	4	**ICA Use Case: Inform and Improve the Rule 21 Interconnection Process** Commission should adopt an interconnection use case for ICA and should [adopt a number of guiding principles related to incorporating ICA values into Rule 21], for discussion in a forthcoming Rule 21 proceeding.	Consensus
2	4	**ICA Use Case: Informing the Distribution Planning Process and Decision Making** Commission should provide guidance on ICA uses within planning context, and the role the Working Group (WG) is expected to play in developing these uses. Coordination with Track 3 needed.	Consensus
3	5.4	**Development of Common IOU Methodology** All three IOUs should employ a consistent methodology for the interconnection use case.	Consensus

Item No.	Report Section	Recommendation (Summary)	Consensus/ non-consensus
4	5.4	**Development of Common IOU Methodology** Majority of WG recommends iterative methodology for interconnection use case, and for the value displayed in online maps to be value used in the interconnection study process. PG&E recommends a "blended" approach in which streamlined methodology is used for online maps, then iterative is used to analyze specific conditions within interconnection process.	Non-Consensus
5	6.1	**Timeline for Implementation** IOUs recommend implementing ICA within 12 months of CPUC decision on ICA methodology. California Solar Energy Industry Association (CalSEIA) recommends implementation within 12 months of ICA WG report filing. Many stakeholders have no opinion regarding the implementation timeline, only that short-term refinements are included when ICA is first rolled out system-wide.	Non-Consensus
6	6.2	**Recommended Regulatory Process** Commission should establish a Tier 1 Advice Letter process to incorporate two types of modifications to ICA during the initial rollout: 1) incorporation of long- term/ongoing methodological refinements; 2) scope/schedule modifications based on short-term refinements or unexpected roadblocks in the implementation process.	Consensus

Item No.	Report Section	Recommendation (Summary)	Consensus/ non-consensus
7	7	**Hourly Profiles, Frequency of Updates for Iterative Methodology** IOUs provide rough cost estimates for monthly v. annual updates, 96 v. 576 hourly profiles. IOUs make detailed recommendations on these questions in Demo A reports. Subset of non-IOU stakeholders recommend 576 hourly profiles and weekly updates to changed circuits, though would accept monthly updates at a minimum. Non-IOU subset also recommends IOUs track implementation process, update process, and actual costs associated with each for three years, such that methodology can be revisited based on experience.	Non-Consensus
8	8	**Frequency of Updates, Representativeness of ICA Value** ICA should be updated frequently enough to provide an adequately representative value to inform developer project design and siting and for use in the interconnection process.	Consensus
9	8	**Frequency of Updates to Reflect System Changes** IOUs support system-wide monthly updates for initial rollout with consideration of higher frequency updates on case-by-case, on demand, or weekly basis. Other WG stakeholders believe ICA should be updated annually system-wide, and that specific nodes/feeders be updated weekly to reflect queued projects, new interconnections, or other system changes above a defined threshold.	Non-Consensus

Item No.	Report Section	Recommendation (Summary)	Consensus/ non-consensus
10	9	**Presentation of ICA Results** Six ICA results should be presented in online maps and downloadable datasets: three ICA values (uniform generation; uniform load; fixed solar photovoltaic [PV]) for two operational flexibility scenarios (reverse flow up to substation low-side busbar; operational flexibility limit [i.e., no reverse flow])	Consensus
11	10.2.1	**Voltage Regulating Devices** Consensus that voltage regulating devices should be "unlocked" (float) within iterative methodology, but no consensus regarding process and timing of implementation. IOUs recommend each IOU models voltage regulating devices in initial system-wide rollout as it did for Demo A and work with software vendors (CYME) to include this functionality. Other WG members recommend IOUs work with software vendors to develop this functionality before initial system-wide rollout.	Non-Consensus
12	10.2.2	**Operational Flexibility** ICA values should be calculated with and without the No Reverse Flow at Supervisory Control and Data Acquisition (SCADA) Devices constraint for initial system-wide rollout (see section 9), which is how the IOUs modeled these scenarios in Demo A per ACR requirements.	Consensus

Item No.	Report Section	Recommendation (Summary)	Consensus/ non-consensus
13	10.4	**Treatment of Pre-Existing Conditions** ICA should be limited by pre-existing conditions (i.e., display an ICA value of zero) when adding Distributed Energy Resources (DER) degrades pre- existing condition; ICA should not be limited by pre-existing condition when adding DER improves pre-existing condition.	Consensus
14	10.4	**Pre-Existing Conditions in System-Wide Rollout** The treatment of Pre-Existing Conditions described in Recommendation 13 should be included in initial system-wide rollout, which would require the IOUs to create an automated process to efficiently evaluate feeders and substations for pre-existing conditions, if DERs make things better or worse, and whether to compute an ICA result based on if DERs improve or degrade the condition.	Consensus
15	11.1.1	**DER Portfolios/California Independent System Operator (CAISO) Dispatch** IOUs should continue to calculate ICA values as they did for Demo A, in which assumptions were not made regarding technology-specific DER portfolios or response to CAISO dispatch.	Consensus
16	11.2	**Common Mapping Structure** The IOUs should continue to standardize a consistent mapping structure and mapping functionality while using what was developed for Demo A for the first system-wide rollout.	Consensus

Item No.	Report Section	Recommendation (Summary)	Consensus/ non-consensus
17	11.2.1	**Map Attribute Display** The following attributes should be available across all three IOU maps: Circuit ID; Section ID; Voltage (kV); Substation; System; Customer class proportions on circuit; Existing generation (MW); Queued generation (MW); Total generation (MW); Hosting capacity for uniform generation (MW); Hosting capacity for uniform load (MW); and Hosting capacity for generic PV system (MW).	Consensus
18	11.3	**Computational Efficiency** Methods for node reduction and limitation category reduction are appropriate for use in the initial system-wide rollout, though will need to reevaluate these methods as computing power and other factors change over time.	Consensus
19	11.3	**Hourly Load Profile Reduction** Differing opinions as to whether hourly load profile reduction should be used. IOUs tested reduction of 576 hourly profiles in Demo A, and they documented their thoughts on this method in their Demo A reports, but non-IOU WG stakeholders recommend continued use of a 576 profile (see Section 7).	Non-Consensus

Item No.	Report Section	Recommendation (Summary)	Consensus/ non-consensus
20	11.4	**Office of Ratepayer Advocates (ORA) 12 Metrics of Success** "Red" metric indicates full-scale deployment of ICA should be delayed until such issues are addressed. The only "red" metric: tweaks to circuit models in CYME/Synergi required for convergence are currently lost when new data from geographic information systems (GIS) and other data sources is incorporated into power flow circuit model. SCE however responds that it will create the necessary steps to maintain accuracy of the network models as part of the deployment and should not delay system-wide implementation.	Non-Consensus
21	11.5	**Localized Load Shapes from Advanced Metering Infrastructure (AMI)/Other Source** Each IOU should use the same method it employed in Demo A for initial system- wide rollout.	Consensus
22	12	**Cost Recovery** Commission should adopt a process to facilitate IOU requests for funding to support ICA implementation. Additional cost recovery may be necessary depending on the implementation requirements adopted by the Commission.	Consensus

1.5. IOU Demonstration Project B Reports and the LNBA Working Group Report

In December 2016, the IOUs submitted their final Demonstration Project B reports. These reports summarized the Demonstration Project B results, lessons learned, and the IOUs' recommendations on the methodology calculation and next steps regarding implementation of LNBA.

On March 8, 2017, the LNBA Working Group filed their LNBA Final Report, which (1) summarized the Working Group's recommendations; (2) provided support for a Commission decision on Demonstration Project B; (3) provided input for the Commission to develop an implementation plan for further development of LNBA; and (4) outlined refinements for the Commission to address before the adoption and full system-wide rollout of a LNBA methodology and tool. In Table 2, we summarize the LNBA Working Group Report Recommendations for Commission Policy Guidance:

Table 2. LNBA Working Group Report Recommendations for Commission Policy Guidance

Item No.	Report Section	Recommendation (Summary)	Consensus/ non-consensus
1	3.1	**Demo B Compliance with ACR** Formally recognize that Demo B projects/reports are in compliance with ACR requirements.	Consensus
2	3.1	**LNBA Provisional Use** Demo B methodology is appropriate for provisional use in Integration of Distributed Energy Resources (IDER) pilot, DRP Demo C, and Deferral Framework (recommendation	Consensus
3	3.2	**LNBA Use Cases: Public Tool; Deferral Prioritization** Demo B methodology can be used for two use cases: 1) public tool/heat map; 2) prioritizing candidate deferral projects.	Consensus

Item No.	Report Section	Recommendation (Summary)	Consensus/ non-consensus
4	3.2	**Expanded LNBA Use Case: Commission Guidance Needed** Additional Commission guidance needed on expanded application of LNBA beyond the two Demo B use cases to meet LNBA use case of providing locational T&D inputs for cost-effectiveness and DER sourcing beyond deferral solicitations.	Non-Consensus
5	3.3	**System-Wide Implementation Timing** Deferral Framework should be adopted before implementing LNBA system-wide.	Consensus
6	5.2.2	**Continued Development of Transmission and Distribution (T&D) Values** T&D values to be included in future modifications of LNBA tool should only reflect grid services adopted by IDER Competitive Solicitation Framework (CSF).	Non-Consensus

1.6. The April 19, 2017 ACR

On April 19, 2017, the Assigned Commissioner issued his ruling entitled *Assigned Commissioner's Ruling Requesting Comments on the Integration Capacity Analysis and Locational Net Benefits Analysis Final Short-Term Working Group Reports (April 19 Ruling)*. Parties were invited to respond to a series of questions regarding the consensus and non-consensus recommendations contained in the ICA and LNBA Working Group Reports.

With respect to the ICA Working Group Report, the parties were asked to provide comments to the following questions:

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

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?

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.

   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);

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

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 WG members before submitting modification requests?

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?

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?

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?

With respect to the LNBA Working Group Report, the parties were asked to respond to the following questions:

1. Did the IOUs adequately execute Demonstration Project B according to the requirements of the May 2 and August 23 ACRs?
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?
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.
4. Implementation Questions (especially for IOUs):

   a. What are the steps for expanding the spreadsheet tool system-wide and how long will that take?

   b. What are the steps for expanding the heat map system-wide and how long will that take? To what degree will system-wide heat map expansion build off of circuit models being developed for ICA?

   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?

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?

2. Discussion

2.1. ICA

2.1.1. The IOUs' Demonstration Projects Comply with the May 2, 2016 Ruling and the August 23, 2016 Ruling Requirements

In reaching this conclusion, the Commission has reviewed the IOUs' Demonstration Project A Reports and compared them to the May 2, 2016 and August 23, 2016 Ruling requirements. Attached to this decision as Appendix A is the result of that comparative analysis in the form of a detailed matrix, which we incorporate herein by this reference. As both the following high-level summary and the attached matrix demonstrate, there is sufficient factual information to conclude that the IOUs' Demonstration A Projects satisfy the *May 2, 2016* and *August 23, 2016 Ruling* requirements[5] in the following respects:

(Ruling Section) 1.1. – Load forecasting and DER growth scenarios: Each IOU used a transparent method for both load forecasting and DER growth in their ICA calculation methodology. The Demonstration Project A growth scenarios were conducted using both a two-year growth scenario and additional growth scenarios as proposed in their respective IOU DRP applications.

1.3 – Baseline Method Steps: The IOUs' Demonstration Project A Reports contained the required analysis that was performed down to the specific nodes within each line section. A Load Forecasting

[5] The IOUs' compliance matrices that are set forth in their December 2016 Demonstration Project A reports also demonstrate compliance with the May 2, 2016 and August 23, 2016 Ruling requirements. (See PG&E Report at 161-166; SCE Report at 90-97; and SDG&E Report at 81-87.)

Analysis Tool was used to develop load profiles at feeder, substation, and system levels through aggregating representative hourly customer load and generation profiles. Load profiles were created for each Distribution Planning Area (DPA), comprised of 576 data points. A Power Flow Analysis Tool was also used to model conductors, line devices, loads, and generation components, which the IOUs updated with the latest circuit configurations based on changes to the GIS asset map. Both the Load Forecast Tool and the Power Flow Analysis Tool were used to evaluate power system criteria (i.e. Thermal Criteria, Power Quality/Voltage Criteria, Protection Criteria, and Safety/Reliability Criteria. Finally, the ICA calculations were performed using a layered abstraction approach and the resulting data was made publicly available using the Renewable Auction Mechanism (RAM) Program Map.

1.4 – Specific Modifications to Include in Baseline Method: The IOUs in Demonstration Project A adequately quantified the capability of the distribution system to host the DER. Devices that contribute to reactive power on the circuit (e.g. capacitors), and their effects on the power flow analysis were included in the power flow model. The power flow analysis was calculated across multiple feeders, and all feeders that are electrically connected with a substation were included in the analysis. The ICA was modified, as needed, to reflect DERs that reduce or modify the forecast loads, and the IOUs disclosed their assumptions that were utilized to customize the power flow model and all other calculations that could impact the ICA values.

1.4.3. – Different Types of DERs: The baseline methodology, with modifications described in the May 2, 2016 Ruling, was used as a provisional common ICA methodology in the Demonstration A Projects. The methodology evaluated the capacity of the system to host DERs by using a set of typical DER operational profiles: Uniform General; PV; PV with Tracker; electric vehicle (EV)—Residential (EV Rate); EV—Workplace; Uniform Load; PV with Storage; Storage—Peak Shaving; and EV—Residential (Time of Use rate). The IOUs then quantified the hosting capacity for the portfolios of resource types using PG&E's approach with representative portfolios of solar; solar and stationary storage; solar, stationary storage, and load control; and solar, stationary storage, load control, and EVs. The IOUs proposed a method for evaluating DER portfolio operational profiles that minimized computation time which accomplishing the goal of evaluating the hosting capacity for various DER portfolios system-wide.

1.4.5 – Thermal Ratings, Protection Limits, Power Quality (including voltage), and Safety Standards: The Demonstration Project A Reports included all the different types of defined power-system criteria and sub-criteria in the analysis. The IOUs agreed upon on a common approach to representing protection limits in the ICA, limited the criteria and threshold values and, in an intermediate status report, explained how they were applied in the Demonstration A Projects. The IOUs provided documentation to identify and explain the industry, state, and federal standards embedded within the ICA limitation criteria and threshold values. The ICA results included, with each feeder, the feeder-level loading and voltage data, customer-type breakdown, and existing DER capacity. The ICA results also included information on the type, frequency, timing (diurnal and seasonal) and duration of the thermal, voltage, or system protection constraints that limit hosting capacity on each feeder segment. The information was provided in a downloadable format and with sufficient detail to allow customers and DER providers to design portfolios of DER to overcome the constraints.

1.4.6 – Publish the Results via Online Maps: The IOUs met the requirement that all information made available in this phase of ICA development shall be made available via the existing ICA maps in a downloadable format. The feeder map data was also made available in a standard shapefile format, such as ESRI ArcMap GIS data files. The maps and associated materials and download formats were consistent across all IOUs, and were clearly explained through the inclusion of keys to the maps and associated materials. Explanations and the meanings of the information displayed were also provided. Finally, existing RAM map information and ICA results were displayed on the same map.

1.4.7 – Time Series of Dynamic Models: The IOUs utilized a consistent dynamic or time-series analysis method in their Demonstration A Projects.

2 – General Requirements:

Power Flow Scenarios: IOUs modeled two scenarios in their Demonstration A Projects: (a) DER capacity does not cause power to flow beyond the substation busbar; and (b) DERs' technical maximum capacity is considered irrespective of power flow toward the transmission system.

Project Locations: The IOUs modified the Demonstration A Project locations proposed in the Applications to include two DPAs that cover as broad a range as possible of electrical characteristics encountered in the respective IOU systems (e.g., one rural DPA and one urban DPA). The IOUs clarified if their originally proposed Demonstration A Project locations satisfies one of the two required DPAs and what their other proposed DPA(s) are. The IOUs justified in their detailed plans the basis for choosing each DPA for the Demonstration Projects.

Project Detailed Implementation Plan: Per the *May 2, 2016 Ruling*, the IOUs submitted detailed implementation plans for Demonstration Project A execution on June 16, 2016, including metrics, schedule, and reporting intervals. The Demonstration Project A Plans included:

(a) Documentation of specific and unique project learning objectives for the Demonstration A Projects, including how the results of the projects are used to inform ICA development and improvement;

(b) A detailed description of the revised ICA methodology that conforms to the guidance in Section 1.3 and Section 1.4 above, including a process flow chart;

(c) A description of the load forecasting or load characterization methodology or tool used to prepare the ICA;

(d) Schedule/Gantt chart of the ICA development process for each utility, showing: i. Any external (vendor or contract) work required to support it; and ii. Additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested;

(e) Any additional resources required to implement Demonstration Project A not described in the Applications;

(f) A plan for monitoring and reporting intermediate results and a schedule for reporting out. At a minimum, the Working Group shall report out at least two times over the course of Demonstration Project A: 1) an intermediate report; and 2) the final report;

(g) Electronic files shall be made available to the CPUC Energy Division and ORA to view and validate inputs, models, limit criteria, and results. Subject to appropriate confidentiality rules, other parties may also request copies of these files;

(h) Any additional information necessary to determine the probability of accurate results and the need for further qualification testing for the wider use of the ICA methodology and to provide the ultimate evaluation of ex-post accuracy; and

(i) ORA's proposed twelve (12) criteria or metrics of success to evaluate IOU ICA tools, methodologies and results are adopted and should be used as guiding principles for evaluating ICA.

2.1.2. The Demonstration Project A Methodology is Able to Achieve the Two ICA Use Cases Defined in the ICA Working Group Final Report: Interconnection Streamlining and Distribution Planning

In its Final Report, the Working Group identified two uses of ICA that it describes in a high-level format as follows: (1) inform and improve Rule 21 interconnection procedures (Table 1, Item 1); and (2) inform and identify DER growth constraints in the planning process (Table 1, Item 2).[6] The Working Group asserts that ICA results can help customers and third parties design DER systems that do not exceed hosting capacity by providing accurate information about the amount of DER capacity that can be interconnected at a specific location without significant distribution system upgrades.[7]

[6] ICA Working Group Final Report at 7-8.

[7] *Id.* at 8.

We agree with the Working Group that ICA results can be used to inform interconnection siting decisions and to facilitate a streamlined and transparent interconnection process, and adopt the ICA interconnection streamlining and online map use case. As the assigned Commissioner noted in his Ruling on Guidance for Public Utilities Code Section 769—Distribution Resource Planning (Guidance Ruling), one of the key purposes of the DRP is to dramatically streamline the interconnection process. ICA results can assist customers and third parties design DER systems by providing accurate information about the amount of DER capacity that can be interconnected at specific locations without significant distribution system upgrades. The Commission expects that the recently-opened Rule 21 proceeding[8] will coordinate with the development of ICA to implement the Working Group's recommendations.

The second use for ICA would be to inform and identify DER growth constraints in the IOUs' distribution planning process. The Working Group asserts that the ICA information may be used as an input into system planning processes to identify when and where capacity upgrades are needed on the distribution system as a result of DER growth scenarios.[9] However, the Working Group states it was not able to make specific recommendations regarding appropriate methodology (or the details of that methodology) that would ultimately serve this use case the best.[10] As such, the Working Group in its Final Report proposes to define the planning use case further as a high-priority

[8] R.17-07-007, issued July 21, 2017.

[9] ICA Working Group Final Report at 8.

[10] *Id.* at 10.

long-term refinement issue, and requests additional guidance from the Commission on uses of ICA within the planning context.[11]

We agree that ICA results should play a role in the distribution planning process, and adopt the ICA distribution planning use case. In the near-term, ICA results may be used to identify grid locations facing hosting capacity constraints in light of DER growth scenarios that would be candidates for grid upgrades to accommodate projected DER growth. In the future, ICA results may guide sourcing and procurement of DER solutions in specific locations with available hosting capacity and locational value. Per the *June 7, 2017 Assigned Commissioner's Ruling Setting Scope and Schedule for Continued Long Term Refinement Discussions Pertaining to the Integration Capacity Analysis and Locational Net Benefits Analysis in Track One of the Distribution Resources Plan Proceeding (June 7, 2017 Ruling)*, developing methodological details to achieve the planning use case for ICA is among the high-priority items for consideration in the ICA Working Group long-term refinement discussions. Methodological recommendations to achieve the ICA planning use case will be addressed in a Proposed Decision disposing of long-term refinement issues, anticipated in the first quarter of 2018. Furthermore, guidance regarding the use of ICA in the annual distribution planning process and new DRP process will be provided in a forthcoming Proposed Decision on Track 3 issues.

[11] *Id.*

2.1.3. Approval of the Iterative Methodology for Online Maps and Interconnection Streamlining

The IOUs tested the ICA under two separate methodologies: the "iterative method," which is based on iterations of successive power flow simulations at each node on the distribution system; and the "streamlined method," which uses a set of equations and algorithms to evaluate power system criteria at each node on the distribution system.[12] The Working Group found that the use of an iterative simulation parallels what IOUs would perform as part of a detailed interconnection study and, as such, would produce more accurate results.[13] As a result, a majority of the Working Group (SCE, SDG&E, and all non-IOU Working Group stakeholders) recommend that the iterative methodology be used for the interconnection use case to update the interconnection maps, improve the interconnection process, and be deployed in the first system-wide deployment of ICA. In contrast, PG&E recommends the use of a "blended" approach where both the iterative and streamlined methods would be used within the interconnection use case. PG&E asserts this approach could result in a more cost-effective implementation given that the iterative method requires additional IT and engineering resources to complete.[14] But in examining PG&E's proposal, the other Working Group members concluded that the approach was unsatisfactory in meeting the goal of the interconnection use case, which seeks to move towards an automated process that requires less manual review by

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[12] *Id.* at 11.

[13] *Id.*

[14] *Id.* at 12. *See also* PG&E Demonstration A Final Report.

engineers and would enable the ICA information displayed on the map to be the same as what is applied in the interconnection process (Table 1, Item 4).[15]

The Commission agrees with the majority of the Working Group and approves the iterative methodology and rejects PG&E's blended approach. We echo the Working Group's consensus (Table 1, Item 8) that ICA values should be adequately representative to inform a DER developer's project design and siting for use in the interconnection process, and are thus concerned that interconnection applicants would not be able to rely on hosting capacity data derived from the streamlined method due to its relatively higher levels of inaccuracy.[16] We reiterate that adopting a consistent ICA methodology across the three IOUs is an important principle, one that the Commission stressed in its Guidance Ruling and about which the Working Group was in agreement in its Final Report (Table 1, Item 3), and will help to avoid developer confusion once rolled into the Rule 21 process.

With respect to the update frequency and hourly profile options, the Commission again agrees with the Working Group's recommendation that the ICA data displayed in the maps should be updated frequently enough and with sufficient hourly profiles as to accurately predict a developer's ability to achieve a streamlined interconnection decision. For the initial implementation of ICA for interconnection purposes, we order the IOUs to update ICA results for changed circuits (i.e. circuits that have been upgraded or have new DER interconnections)

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[15] *Id.* at 13.

[16] E.g., SDG&E Demo A Report at 45: "While the streamlined method typically provided results faster than the iterative method, users need to consider the streamlined results as being less accurate than results from the iterative method, and . . . possibly not valid for certain types of applications."

on a monthly basis (Table 1, Item 9). The Commission can revisit this update frequency determination once the IOUs and developers have gained sufficient experience utilizing monthly-updated ICA results as part of the Rule 21 interconnection process.

With respect to 576 versus 96 hourly profiles, the number of hours evaluated in the load profiles should be set at 576 hours since the alternative option of 96 hours would not be a strong enough step toward improved seasonal granularity (Table 1, Items 7 and 19). We also agree with Clean Coalition[17] that evaluating 576 hourly profiles would have a negligible impact on the cost of implementing ICA as compared to evaluating 96 hourly profiles during the monthly update process.

Finally, based on the consensus recommendations from the Working Group, we add the following additional methodological directives:

- IOUs shall present six ICA results in online maps and downloadable datasets: three ICA values (uniform generation, uniform load, fixed PV[18]) for two operational flexibility scenarios (reverse flow up to substation low-side busbar, operational flexibility limit [no reverse flow]). IOUs shall calculate ICA values with and without the No Reverse Flow at SCADA Devices constraint for initial system-wide rollout in the same way they modeled these scenarios in Demo A (Table 1, Items 10 and 12).[19]

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17 *Clean Coalition Comments on the Integration Capacity Analysis and Locational Net Benefits Analysis Final Short-Term Working Group Reports*, May 10, 2017, at 6.

18 Development of a standard PV generation profile is in scope for ICA long-term refinement discussions, per the *June 7, 2017 Ruling*. The PV profiles resulting from those efforts should be reflected in ICA results following a Proposed Decision on long-term refinement issues, anticipated in the first quarter of 2018.

19 ICA Working Group Final Report at 22 and 26.

- IOUs shall publish in their downloadable datasets the specific criteria violations (e.g., thermal, voltage, safety, protection) associated with the limiting ICA value.
- Each IOU shall model voltage regulating devices in initial system-wide rollout as it did for Demo A. PG&E and SCE are directed to work with software vendors (CYME) to enable voltage regulating devices to be "unlocked" (float) within iterative methodology, and shall report on progress on such work in Interim Reports (Table 1, Item 11).[20]
- 1) ICA shall be limited by pre-existing conditions (i.e., display an ICA value of zero) when adding DER degrades pre-existing condition; and 2) ICA shall not be limited by pre-existing condition when adding DER improves pre-existing condition. IOUs shall document their methods for handling pre-existing conditions in Interim Reports (Table 1, Items 13 and 14).[21]
- The IOUs shall maintain technology-agnostic approach to calculating ICA values as employed in Demonstration Project A that does not make assumptions on technology-specific DER portfolios or response to CAISO dispatch (Table 1, Item 15).[22]
- The IOUs shall continue to standardize a common mapping structure and mapping functionality while using what was developed for Demo A for an initial system-wide rollout (Table 1, Item 16).[23]
- The IOUs shall display the following attributes in their online ICA maps: Circuit ID; Circuit Load Profile; Section ID; Voltage (kV); Substation ID; Substation Load Profile; System; Customer class proportions on circuit; Existing generation (MW); Queued generation (MW); Total generation (MW); Hosting capacity for

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[20] *Id*. at 24.

[21] *Id*. at 28.

[22] *Id*. at 29.

[23] *Id*. at 31.

uniform generation (MW); Hosting capacity for uniform load (MW); and Hosting capacity for generic PV system (MW) (Table 1, Item 17).[24]

- o Each IOU shall use the same methods for node reduction and limitation category reduction as it employed in its Demonstrations Project A for the initial system-wide rollout (Table 1, Item 18).[25]
- o Each IOU shall use the same method to develop localized load shapes using AMI and other customer load data as it employed in its Demonstration Project A for the initial system-wide rollout (Table 1, Item 21).[26]

Aside from these methodological directives, we encourage the IOUs to continually standardize the modeling assumptions by which they develop and input system component data for use in ICA calculations. The lack of standardization between the IOUs' modeling assumptions was reported[27] to be a larger driver of divergence in ICA results than was attributed to different methodologies (e.g., iterative versus streamlined) or power flow analysis software (e.g., CYME versus Synergi). Continued standardization between the IOUs' modeling assumptions will thus drive consistency amongst the three IOUs' ICA results as they work to implement and maintain the models on an ongoing basis.

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[24] *Id*.

[25] *Id*. at 33.

[26] *Id*. at 37.

[27] PG&E Demonstration Project A Report at 108-109; SCE Demonstration Project A Report at 49-50; SDG&E Demonstration Project A Report at 48-49.

2.1.4. Deadline for Filing ICA Operational for Online Map and Interconnection use Case and Interim Progress Reports

As stated above, we asked the parties if was reasonable to impose a 12-month implementation schedule. In response, the Working Group points out that multiple stakeholders involved in the drafting of the ICA Working Group Report expressed no preference in recommendations regarding an implementation timeline. The IOUs anticipate that 12 months will be necessary for ICA implementation following Commission adoption of a Final Decision, but note that they will continue to work on preparation activities, including preparation of network models, data sources, work force plans, and implementation procedures while a Final Decision is pending (Table 1, Item 5).[28]

Although no parties were opposed to a 12-month implementation schedule, the Commission orders that the ICA be operational for the online map and interconnection use case within nine months of the issuance of this decision. Our adoption of a shorter implementation schedule is motivated by the recently-opened Rule 21 Interconnection proceeding, which includes a primary goal of "[considering] whether to revise Rule 21 to streamline interconnection of distributed energy resources by incorporating the results of the Integration Capacity Analysis under development in Rulemaking 14-08-013."[29] Furthermore, the lag between the issuance of the Working Group's Final Report and this Decision has provided the IOUs additional time to make progress on the preparation activities listed above.

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[28] ICA Working Group Final Report at 14.

[29] R.17-07-007, issued July 21, 2017 at 1.

To ensure that the IOUs are moving efficiently and in a timely manner towards this goal, we order the following. First, the IOUs shall file a Tier 1 Advice Letter within 30 days of the issuance of this decision detailing the ICA methodology for the interconnection use case as prescribed by the *May 2, 2016* and *August 23, 2016 Rulings* and modified by this Decision. Second, the IOUs shall file a work plan within 30 days from the issuance of this decision providing a high-level process description and estimated (non-binding) interim milestones by which they will implement the ICA per the guidance in this decision. Finally, the IOUs must file an interim report at the midway point of the nine-month implementation period and one final report at the completion of the implementation period that describe, at a minimum:

- Progress towards the nine-month deadline and interim milestones as set forth in the work plan;
- IOU/vendor progress towards incorporating required changes to tools;
- Changes and updates to the models;
- Description of process to maintain network model accuracy during updates (Table 1, Item 20);
- Description of methods to handle pre-existing conditions (Table 1, Item 14);
- Unforeseen issues or delays, such as tool or software inadequacies; and
- In the final report, the IOUs will provide actual costs of system-side implementation and ongoing administration.

2.1.5. Adoption of Tier 2 Advice Letter Modification Process

The Working Group recommends that the Commission establish a process to incorporate modifications to the ICA, both as part of the implementation of ICA on its first system-wide rollout, and as future enhancements are added to the methodology. Specifically, the Working Group recommends that the Commission should permit the filing of a Tier 1 Advice Letter to approve ICA methodology refinements, as well as requests for modification of the scope and schedule due to unforeseen circumstances during the full-system rollout (Table 1, Item 6).[30]

We find this request to be reasonable. As the scope and complexities of the system-wide implementation of ICA cannot be predicted with certainty at this time, an Advice Letter modification process would create the flexibility for the IOUs to identify and phase in refinements as more information becomes known. However, we adopt the Working Group's request with the following modifications. First, we adopt a Tier 2 Advice Letter for the IOUs to request non-substantive modifications to the scope and schedule of system-wide ICA implementation. We agree with ORA's reasoning as expressed in comments[31] that a Tier 2 Advice Letter would be more appropriate for this purpose, given that a Tier 1 Advice Letter would be effective immediately on the date of filing, and that the Working Group Final Report did not include a discussion on which modifications would be considered "non-substantive." As such, a Tier 2 designation would properly allow the opportunity for stakeholders to review the advice letter and provide input prior to its disposition and effectiveness. Second, we recognize that the Working Group continues to refine and enhance the ICA methodology through long-term refinement discussions. Per the *June 7, 2017*

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30 ICA Working Group final Report at 15-16.

31 *Comments of the Office of Ratepayer Advocates on Assigned Commissioner's Ruling Requesting Comments on the Integration Capacity Analysis and Locational Net Benefits Analysis Final Short-Term Working Groups (ORA Comments)*, May 10, 2017, at 6-7.

Ruling, the Working Group is due to file its Final Report on long-term refinements on January 7, 2018, which will be disposed of *via* a subsequent Decision. We defer to that Decision to determine how long-term refinements to the ICA methodology will be deployed on a system-wide basis, as well as to adopt a process for considering ongoing methodological modifications beyond the completion of long-term refinement discussions.

2.1.6. Tracking Additional ICA Costs

The Working Group requests that the Commission adopt a process to facilitate IOU requests for additional funding to support the ICA implementation as additional costs become known (Table 1, Item 22).[32] We find this request to be reasonable as there may be additional and or unanticipated costs associated with the full system rollout. As such, we authorize the IOUs to establish a memorandum account to track the incremental costs of ICA implementation. The IOUs can seek to recover these costs in their next General Rate Case (GRC), in which costs booked to the memorandum account will be subject to a reasonableness review and confirmation that such costs are incremental to previously-approved GRC budgets.

2.2. LNBA

2.2.1. The IOUs' Demonstration B Projects Comply with the May 2, 2016 Ruling and the August 23, 2016 Ruling Requirements

The Working Group in its Final Report[33] requests that the Commission formally recognize that the IOU Demonstration B Projects are in compliance with

[32] ICA Working Group Final Report at 38.

[33] LNBA Working Group Final Report at 11.

the requirements laid out in the *May 2, 2016* and *August 23, 2016 Rulings* (Table 2, Item 1). The Commission has reviewed the IOUs' Demonstration Project B Reports and compared them to the *May 2, 2016* and *August 23, 2016 Ruling* requirements. Attached to this decision as Appendix C is the result of that comparative analysis in the form of a detailed matrix, which we incorporate herein by this reference. As both the following high-level summary and the attached matrix demonstrate, there is sufficient factual information to conclude that the IOUs' Demonstration B Projects on balance satisfy the *May 2, 2016* and *August 23, 2016 Ruling* requirements[34] in the following respects, with one significant deficiency discussed in greater detail in the below section on LNBA use cases.

> **(Ruling Section) 4.1 – Distribution Planning Area (DPA) Selection/Projects for Deferral**: The IOUs complied with the directive that they evaluate one near-term (0-3 year project lead time) and one longer-term (3 or more year lead time) distribution infrastructure project for possible deferral. The IOUs also demonstrated at least one voltage support/power quality-or-reliability/resiliency-related deferral opportunity in addition to one or more capacity-related opportunities.
>
> **4.3 – LNBA Methodology Requirements**: The IOUs utilized a primary analysis that utilizes the Distributed Energy Resources Avoided Cost Calculator (DERAC) for system-level values. The IOUs also developed certain system-level values that are not yet included in the DERAC (e.g. Flexible RA, renewables, integration costs, etc.) to the extent feasible.

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[34] The IOUs' compliance matrices that are set forth in their December 2016 Demonstration Project B reports also demonstrate compliance with the May 2, 2016 and August 23, 2016 Ruling requirements. (See PG&E Report at 57-61; SCE Report at 96-101; and SDG&E Report at A3-1-A3-3.)

4.4.1 – LNBA Specific Requirements

(1)(A) - Project Identification: The IOUs identified the full range of electric services that result in avoided costs for all locations within the DPAs selected for analysis. The values include electrical services associated with distribution grid upgrades identified in (i) the utility distribution planning process; (ii) the circuit reliability improvement process; and (iii) the maintenance process that the IOUs consider deferrable by DERs.

(1)(B)(i) – List of Locations for Projects: The IOUs developed a list of locations where upgrade projects, circuit reliability, or maintenance projects may occur over each of the planning horizons.

(1)(B)(ii) – Project Costs: The IOUs used existing approaches for estimating costs of required projects identified.

(1)(B)(iii) – Time Horizon of System Upgrade Needs: The IOUs defined the time horizon for system upgrade needs in three categories that correspond to the near term forecast (1.5—3 year), intermediate term (3-5 year), and long term (5-10 year).

(1)(B)(iv) – List of Electric Services from Projects: The IOUs prepared location-specific lists of electric services associated with the planned distribution upgrades and presented the electric service needs in machine readable and map-based formats.

(1)(B)(v) – DER Capabilities to Provide Electric Services: For the electrical services identified, the IOUs identified the DER capabilities that would provide the electrical service.

(1)(B)(vi) – Specifications of System Upgrade Needs: The IOUs described the various needs underlying the distribution grid upgrades in terms of total capacity increase. The IOUs also provided an equipment list of components required to accomplish the capacity increase, maintenance action, or reliability improvement.

(1)(B)(vii) – Compute Avoided Cost: The IOUs computed a total avoided cost for each upgrade project within the DPA selected for analysis using the Real Economic Carrying Charge (RECC) method to calculate the deferral value of these projects. Avoided costs were then assigned to the four avoided cost categories in the DERAC calculator for this location.

<u>(1)(C) – Distribution System Services</u>: The IOUs provided the location of distribution system services and the specifications for providing them on the LNBA maps. The IOUs, however, did not quantify opportunities for conservation voltage reduction (CVR) and volt/VAR (Voltage Ampere Reactive) optimization as part of the Demo B analysis, though they did outline formulas and/or processes by which CVR benefits could be calculated.[35]

<u>(2) – Transmission Capital and Operating Expenditures</u>: With respect to avoided costs related to transmission capital and operating expenditures, the IOUs were not able to quantify the co-benefit value of ensuring that preferred resources relied upon to meet planning requirements in the CAISO's 2015-2016 transmission plan, Section 7.3, materialize as assumed in those locations. Instead, the IOUs set the default avoided transmission value in the LNBA tool at zero, which is the value found in the NEM Public Tool that the Commission developed in R.14-07-002.[36]

<u>(4) – Flexible Generation</u>: For the avoided cost of generation capacity for any DERs that provide flexible generation, the IOUs assumed a 2016 value of $20/kW-year with a 5% escalation for subsequent years.[37] The IOUs, however, did not provide work papers that contained descriptions of the methods or data used to arrive at this value.

<u>(6) – Avoided Costs—Renewable Integration, Societal, and Public Safety</u>: The IOUs used technology-specific renewable integration costs adopted in D.14-11-042. However, the IOUs did not quantify societal or public safety benefits for Demo B, and instead cited

[35] PG&E Demonstration Project B Report at 15; SCE Demonstration Project B Report at 15-16; SDG&E Demonstration Project B Report at 12-13.

[36] Per the *June 7, 2017 Ruling*, the LNBA Working Group is developing a non-zero, location-specific avoided transmission value as a high-priority long-term refinement item.

[37] PG&E Demonstration Project B Report at 47-48; SCE Demonstration Project B Report at 62-63; SDG&E Demonstration Project B Report at 54.

regulatory activities in IDER and Integrated Resource Planning (IRP) that are working towards such outcomes.

(7) – Methodology Description: The IOUs provided detailed descriptions of the method used for Demonstration Project B, with a description of the modeling techniques or software used, as well as the sources and characteristics of the data used as inputs.

4.4.2 – Other Related LNBA Requirements:

(1) Heat Map: The IOUs made their LNBA results available via heat map, as a layer in the online ICA map. The electric services at the project locations were displayed in the same map format as the ICA.

(2) – DER Growth Scenarios: The IOUs executed and presented their LNBA results under two DER growth scenarios: (a) as used in each IOU's distribution planning process; and (b) the very high DER growth scenario, as filed in their applications.

5.1 – General Requirements

(c) – Equipment Investment Deferral: The IOUs identified whether the following equipment investments could be deferred or avoided by DER in the projects included for LNBA assessment: (a) voltage regulators; (b) load tap changers; (c) capacitors; (d) VAR compensators; (e) synchronous condensers; (f) automation of voltage regulation equipment; and (g) voltage instrumentation.

(d) – Implementation Plan: The IOUs submitted detailed implementation plans for Demonstration Project B execution on June 16, 2016. The plans included a description of the revised LNBA methodology; a description of the load forecasting or load characterization methodology or tool used to prepare the LNBA; a schedule/Gantt chart of the LNBA development process for each utility showing any external work required to support it; additional project details and milestones including deliverables, issues to be tested, and tool configurations for testing; additional resources required to implement Demonstration Project B not described in the Applications; a plan for monitoring and reporting intermediate results; and a schedule for reporting out at least two times over the course of the Demonstration Project B.

2.2.2. Affirm LNBA Use Cases

The LNBA Working Group reached consensus on two use cases for the LNBA developed according to the Demonstration Project B methodology (Table 2, Item 3). The first is an LNBA Public Tool and Heat Map (and associated data) that customers and DER providers can use to identify potential optimal locations for deploying DER based on candidate deferral opportunities identified in the distribution planning process, along with detailed information about the required DER attributes necessary to achieve such deferrals. The second is using LNBA to help prioritize candidate distribution deferral opportunities as part of the Distribution Investment Deferral Framework, under consideration in Track 3 of this proceeding. We agree that the LNBA should be used for these purposes, and direct the IOUs to implement the Demonstration Project B methodology for ongoing application towards these ends, according to the guidance provided below.

However, the Working Group did not reach consensus on application of the LNBA methodology beyond these two use cases, most notably to develop locational avoided cost values for use in IDER cost-effectiveness evaluation (Table 2, Item 4). Until now, cost-effectiveness analysis of programs and tariffs for demand- and supply-side DERs has lacked a locational dimension. Cost-effectiveness evaluations have been informed through the Commission-approved DERAC, which estimates the fixed and variable costs that IOUs avoid as a result of DER capacity. The DERAC however uses the generic marginal T&D costs in each IOU's respective GRC Phase II.[38] Marginal

[38] SCE and SDG&E use a single territory-wide value for marginal T&D costs, while PG&E develops marginal T&D costs for each operating division in its service territory.

distribution costs are calculated primarily for ratemaking purposes, for use in revenue allocation and rate design and reflect little to none of the spatial variability in the cost of operating and maintaining the distribution grid. Similarly, marginal transmission costs, which the IOUs use to determine a floor price for discounted rates, also do not reflect geographic variations in cost. AB 327 looked to address this deficiency by requiring the IOUs to "Evaluate locational benefits and costs of distributed resources located on the distribution system," which can be used to "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."

Based on these requirements, early DRP guidance[39] instructed the IOUs to develop a unified locational net benefits methodology consistent across all three IOUs based on the DERAC, enhanced to explicitly include location-specific values in order to specify the net benefit that DERs can provide in a given location. Further guidance proposed[40] consideration of a process whereby location-specific, distribution-level avoided costs developed in the DRP would be paired with non-location-specific or system-level values in the IDER cost-effectiveness framework. Such guidance was reinforced by a staff proposal in the IDER proceeding that, as a part of a four-part process to improve the cost-effectiveness framework, recommended "Phase 2: in coordination with the Distribution Resources Planning (DRP) proceeding (R.14-08-013), improve the

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39 *Guidance Ruling*, Attachment 4.

40 DRP Roadmap Staff Proposal, November 16, 2015, at 18-20.

relationship between cost-effectiveness and actual system conditions."[41] In sum, the Commission has intended the LNBA to link existing programs and cost-effective tariffs to actual conditions across different locations on the distribution system.

Following these initial directives, the Commission has gone on to define broader uses for the LNBA in related proceedings. First, D.16-01-044, deferred substantial changes to NEM incentive levels until 2019, when the LNBA would be sufficiently developed to estimate the locational value of DERs.[42] The presumption is that the next regime of NEM incentives would be tailored to the relative costs and benefits of DER deployment at given locations on the grid. Furthermore, the Integrated Resource Planning (R.16-02-007) effort initiated by Senate Bill 350 seeks to develop supply curves for DERs based on distribution system costs and benefits in order to determine optimal resource portfolios to meet state greenhouse gas and resource procurement mandates.[43]

Given the Commission's statements on these matters, we affirm that a third use case for LNBA is to develop a comprehensive quantification of DER value at any location on the distribution grid for IDER sourcing and

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[41] *IDSM Cost-Effectiveness Mapping Project Report and Staff Proposal* at 8, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10742.

[42] D.16-01-044 at 20-22, 60-61.

[43] *Administrative Law Judge's Ruling Seeking Comment on Staff Proposal on Process for Integrated Resource Planning*, May 16, 2017, at 46-47: "The ability of a capacity expansion model to represent the location of demand-side resources depends on the availability of location-specific information about the costs and benefits of those resources. It is anticipated that ongoing work in other proceedings, including DRP, IDER, and [Energy Efficiency], will eventually inform the development of a supply curve of location-specific DERs in IRP, and the cost of each DER would reflect its net location-specific costs and benefits. Key challenges for the development of such a supply curve will be determining the appropriate level of geographic granularity for use in capacity expansion modeling and the appropriate way to bundle different DER types."

cost-effectiveness evaluations, informing DER incentive levels, providing distribution-level costs and benefits information to IRP, and other potential related applications. The LNBA tool developed for Demonstration Project B is not able to achieve this use case, which is essential for meeting the requirements of Pub. Util. Code § 769(b)(2) and (b)(3), reproduced here:

> **(b)(2)** - Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives; and
>
> **(b)(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.

In affirming this LNBA use case, we also address the issue of defining the breadth of potential location-specific DER benefits. The IOUs in their DRP applications[44] proposed to define the avoided T&D costs associated with DERs as the costs of specific, identified, planned T&D system upgrades. As the Demo B guidance noted,[45] while this is a necessary way to value avoided T&D costs, it may not be sufficient to capture the value of the full range of potential benefits that DERs can provide at any location. To correct this deficiency, Demonstration

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[44] A.15-07-002 at 60-62; A.15-07-003 at 38-44; A.15-07-006 at 66-73.

[45] *May 2, 2016 Ruling* at 26: "For T&D-related avoided costs, rather than using the avoided T&D cost in the E3 avoided cost calculator, the IOUs were directed to develop new models or methods of estimation. The IOU's applications propose to replace the avoided T&D cost parameters in the DERAC with four categories of T&D avoided costs to separately reflect the various costs associated with (1) transmission systems, (2) sub-transmission and substations, (3) distribution system reliability, and (4) distribution system power quality. The IOUs proposed to define the avoided T&D costs of DERs as the costs of specific, identified, planned T&D system upgrades. While this is a necessary way to value avoided T&D costs, it may not be sufficient to capture the value of the full range of potential benefits of DERs. **Therefore, this guidance ruling provides direction to address this deficiency." [Emphasis added.]**

Project B guidance directed the IOUs to develop a comprehensive quantification of DER value at any location on the distribution grid for IDER sourcing and cost effectiveness evaluations. Despite this explicit direction from the Commission, the IOUs developed the LNBA to calculate the estimated avoided costs of candidate distribution deferral projects, and reiterated in their Demonstration Project B reports[46] their position that DERs only provide locational value to ratepayers and the grid when they defer or avoid traditional capital investments, such as those that stem from discrete system deficiencies identified in the course of distribution (or transmission) planning.

We disagree. First, many DERs have expected asset lives beyond the 10-year planning horizon over which the IOUs plan their distribution and transmission system, and thus can provide long-term benefits that cannot be captured by deferrals identified in the IOUs' T&D planning windows. Methods to reflect long-term DER value in the LNBA are currently in scope for LNBA Working Group long-term refinement discussions.[47] Second, a number of value components under consideration in long-term refinement discussions, such as smart inverter services and asset life extensions, can provide granular grid and ratepayers benefits independent of investment deferrals.

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[46] E.g., PG&E Demo B Report, at 12: "In order for the DER to have real value to customers, it must defer a future capital investment . . . If the DER capacity enhancement fails to defer a future investment(s) there is simply no added value for utility customers;" SCE Demo B Report, at 13: "[T]he value of the voltage support service is directly determined by the deferral value of a planned voltage support project;" SDG&E Demo B Report at 10: "DERs can provide ratepayer benefit if they are able to defer or eliminate a future capital infrastructure investment required to increase back-tie capacity."

[47] *June 7, 2017 Ruling* at 12-13.

Having established that location-specific DER value is not limited to the spatial or temporal granularity associated with deferring planned capital projects, we return to the third LNBA use case of specifying the net benefit that DERs can provide at any given location. The LNBA tool developed for Demonstration Project B allows a user to calculate the estimated avoided costs that DER non-wires alternatives can capture as part of targeted distribution deferrals, the attributes of which must be input manually for each specific deferral project. The LNBA heat map then displays the indicative avoided costs for the electrical area over which DER deployment could achieve those deferrals. Deferral opportunities (and other location-specific value components) occur at different distribution system granularities, and as such are inherently unable to provide a consistent locational signal on which to inform IDER cost-effectiveness studies and non-RFO DER sourcing mechanisms. Instead, the LNBA must be able to flexibly calculate net benefits at the distribution system granularity and value aggregation method required by the particular application (e.g., portfolio, program, tariff, or contract) being evaluated.

Additionally, the LNBA must move beyond solely calculating avoided costs of DER deployment if it is to adequately develop locational signals for use in other policy arenas. Indeed, we agree with PG&E[48] that methods to evaluate costs related to increased investment in distribution or transmission infrastructure should be developed for inclusion in LNBA in order to meet the

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[48] *Comments of Pacific Gas and Electric Company (U 39 E) on Assigned Commissioner's Ruling Requesting Comments on the Integration Capacity Analysis and Locational Net Benefits Analysis Final Short-Term Working Group Report*, May 10, 2017, at 6-7.

requirements of AB 327, especially Pub. Util. Code § 769(b)(1).[49] Types of increased investments could entail grid modernization investments aimed at reliably accommodating high penetrations of DERs, or otherwise proactive investments aimed at increasing hosting capacity in light of forecasted DER growth in a given electrical area. In this way, LNBA can adequately calculate location-specific T&D costs and benefits.

2.2.3. Proposals to Achieve Third LNBA Use Case, Calculate DER Integration Costs, and Create a Central Distribution System Model and Data Access Platform

In order for LNBA to efficiently incorporate DER integration costs and develop location-specific T&D avoided cost values for input into DERAC, we envision further iterations of the LNBA tool and heat map beyond the versions built for Demonstration Project B.

As discussed above, the current version of DERAC uses generic marginal T&D costs calculated in the IOUs' GRC Phase II, which reflect the present value of estimated future spending proposed in the GRC Phase I to meet forecasted incremental distribution capacity needs.[50] Thus, in order for LNBA to replace the

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[49] Pub. Util. Code § 769(b)(1): "Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distribute resources provide to the electrical grid or costs to ratepayers of the electrical corporation."

[50] E.g., A.16-06-013, *Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation and Rate Design*, Exhibit (PG&E-9), Volume 1, at 6-2 – 6-3: "[Marginal Distribution Capacity Costs] are calculated . . . in two steps. First, the present values of capacity-related incremental investments are divided by the present values of incremental capacity additions yielding values for incremental investment costs per unit of capacity. Then, second, the incremental investment costs per unit of capacity are converted to an annualized marginal cost per unit of capacity by applying a RECC factor and appropriate loadings.

generic T&D values in DERAC with more location-specific ones, LNBA must reflect an estimated cost of future spending to meet the forecasted needs at a given system granularity.

The Commission for Demonstration Project B required the IOUs to implement LNBA for one DPA. DPAs are divisions of the IOUs' service territories that aggregate substations and circuits over a cohesive geographic area for purposes of distribution planning. We find this, at a minimum, to be an appropriate system resolution at which to initially define location-specific avoidable T&D costs over the 10-year planning horizon. DPA-level avoided costs calculated for LNBA should only reflect the planned investments that can be deferred or avoided by DER, plus any non-deferral-related value DERs can provide. Planned T&D spending that is considered non-avoidable, including asset repair and replacement, non-capacity-related reliability projects, Operations and Maintenance, emergency response, and new service connections,[51] should not be included. In theory, these values should add up to the amounts the IOUs have requested in the GRC for the same spending categories, plus any contingency budgets that can be estimated through the process described below.

It is unlikely that the IOUs will identify deferrable projects that can result in avoidable T&D costs for each and every DPA in a given 10-year planning window. However, that does not mean that such DPAs will be completely devoid of grid needs that require mitigation through capital projects. The inherent uncertainty of forecasting and the dynamic nature of distribution system needs require the IOUs to routinely repurpose approved GRC budgets to

[51] PG&E Demonstration Project B Report at 20; SCE Demonstration Project B Report at 18-19; SDG&E Demonstration Project B Report at 19-20.

meet emerging, unanticipated needs of maintaining and operating the distribution system. As such, avoided T&D costs calculated for each DPA should include a probability of unanticipated T&D spending that is avoidable by DERs, up to a 30-year window consistent with the maximum useful life of certain types of DERs.[52] This topic is in scope for LNBA Working Group long-term refinement discussions,[53] but is not specifically scoped to develop values for each DPA. Such probabilities could reflect sensitivities for high-trajectory load and DER growth forecasts that result from fuel switching-related electrification or rapid DER adoption, and could be tied back to historical system conditions and investments in a given area. For instance, a DPA in which a substation capacity upgrade was recently completed would carry a low probability for unanticipated T&D spending, relative to a DPA in which major capacity upgrades have not been completed for some time.

One necessary modification to the Demonstration Project B methodology to achieve the LNBA cost-effectiveness use case involves the exclusion of DER growth forecasts. The LNBA tool developed to the Demonstration Project B methodology calculates an estimated value for deferrable distribution projects that have been planned to meet incremental grid needs beyond the anticipated "autonomous growth" of DERs. Such autonomous DER growth occurs as a result of existing DER tariffs and programs. It thus follows that the DPA-level avoided T&D values developed for input into DERAC should not reflect the

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[52] E.g., *Comments of the Solar Energy Industries Association and Vote Solar on the Assigned Commissioner's Ruling Requesting Comments on the Integration Capacity Analysis and Locational Net Benefit Analysis Short-Term Working Group Reports*, May 10, 2017, at 9.

[53] *June 7, 2017 Ruling*, at 13, Table 6, Group III, Item 8: "Develop a methodology to quantify the likelihood of an unplanned grid need (deferrable project) emerging in a given location."

forecast of autonomous DER growth anticipated to occur *because of* existing tariffs and programs. Determining grid needs and planned projects absent DER forecasts would properly reflect the value of autonomous DER growth, and would enable DERAC to accurately inform DER tariffs and programs.[54] It is essential that the IOUs analyze the future needs of each DPA based on a demand forecast absent DERs, to properly estimate the avoided T&D values to be used in DERAC.

However, we recognize the need for the IOUs to apply a trajectory DER growth forecast in the planning process to determine DER integration costs stemming from proposed Grid Modernization or hosting capacity-related investments. Such integration costs should be calculated for each DER technology at the DPA level and reported separately from the avoided T&D costs calculated for each DPA (i.e., LNBA should report gross DPA-level costs and benefits and not net them). This would allow for DPA-level avoided T&D costs to be included in the DER Avoided Cost Calculator, while associated DER integration costs would be included alongside DER program and administrative costs in IDER cost-effectiveness calculations.[55] Similarly, DPA-level cost and benefit values would be aggregated into system-level values in order to develop DER supply curves in the IRP.

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[54] To clarify, "DER growth forecasts" refers to forecasts of future anticipated DER adoption and not to existing DERs. Existing DERs should remain in the baseline forecast in the "no DER growth" planning forecast to develop DPA-level avoided T&D values.

[55] It is ultimately a question for the IDER proceeding to determine how to apply LNBA cost and benefit information in examining new DER rates, tariffs, and programs. This includes the need to balance any transition from existing to new DER rates, tariffs, and programs and ensure DERs are not receiving double payments.

Last, we anticipate developments to the LNBA tool and heat map to realize broad efficiencies in data collection, visualization, and access. As noted in the IOUs' Demonstration Project B Reports, the LNBA heat map is being developed on the same platform as the ICA map, enabling users to access data through the same interface.[56] We expand on this single interface by envisioning a central distribution system circuit model and data access platform developed for use across ICA and LNBA, as well as the Grid Modernization and Distribution Investment Deferral Frameworks under development in Track 3 of this proceeding.

Pursuant to this order, the IOUs will create and publish network models of their entire primary distribution systems for ICA calculations, which are based on attribute data of relevant distribution system infrastructure and device ratings and settings. This will provide the IOUs with a pre-populated database of distribution infrastructure to which cost and benefit information can be flexibly assigned and aggregated across different system granularities. This is particularly important for capturing value components such as asset life extension and smart inverter services, which in some instances occur at the line section or nodal level and would require readily-available distribution system component and attribute data in order to properly compute. Additionally, this would allow the IOUs to seamlessly integrate the LNBA into proposed ongoing Distribution Resource Planning activities under consideration in Track 3 of this proceeding. Staff have proposed a new IOU deliverable referred to as the Grid

[56] PG&E Demonstration Project B Report at 11; SCE Demonstration Project B Report at 9; SDG&E Demonstration Project B Report at 6.

Needs Assessment[57] that would publish in online maps and downloadable datasets the grid deficiencies, planned investments, and candidate deferral projects that result from the annual distribution planning process. Utilizing a central distribution system model would allow candidate deferral projects displayed in the Grid Needs Assessment to be seamlessly input into LNBA.

Following ORA's proposal in comments,[58] we hereby order the IOUs, within 60 days of the issuance of this decision, to file and serve proposals for modeling and/or methodological approaches that enable LNBA to calculate DPA-level avoided T&D values for input into DERAC. These proposals should meet the requirements laid out in this discussion section, recognizing that quantifying the likelihood of unplanned deferrable projects and developing a central modeling and data access platform, as proposed, necessarily depend on developments in the LNBA long-term refinement discussions and in Track 3 of this proceeding, respectively. The Commission will then solicit further proposals and input from stakeholders and related Commission proceedings regarding the cross-procedural needs for LNBA, and the Commission's Energy Division will convene joint workshops, as needed, to discuss parties' proposals, including technical feasibility issues, data sources, and assumptions. The Commission will then adopt and/or modify the IOUs' proposals in the proposed decision ruling on ICA and LNBA long-term refinements.

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[57] *Assigned Commissioner's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff White Paper on Grid Modernization (Grid Modernization Ruling), May 16, 2017, Attachment A, at 20-23; Administrative Law Judge's Ruling Requesting Answers to Stakeholder Questions Set Forth in the Energy Division Staff Proposal on a Distribution Investment Deferral Framework (Deferral Framework Ruling),* June 30, 2017, Attachment A at 13-15.

[58] *ORA Comments* at 11-12.

2.2.4. Order System-Wide LNBA Implementation

The Working Group is in consensus that the Distribution Infrastructure Deferral Framework (Deferral Framework) envisioned in Track 3 should be adopted before the LNBA tool and heat maps are deployed system-wide (Table 2, Item 5). They assert that the Deferral Framework is a key input into the LNBA and has yet to be finalized as part of Track 3 in this proceeding. This is because the deferral screening criteria established as part of the Deferral Framework will drive the IOUs' determination of candidate deferral projects and required DER attributes that serve as a key input into LNBA.

As of the drafting of this Proposed Decision, the Commission issued a Deferral Framework Staff Proposal on June 30, 2017,[59] which proposes, amongst other things, initial deferral screening criteria that the IOUs would use in the annual distribution planning process to identify candidate deferral projects, and an annual deliverable by which the IOUs would present those candidate deferral projects. These and other Track 3 issues are anticipated to be disposed of via Proposed Decision in the third quarter of 2017.

We order the IOUs to publish the first system-wide LNBA for the Deferral Framework-related public tool and heat map use case by the same deadline, to be adopted in the Track 3 Proposed Decision, by which IOUs will be ordered to present candidate distribution deferral projects. This deadline will coincide roughly with the completion of the 2017-2018 distribution planning process, and will allow candidate deferral projects to be displayed in LNBA in advance of anticipated Distribution Planning Advisory Group activities under consideration

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[59] Contained in the *Deferral Framework Ruling* (*see* Footnote 45).

in Track 3. We direct the IOUs to begin system-wide expansion of the LNBA public tool and heat map to the extent possible pending deferral screening guidance from the Track 3 decision anticipated later this year.

Similar to ICA, we order the IOUs to file a work plan within 30 days from the issuance of this decision providing a high-level process description and estimated (non-binding) interim milestones by which they will implement the LNBA per the guidance in this decision. The IOUs are required to file an interim status report by January 31, 2018 documenting progress towards system-wide LNBA implementation, that describes, at a minimum:

- Progress towards implementation and interim milestones as set forth in the work plan;
- IOU/E3 progress towards expanding the spreadsheet tool;
- Status of 2017-2018 planning process with regards to identifying candidate deferral projects; and
- Unforeseen issues or delays.

2.2.5. Continued Development of T&D Values

The LNBA Working Group included in its Final Report a non-consensus recommendation that T&D values to be included in future modifications of the LNBA tool should only reflect grid services adopted by the IDER CSF Working Group (Table 2, Item 6). We decline to adopt this as a principle for the ongoing development of the LNBA, and instead affirm that T&D values should be developed for inclusion in future versions of the LNBA tool pursuant to a Commission order.

2.2.6. Tracking Additional LNBA Costs

We authorize the IOUs to track the incremental costs of LNBA implementation in the same memorandum account established to track ICA implementation costs. We find this to be reasonable as there may be additional and or unanticipated costs associated with the full system rollout of LNBA. The IOUs can seek to recover to recover these costs in their next GRC, in which costs booked to the memorandum account will be subject to a reasonableness review and confirmation that such costs are incremental to previously-approved GRC budgets.

3. Categorization and Need for Hearing

This decision confirms that Track 1 of these consolidated proceedings is categorized as quasi-legislative. While the *Scoping Memo and Ruling* anticipated that there may be hearings, none were requested.

4. Comments on Proposed Decision

The proposed decision of the assigned Commissioner in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed and served on September 14, 2017 by Community Environmental Council, Green Power Institute (GPI), Clean Coalition, TURN, ORA, California Energy Storage Alliance, Interstate Renewable Energy Council (IREC), Solar Energy Industries Association, Solar, Vote Solar, Stem, and the IOUs (SDG&E, SCE, and PG&E jointly). Reply comments were filed and served on September 19, 2017 by the IOUs jointly, IREC, ORA, Solar, and Vote Solar.

The comments have not caused the Commission to make substantive changes to this decision. We have, however, made edits and clarifications in Sections 2.1.2., 2.1.3., 2.1.4., 2.2.3., 2.2.4., Conclusion of Law # 6, and Ordering Paragraphs 5, 9, 16, and 18,

The claims of legal and or factual error have been considered and rejected as unpersuasive.

5. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Peter V. Allen and Robert M. Mason III are the co-assigned Administrative Law Judges in this proceeding.

Findings of Fact

1. Each IOU's Demonstration Project A has complied with the requirements set forth in the May 2, 2016 and August 23, 2016 ACRs. As support for this finding, the Commission incorporates by reference the analysis and conclusions from the Compliance Matrix, attached to this decision as Appendix B.

2. Each IOU's Demonstration Project B has complied with the requirements set forth in the May 2, 2016 and August 23, 2016 ACRs. As support for this finding, the Commission incorporates by reference the analysis and conclusions from the Compliance Matrix, attached to this decision as Appendix C.

Conclusions of Law

1. Each IOU's Demonstration Project A should be approved.

2. Each IOU's Demonstration Project B should be approved.

3. The Integration Capacity Analysis use cases for online maps and interconnection streamlining, as well as for distribution planning, should be adopted.

4. The iterative methodology for online maps and interconnection streamlining, modified by the directives laid out in this decision, should be adopted.

5. The LNBA use cases (Public Tool and Heat Map; prioritization of candidate distribution deferral opportunities as part of the Distribution Investment Deferral Framework; and quantification of DER value at any location on the grid) should be adopted.

6. A system-wide LNBA implementation for the Deferral Framework-related public tool and heat map use case, corresponding with the completion of the 2017-2018 distribution planning process and further guidance from the Track 3 Proposed Decision, should be ordered.

7. The establishment of a memorandum account to track incremental costs of ICA should be affirmed.

8. The establishment of a memorandum account to track incremental costs of LNBA should be affirmed.

9. It is reasonable for the IOUs to file a Tier 1 Advice Letter requesting the establishment of a memorandum account to track the incremental costs of implementing the ICA and LNBA to the specifications ordered by this decision.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company's Demonstration Project A is approved.

2. Southern California Edison Company's Demonstration Project A is approved.

3. San Diego Gas and Electric Company's Demonstration Project A is approved.

4. The Integration Capacity Analysis (ICA) use cases for online maps and interconnection streamlining, as well as for distribution planning, are adopted.

5. The Investor-owned Utilities (IOUs) are ordered to use the iterative methodology for the online maps and interconnection streamlining use case, with the following additional methodological directives:

- The IOUs shall update Integration Capacity Analysis (ICA) results for changed circuits (i.e., circuits that have been upgraded or have new DER interconnections) on a monthly basis.
- The IOUs shall employ 576 hourly profiles in the calculation and presentation of ICA results.
- The IOUs shall present six ICA results in online maps and downloadable datasets: three ICA values (uniform generation, uniform load, fixed solar photovoltaic [PV]) for two operational flexibility scenarios (reverse flow up to substation low-side busbar, operational flexibility limit [no reverse flow]). IOUs shall calculate ICA values with and without the No Reverse Flow at Supervisory Control and Data Acquisition Devices constraint for initial system-wide rollout in the same way they modeled these scenarios in Demo A.
- IOUs shall publish in their downloadable datasets the specific criteria violations (e.g., thermal, voltage, safety, protection) associated with the limiting ICA value.
- Each IOU shall model voltage regulating devices in initial system-wide rollout as it did for Demonstration Project A. Pacific Gas and Electric Company and Southern California Edison Company are directed to work with software vendors to enable voltage regulating devices to be "unlocked" (float) within iterative methodology, and shall report on progress on such work in Interim Reports. Long-term refinement discussions can also consider how to implement such methodology after initial system-wide rollout is complete.
- ICA shall be limited by pre-existing conditions (i.e., display an ICA value of zero) when adding Distributed Energy Resources (DERs) degrades pre-existing condition; and 2) ICA shall not be limited by pre-existing condition when adding DERs improves pre-existing condition. Investor-owned Utilities shall document

their methods for handling pre-existing conditions in Interim Reports.

- The IOUs shall maintain technology-agnostic approach to calculating ICA values as employed in Demo A that does not make assumptions on technology-specific DER portfolios or response to California Independent System Operator dispatch.
- The IOUs shall continue to standardize a common mapping structure and mapping functionality while using what was developed for Demo A for an initial system-wide rollout.
- The IOUs shall display the following attributes in their online ICA maps: Circuit ID; Circuit Load Profile; Section ID; Voltage (kV); Substation ID; Substation Load Profile; System; Customer class proportions on circuit; Existing generation (MW); Queued generation (MW); Total generation (MW); Hosting capacity for uniform generation (MW); Hosting capacity for uniform load (MW); and Hosting capacity for generic PV system (MW).
- The IOUs shall employ the methods for node reduction and limitation category reduction in the initial system-wide rollout.
- Each IOU shall use the same method to develop localized load shapes using Advanced Metering Infrastructure and other customer load data as it employed in Demo A for the initial system-wide rollout.

6. Within nine months of the issuance of this decision, the Investor-owned Utilities shall implement the Integration Capacity Analysis to achieve the online map plus interconnection use case.

7. Within 30 days of the issuance of this decision, the Investor-owned Utilities shall file a Tier 1 Advice Letter detailing the Integration Capacity Analysis methodology for the online map and interconnection use case as prescribed by the May 2, 2016 and August 23, 2016 Rulings and modified by this Decision.

8. Within 30 days of the issuance of this decision, the Investor-owned Utilities shall file a work plan for the nine-month Integration Capacity Analysis rollout including high-level process descriptions and estimated (non-binding) interim milestones.

9. The Investor-owned Utilities (IOUs) shall serve and file an interim report at the midway point of the nine-month implementation period and a final report at the completion of the implementation period. Reports shall describe, at a minimum:

- Progress towards nine-month deadline and interim milestones as laid out in work plan;
- IOU/vendor progress towards incorporating required changes to tools;
- Changes and updates to the models;
- Description of process to maintain network model accuracy during updates;
- Unforeseen issues or delays; tool or software inadequacies; and
- Actual costs of system-wide implementation and ongoing administration/monthly updates (to be filed in the second and final report).

10. The Investor-owned Utilities shall file a Tier 2 Advice Letter to request non-substantive modifications to methodology and timelines that arise during system-wide rollout.

11. Pacific Gas and Electric Company's Demonstration Project B is approved.

12. Southern California Edison Company's Demonstration Project B is approved.

13. San Diego Gas and Electric Company's Demonstration Project B is approved.

14. The Locational Net Benefit Analysis use cases for: 1) Public Tool and Heat Map; 2) prioritization of candidate distribution deferral opportunities as part of the Distribution Investment Deferral Framework; and 3) providing location-specific avoided transmission and distribution inputs into the Integrated Distributed Energy Resources Distributed Energy Resources Avoided Cost Calculator for cost-effectiveness evaluation, informing Distributed Energy Resources incentive levels, and other applications, are adopted.

15. Within 60 days of the issuance of this decision, the Investor-owned Utilities (IOUs) are ordered to file and serve proposals for modeling and/or methodological approaches that enable Locational Net Benefit Analysis to calculate Distribution Planning Area-level avoided Transmission & Distribution values for input into the Distributed Energy Resources Avoided Cost Calculator. These proposals should meet the requirements laid out in the above discussion section, recognizing that quantifying the likelihood of unplanned deferrable projects and developing a central modeling and data access platform, as proposed, necessarily depend on developments in the Locational Net Benefit Analysis (LNBA) Working Group long-term refinement discussions and in Track 3 of this proceeding, respectively. The Commission will then solicit further input from stakeholders and related Commission proceedings regarding the cross-procedural needs for LNBA, and the Commission's Energy Division will convene joint workshops, as needed, to discuss parties' proposals, including technical feasibility issues, data sources, and assumptions. The Commission will then adopt and/or modify the IOUs' proposals in the proposed decision ruling on Integration Capacity Analysis and LNBA long-term refinements.

16. This decision orders system-wide Locational Net Benefit Analysis (LNBA) implementation for the Deferral Framework-related public tool and heat map use case by the same deadline, to be adopted in the Track 3 Proposed Decision, by which Investor-owned Utilities (IOUs) will be ordered to present candidate distribution deferral projects, with the following guidelines:

- The IOUs shall populate the LNBA with candidate deferral projects and Distributed Energy Resources attributes as determined through the planning process, based on guidance and deferral screens adopted in the forthcoming Track 3 decision in this proceeding;
- The IOUs are directed to commence system wide implementation of the LNBA tool and heat map to the extent possible absent guidance on deferral screens and long term refinements.

17. Within 30 days from the issuance of this decision, the Investor-owned Utilities shall file and serve a work plan for Locational Net Benefit Analysis implementation providing high-level process descriptions and estimated (non-binding) interim milestones.

18. By January 31, 2018, the Investor-owned Utilities (IOUs) shall file and serve an interim report documenting progress towards system-wide Locational Net Benefit Analysis implementation that describes, at a minimum:

a. Progress towards implementation and interim milestones as set forth in the work plan.

b. IOU/E3 progress towards expanding the spreadsheet tool.

c. Status of 2017-2018 planning process with regards to identifying candidate deferral projects.

d. Unforeseen issues or delays.

19. Within 30 days of the issuance of this decision, the Investor-owned Utilities shall file a Tier 1 Advice Letter requesting establishment of a memorandum account to track the incremental costs of implementing the Integration Capacity Analysis and Locational Net Benefit Analysis to the specifications ordered herein.

This order is effective today.

Dated September 28, 2017, at Chula Vista, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners