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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006

(NOT CONSOLIDATED)

In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005 (Filed July 1, 2015)
And Related Matters.	Application 15-07-007 Application 15-07-008

ASSIGNED COMMISSIONER'S RULING (1) REFINING INTEGRATION CAPACITY AND LOCATIONAL NET BENEFIT ANALYSIS METHODOLOGIES AND REQUIREMENTS; AND (2) AUTHORIZING DEMONSTRATION PROJECTS A AND B

Summary

As set forth in Attachment A, this ruling 1) refines the integration capacity and locational net benefit analysis methodologies and requirements, and 2) authorizes Demonstration Projects A and B. The methodologies, requirements, and demonstration projects that are the subject of this ruling were

discussed at their respective workshops and, in the case of integration capacity analysis, later memorialized in the workshop report.

1. Background

This rulemaking was opened to establish policies, procedures, and rules to guide California investor-owned utilities (IOUs) in developing their Distribution Resource Plan (DRP) Proposals, which they were required to file by July 1, 2015 in compliance with Pub. Util. Code § 769. This rulemaking will also provide direction regarding the IOUs' future procedures with respect to incorporating Distributed Energy Resources (DER) into the planning and operation of their electric distribution systems.

2. Discussion

On November 10, 2015, Commission staff convened a workshop on integration capacity analysis (ICA) methodologies and associated Demonstration Project A proposals. Following the ICA workshop, the IOUs produced an ICA workshop report.

On January 8, 2016, the then assigned Administrative Law Judge (ALJ)[1] issued a ruling inviting pre-workshop comments and alternatives to locational net benefits analysis (LNBA) methodologies. Pre-LNBA workshop comments were filed and served on January 26, 2016. Commission staff convened a workshop on the LNBA methodology and associated Demonstration Project B proposals on February 1, 2016.

On February 18, 2016, the then assigned ALJ issued a ruling inviting parties to offer comments on ICA methodologies, the ICA workshop report produced by the utilities, LNBA methodologies, the LNBA workshop, and

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[1] Gerald F. Kelly, who was reassigned and replaced by ALJ Robert M. Mason III on February 19, 2016.

Demonstration Projects A and B. The parties were instructed to address specific questions relative to the ICA components and LNBA methodologies.

IOUs and other interested parties filed and served their responses on March 3, 2016.

The assigned Commissioner, based on a review of the relevant filings, refines the ICA and LNBA methodologies and requirements on an interim basis for use in the demonstration projects. This ruling also authorizes Demonstration Projects A and B. The methodological refinements and terms of the authorization are set forth in Attachment A to this Ruling. For reference, the IOUs' Demonstration Project A and B proposals have been excerpted from their DRP applications and included as Attachment B.

IT IS RULED that:

1. The integration capacity and locational net benefit analysis methodologies and requirements are refined in accordance with Attachment A.
2. Demonstration Projects A and B are authorized in accordance with Attachment A.
3. The IOUs shall cooperate with the Energy Division's Executive Director (or those Energy Division staff designated by the Energy Division's Executive Director) to the extent clarifications or minor modifications are necessary to the pilot project requirements and/or working group guidance.

Dated May 2, 2016, at San Francisco, California.

/s/ MICHAEL PICKER
Michael Picker
Assigned Commissioner

ATTACHMENT A

ICA and LNBA Methodology, Demonstration Projects A and B

This Guidance attachment describes the modified Integration Capacity Analysis (ICA) and Locational Net Benefit Analysis (LNBA) methodologies that are approved for use in the Demonstration A and B projects and other specifications related to the Demonstration A and B projects.

1. ICA Methodology

1.1 Guidance Requirement Summary

This Guidance identifies nine functional requirements that the ICA must fulfill for use in Demonstration Project A. These nine functional requirements are derived directly from the original DRP Guidance Ruling[2] and presented in Table 1 showing how they map to the original Guidance Ruling. Based on a review of IOU DRP Applications, party comments, and information from the Energy Division this Guidance directs the IOUs to modify their ICA methodologies in these nine technical areas. The methodology described in this ruling corresponds to the nine technical criteria listed in the table.

For sections of the Guidance that are not are not directly related to the technical methodology of the ICA itself, the status of IOU compliance with each of these areas is discussed in the table below.

Table 1

ICA Guidance Section 1.a Subparagraph	Corresponding ICA Technical Methodology Requirement Number or Status of IOU Compliance
i. Perform a distribution system	1. Quantify the Capability of the

[2] Full citation needed ACR Attachment Section 1.a Integration Capacity Analysis at 3

Integration Capacity Analysis down to the line section or node level, utilizing a common methodology across all Utilities. This analysis quantifies the capability of the system to integrate DER within thermal ratings, protection system limits and power quality and safety standards of existing equipment. Results of the analysis are to be published via online maps maintained by each Utility and available to the public. Initial Integration Capacity Analysis is to be completed by each Utility by July 1, 2015.[3]	Distribution System to Host DER 2. Common Methodology Across All IOUs 3. Analyze Different Types of DERs 4. Line Section or Nodal Level on the Primary Distribution System 5. Thermal Ratings, Protection Limits, Power Quality (including Voltage), and Safety Standards 6. Publish the Results via Online Maps
ii. Perform an analysis that assesses current system capability together with any planned investments within a 2 year period. Clearly articulate the assumptions and methodology used for load and DER forecasts over the 2 year period.	The IOUs have complied with this requirement as discussed below.
iii. Perform an analysis using dynamic modeling methods, which are uniform across all Utilities, and circuit performance data. The analysis shall avoid the use of heuristic approaches where possible.	7. Use Time Series Models 8. Avoid Heuristic approaches, where possible
iv. Assess the state of DER deployment and DER deployment projections. For each of the identified DERs, the Utilities should provide current levels of deployment territory wide, plus an assessment of geographic dispersion with circuits that exhibit high levels of penetration identified.	In their DRP filings, the IOUs have provided this assessment. The current DER deployment levels affect the ICA calculation in the load forecast as described in ii. above.

[3] ACR Attachment, Section 1, subsection a, p 3.

v. If a Utility is unable to conduct dynamic analyses for all feeders down to the line section or node, as an initial phase the Utility shall conduct an integration capacity analysis on a select set of representative circuits, including all related line sections. Utilities shall agree, as necessary, on the methodology used to select the representative circuits. The Utilities must include their methodology for selecting representative circuits as part of this analysis. The analysis of representative circuits described in this section should not be construed as a substitute for the ultimate goal of fully analyzing all distribution circuits in the Utility service territory, but should be considered as an initial phase for the July 1 filing.	Per criterion 4 above, the IOUs are required to perform the analysis to the line section or node. For purposes of Demonstration Project A, the IOUs are required by this Ruling to perform the complete ICA analysis for all feeders down to the line section or node on two Distribution Planning Areas (DPA). The schedule for completing ICA analysis of all circuits as required by the original DRP Guidance item v is described in each IOU's DRP filed July 1, 2015. The IOUs have complied with Section v of the Guidance as of the date of their Application.
vi. Specify a **process for regularly updating the Integration Capacity Analysis to reflect current conditions**. The process in place for updating the Renewable Auction Mechanism monthly is a good starting point. Where current Utility capabilities are inadequate **to conduct a dynamic, line section -level integration capacity analysis, specify a plan for developing these capabilities, including a schedule.**	The schedule for achieving full dynamic ICA is specified in each IOU DRP application as follows: • PG&E: complete • SDG&E: 2016-2017 • SCE: July 1, 2017 The process and frequency of updating the ICA analysis is a topic referred to the ICA Working Group for resolution in the Working Group Final Report.
vii. Specify recommendations for utilizing the Integration Capacity Analysis to support planning and streamlining of Rule 21 for distributed generation and Rule 15 and Rule 16	Policy on uses of ICA analysis is discussed in the body of the ruling. These scope items are the subject of workshops proposed for Q3 2016 by the Scoping Memo

assessments of EV load grid impacts, with a particular focus on developing new or improved 'Fast Track' standards.	
Demonstrate Dynamic Integrated Capacity Analysis ("Demo A") [4] Develop a specification for a demonstration project where the Utilities' Commission-approved Integration Capacity Analysis methodology is applied to all line sections or nodes within a Distribution Planning Area (DPA). The specification should include a detailed implementation schedule. This demonstration shall utilize fully dynamic modeling techniques for all line sections or nodes within the selected DPA. <u>This demonstration shall consider two scenarios:</u> i. The DER capacity does not cause power to flow beyond the substation busbar. ii. The DERs technical maximum capacity is considered irrespective of power flow toward the transmission system.	9. Demonstrate Dynamic ICA using Two DER Scenarios including No Backflow and Maximum DER Capacity Irrespective of Power Flow Direction

Discussion of Section 1.a.ii of the ICA Guidance

The utilities point out that their ICA methodologies take into account existing DER deployment as well as capacity increases that may occur over the next two years. The Commission agrees with this assertion and believes that the utilities have complied with this requirement of this section of the DRP Guidance in their DRP filings.

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[4] ACR attachment, Section 2, subsection a, p. 6

The utilities have stated that peak load and DER growth over the next two years is reflected in the load forecasting process they use for distribution planning. They use the results of load forecasting to develop peak and minimum load on each circuit that is used for the ICA. The ICA methodology requirements described in this attachment require the IOUs to use a transparent method for both load forecasting and DER growth in their ICA calculation methodology. DER growth scenarios will be approved in a separate Commission action. For purposes of both load forecasting and DER growth scenarios, Demonstration Project A shall be conducted using the following scenarios:

- 2-year growth scenario as required in the Guidance and described above;[5] and
- Growth scenarios I and III as proposed in the DRP Applications.
- Each scenario shall be conducted in two different DPAs that are selected to represent the range of physical and electrical conditions within the respective IOU distribution systems.

1.2 Discussion of Use of Modified "Baseline" IOU ICA Methodology Proposal in Demonstration A

As required by the Commission, each IOU proposed an ICA methodology and an initial scope to be addressed at the time of the Application filing.

A common finding that all three utilities observed in their Applications is that DER integration or hosting capacity increases with:

- Lower distribution line impedance or lower distance from the substation;
- Higher distribution operating voltage; and

[5] DRP Guidance section 1.a.ii., at 3.

- Higher minimum loading.

The three IOUs' proposed ICA methodologies differ in significant ways. Based on a review of the three proposals, it is reasonable that a "baseline" methodology derived from PG&E's approach can be modified to address methodological deficiencies. The baseline methodology defined in this attachment shall form the standard upon which all three IOUs shall base their common ICA methodology. This Ruling finds that such a "baseline" ICA methodology with modifications can be used in the Demonstration Project A. The IOUs are directed to adopt the modified ICA methodology described herein, with the recognition that increased transparency and uniformity is essential as the methodology is further developed in the Demonstration A projects and ICA Working Group. Completion of the Demonstration A project is a developmental step towards IOU final proposals for a common ICA methodology across all IOUs that can be used to update the DER hosting capacity at regular intervals. Such approval of final ICA methodology is anticipated by the DRP Scoping Memo to occur in early 2017.

Demonstration Project A should commence immediately for all IOUs using the "baseline" IOU ICA proposal modified according to this Ruling.

1.3 Overview of Baseline ICA Methodology Steps[6]

The ICA methodology contains four general steps, based on a so-called "streamlined" hosting capacity analysis.[7] The IOUs are directed to base their ICA methodology on the following four steps.

1. **Establish distribution system level of granularity** - Analysis shall be performed down to specific nodes within each line section of individual

[6]This methodology is adapted from the PG&E ICA proposal in its DRP filing (A.15-05-006 at p23).
[7] PG&E DRP Application at 23

distribution feeders. Nodes shall be selected based on impedance factor, which is the measure of opposition that a circuit presents to electric current on application of voltage. Minimum and maximum (i.e. best and worst case) ranges of results shall be evaluated using lowest and highest impedance.

2. **Model and extract power system data** – A Load Forecasting Analysis Tool (e.g. Load SEER) shall be used to develop load profiles at feeder, substation and system levels by aggregating representative hourly customer load and generation profiles.[8] Load profiles shall be created for each DPA. The load profiles are comprised of 576 data points representing individual hours for the 24-hour period during a typical low-load day and a typical high-load day for each month (2 days * 24 hrs * 12 months = 576 points). A Power Flow Analysis Tool (e.g. CYMEDist for PG&E and SCE and Synergi Electric for SDG&E) shall be used to model conductors, line devices, loads and generation components that impact distribution circuit power quality and reliability. The Power Flow Analysis Tool shall be updated with the latest circuit configurations based on changes to the GIS asset map per the current practice of each utility.

3. **Evaluate power system criterion to determine DER capacity** – The Load Forecast Tool and Power Flow Analysis Tool shall be used to evaluate power system criterion for the nodes and line sections that determine DER capacity limits on each distribution feeder. ICA results are dependent on the most limiting power system criteria. This could be any one of the

[8] LoadSEER is the name of a commercial utility load forecasting product marketed by Integral Analytics.

factors listed in PG&E's Table 2-4 in their DRP Application under "Initial Analysis" and summarized below[9]:

a. Thermal Criteria – determined based on amount of additional load and generation that can be placed on the distribution feeder, without crossing the equipment ratings.

b. Power Quality / Voltage Criteria – voltage fluctuation calculated based on system voltage, impedances and DER power factor. Voltage fluctuation of up to 3% is part of the system design criteria for all three utilities.[10]

c. Protection Criteria – determined based on required amount of fault current fed from the sub-transmission system due to DER operation. This is an area that the Working Group shall further develop. A potential starting point is the approach of PG&E as follows: Reduction of reach concept for generators was used with 10% evaluation as a flag for issues with the protection schemes. PG&E assumes that DER inverters contribute 120% rated current compared to 625% rated current from synchronous machines for a short circuit on the terminals.

d. Safety/Reliability Criteria – determined based on operational flexibility that accounts for reverse power flow issues when DER/DG is generating into abnormal circuit operating scenarios.

[9] PG&E DRP Application at 33.

[10] SCE limits DER hosting capacity to ensure there is no overvoltage on the primary voltage of the distribution circuits. SDG&E limits voltage fluctuation at all points on the feeder to 3%, similar to PG&E. The 3% value is typically used by international utilities for limiting the size of capacitor banks which may be switched a few times each day. IEC/TR 61000-3-7 2008 'Electromagnetic Compatibility (EMC) Part 3-7: Limits Assessment of Emission Limits for the Connection of Fluctuating Installations to MV, HV, and EHV Power Systems', Table 6 suggests indicative planning levels on medium voltage systems of 3% step voltage for changes occurring 2-10 times per hour.

Other limitations supporting the safe and reliable operation of the distribution system apply.

4. **Calculate ICA results and display on online map -** The ICA calculations shall be performed using a layered abstraction approach where each criteria limit is calculated for each layer of the system independently and the most limiting values are used to establish the integration capacity limit. The ICA calculations shall be performed in a SQL[11] server database or other platform as required for computation efficiency purposes. The resulting ICA data shall be made publicly available using the Renewable Auction Mechanism (RAM) Program Map. The ICA maps shall be available online and shall provide a user with access to the results of the ICA by clicking on a feeder displayed on the map. For the purposes of Demonstration Project A, the current utility map displays shall be used until further direction on a common approach is provided by the Commission.[12]

1.4 Specific Modifications to Include in Baseline Methodology

The IOUs are directed to modify the baseline ICA analysis method described above in Section 1.3. The requirements are organized according to the nine technical requirements mapping to the Guidance Ruling shown above in Table 1.

1. <u>Quantify the Capability of the Distribution System to Host DER</u>

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[11] SQL is a standard database technology.

[12] See http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/index.page The online DER hosting map published by SDG&E allows users to select any feeder and identify the hosting capacity for each zone on the feeder. SDG&E also prominently displays the sum of the hosting capacities of all the feeders.

a. Devices that contribute to reactive power on the circuit (e.g. capacitors, etc.) and their effect on the power flow analysis shall be included in the power flow model.

b. Power flow analysis shall be calculated across multiple feeders, whenever feasible for more accurate ICA values. All feeders that are electrically connected within a substation shall be included in this analysis.

c. The ICA shall be modified to reflect DERs that reduce or modify forecast loads. SDG&E has stated that "load modification strategies can be incorporated in the ICA by modifying the underlying power flow case to reflect the reduction in load."[13]

d. Disclose any unique assumptions utilized to customize the power flow model of each IOU and all other calculation that could impact the ICA values.

2. <u>Common Methodology Across All IOUs</u>

a. The "baseline" methodology with modifications described in this ruling will be used as a provisional common ICA methodology used by all IOUs in the Demonstration A Projects. At this time, SCE and SDG&E are required to adopt the modified baseline methodology described in this ruling, which is derived from PG&E's basic methodology. SCE and SDG&E's power flow analysis and load forecast tool methodologies should be adapted, as required, using PG&Es methodology as the basis.

3. <u>Different Types of DER</u>

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[13] "Comments And Responses To Questions Of San Diego Gas & Electric Company (U 902-E)" p. 6

a. The methodology shall evaluate the capacity of the system to host DERs using a set of 'typical' DER operational profiles. PG&E has developed a set of profiles that provide a starting point. [14] These profiles are:
    - Uniform Generation
    - PV
    - PV with Tracker
    - EV – Residential (EV Rate)
    - EV – Workplace
    - Uniform load
    - PV with Storage
    - Storage – Peak Shaving
    - EV – Residential (TOU rate)

b. ICA shall quantify hosting capacity for portfolios of resource types using PG&E's approach with representative portfolios of
    i. solar,
    ii. solar and stationary storage,
    iii. solar, stationary storage, and load control and
    iv. solar, stationary storage, load control, and EVs.

c. Utilities shall propose a method for evaluating DER portfolio operational profiles that minimize computation time while accomplishing the goal of evaluating the hosting capacity for various DER portfolios system-wide.

[14] PG&E DRP Application 15-07-006 at 49, figure 2-18.

For example, a mix of storage, PV, and demand response could be characterized as the "most likely" to be deployed in a specific area. This could be used as a baseline portfolio, which would be used to calculate the ICA.

d. The ICA Working Group shall identify additional DER portfolio combinations.

4. **Granularity of ICA in Distribution System**

a. Locational granularity of ICA is defined as line section or node level on the primary distribution system, as specified in the PG&E methodology.

5. **Thermal Ratings, Protection Limits[15], Power Quality (including Voltage), and Safety Standards**

a. Include all the different types of defined power system criteria and sub-criteria in the analysis. [16]

   i. In Table 2-4 in its DRP application, PG&E has indicated a set of power system criteria to be used in a "Potential Future Analysis." All items on this list should be incorporated to the extent feasible initially, with the objective of complete inclusion as the capabilities become available.

b. Protection Limits used in ICA – The IOUs shall agree upon on a common approach to representing protection limits in the ICA. [17]

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[15] Protection limits refer to the limits defined in the standards, recommended practices and guides utilized by the IOUs regarding the application, design, construction and operation of protective, regulating, monitoring, reclosing, synch-check, synchronizing and auxiliary relays or switches in order to protect power system components against damage and failure. (Standards Association Power Systems Relay Committee)

[16] PG&E indicates the list of Power System Criteria included in its initial analysis in Table 2-4 at 33. For example, Service Transformers, Secondary Conductors and Transmission Lines are not included in the initial analysis, but are included as "Potential Future Analysis." To the extent possible, all power system criteria in all categories in this table should be included.

c. Utilities shall provide documentation to describe the ICA limit criteria and threshold values and how they are applied in the Demonstration A Projects, in an intermediate status report, due Q3 2016.[18]

d. Utilities shall provide documentation to identify and explain the industry, state, and federal standards embedded within the ICA limitation criteria and threshold values, and include this in Final Report due early Q4 2016.[19]

e. Included with ICA results for each feeder provide
   i. Feeder-level loading and voltage data,
   ii. Customer type breakdown,
   iii. Existing DER capacity (to the extent not already available).

f. Identify feeders where sharing the information in paragraph "e" violates any applicable data sharing limitations.

g. ICA results should include detailed 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 shall be in a downloadable format and with sufficient detail to allow customers and DER providers to design portfolios of DER to overcome the constraints. This information may include relevant load and voltage

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[17] Utilities currently have different approaches to implementing protection limits in their methodologies. In order to comply with the Guidance Ruling requirement to consider protection system limits, the IOUs must agree on a common approach to handling protection limits in the methodology.
[18] As proposed by ORA in Comments on ICA Methodologies, ICA Workshop Report, Locational Net Benefits Analysis and Demonstration Projects A and B filed March 3, 2016 at A-1.
[19] Ibid. at A-2.

profiles, reactive power requirements, or specific information related to potential system protection concerns.[20]

6. **Publish the Results via Online Maps**

   a. 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 shall also be available in a standard shapefile format, such as ESRI ArcMap Geographic Information System (GIS) data files.[21] The maps and associated materials and download formats shall be consistent across all utilities and should be clearly explained through the inclusion of "keys" to the maps and associated materials. Explanations and the meanings of the information displayed shall be provided, including any relevant notes explaining limitations or caveats. Any new data types developed in the ICA working group shall be published in a form to be determined in the data access portion of the proceeding.

   b. Existing RAM map information and ICA results shall be displayed on the same map. RAM information shall be the default information displayed on that map with ICA data available if the user specifies it.[22]

7. **Time Series or Dynamic Models**

   a. ICA shall utilize a dynamic or time series analysis method as specified in the Guidance.[23] This analysis shall be consistent among the three IOUs.

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[20] Parties have expressed concern that the information currently available is not sufficient to determine how a DER can be deployed at lowest cost at any given location.

[21] The ESRI ArcMap "shapefile" is one of the current standards for GIS data. This is the preferred format, although other standards exist.

[22] "Default information" refers to the data that is displayed on the "first click" or as the data that is immediately accessible without further specification or selection setting.

[23] A dynamic analysis as specified in the Guidance is also known as a "time series analysis." This power flow analysis technique uses hourly load and generator output profile data to simulate the operation of the generator over all 8,760 hours of the year.

The IOUs currently use different power flow analysis tools that may implement a time series analysis differently. The methodology used by the three IOUs should therefore be based on capabilities that are common among the tools that support a consistent result.[24] IOUs shall consult with the ICA working group to ensure that the power flow analysis tools use an equivalent approach to dynamic or time series analysis.

8. **Avoid Heuristic approaches, where possible**

   a. There are no new modifications based on this Guidance requirement.[25]

2. Approved Demonstration Project A

The IOUs' Demonstration Project A proposals are approved as modified below.

Demonstration Project A Power Flow Scenarios

The Guidance Ruling required the IOUs to model two scenarios in their Demonstration A projects:

a. The DER capacity does not cause power to flow beyond the substation busbar.

b. The DERs technical maximum capacity is considered irrespective of power flow toward the transmission system. [26]

The IOUs DRP Applications included the "no reverse flow at the substation" scenario, but the IOUs did not include the second scenario to consider the

[24] The Power Flow Analysis tools used by the utilities have not traditionally supported time series analysis. The tools were used to model a single load point that represented the peak load on the circuit. The capability to simulate hourly power flows on the line section under study are relatively new, and are just beginning to be used by utilities. As different analysis tools may implement this capability differently, further study is required to ensure that the three IOUs are utilizing this capability in a uniform fashion. This is a topic that shall be further examined in the Working Group.

[25] A heuristic approach is one involving or serving as an aid to learning, discovery, or problem-solving by experimental and especially trial-and-error methods.

[26] DRP Guidance ACR at 6

"maximum DER capacity irrespective of power flow direction beyond the substation". It is important to understand the potential for hosting capacity irrespective of power flow concerns to understand the trade-offs between the benefits of additional IC and the potential impacts of reverse power flow on the system. Consequently, the IOUs are reminded that they need to conduct the ICA using both scenarios.

Demonstration A Project Schedule

Demonstration A project schedules proposed in IOU Applications are modified and shall commence immediately with the issuance of this Ruling. The revised schedule is further discussed below.

Demonstration A Project Locations

Demonstration A project locations proposed in the Applications are modified and shall 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 shall clarify 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 shall also justify in their detailed plans the basis for choosing each DPA for the Demonstration Projects.

Demonstration A Project Detailed Implementation Plan

The IOUs shall submit detailed implementation plans for project execution, including metrics, schedule and reporting interval. To the extent practicable, the IOUs shall consult with the ICA working group on the development of the plan. The plan shall be submitted to the CPUC within as a status update within 90 days of this ruling and served to the R.14-08-013 service list. The ICA Demo A Plan shall include:

a. Documentation of specific and unique project learning objectives for each of 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.[27]
    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 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 the Demonstration A project: 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

[27] As ORA point out, for example, if ICA development relies on SCADA build out or development of modeling or forecasting tools, these should be included.

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.

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.[28]

3. ICA Working Group

An ICA working group, which shall be modeled on the Smart Inverter Working Group and the More Than Smart working group, is established to monitor and provide consultation to the IOUs on the execution of Demonstration Project A and further refinements to ICA methods. The working group shall be open to the public and informal in nature. Energy Division staff will have oversight responsibility of the working group, but it shall be managed by the utilities and interested stakeholders on an interim basis. The Energy Division may at its discretion assume direct management of the working group or appoint a working group manager. The working group serves two main purposes:

1. Monitor and Support Demonstration Project A
2. Continue to improve and refine the ICA methodology

The activities are organized by (I) short-term work related to the Demonstration Project A and improvements to ICA that could be adopted in a Q1 2017 ICA

[28] Attachment D, ORA ICA Workshop Presentation November 10, 2015, Slides 12 and 13, filed in Comments Of The Office Of Ratepayer Advocates On The ALJ Ruling Inviting Comments On Integration Capacity Analysis (ICA) Methodologies, ICA Workshop Report, Locational Net Benefits Analysis (LNBA)Workshop And Demonstration Projects A And B.

Decision and (II) longer-term work related to ongoing refinements to ICA methodology beyond that time frame conducted in parallel, but not directly related, to the Demonstration Project A. Short term work should be addressed by the time of the submittal of the final Demonstration A report. Longer-term work may be addressed in the final report and may continue beyond the timeframe of Demonstration Project A. A detailed schedule is provided below.

3.1 ICA Working Group Activity related to Demonstration Project

a. Update schedule for Demo A results.

b. Recommend methods for evaluation of hosting capacity for the following resource types:

    i. DER bundles or portfolios, responding to CAISO dispatch;

    ii. Facilities using smart inverters.

c. Recommend a format for the ICA maps to be consistent and readable to all California stakeholders across the utilities' service territories with similar data and visual aspects (color coding, mapping tools etc).

d. Evaluate and recommend new methods that may improve the computational efficiency of the ICA tools and process in order to calculate and update ICA values across all circuits in each utility's service territory in updated ICAs more frequently and accurately.

e. Evaluate ORA's recommendation to require establishment of reference circuits and reference use cases for comparative analyses of Demonstration Project A results.[29]

f. Establish a method for use of Smart Meter and other customer load data to develop more localized load shapes to the extent that is not currently being done.

[29] Ibid, at 7.

g. Establish definite timelines for future achievement of ICA milestones including frequency and process of ICA updates

3.2 ICA Working Group Activity related to continued refinements to ICA methodology.

The working group shall consult to the IOUs on continued advancement and improvement of the ICA methodology. The following topics are a suggested list:

a. Expansion of the ICA to single phase feeders;
b. Ways to make ICA information more user-friendly and easily accessible (data sharing);
c. Interactive ICA maps;
d. Market sensitive information (type and timing of the thermal, reactance, or protection limits associated with the hosting capacity on each line);
e. Method for reflecting the effect of potential load modifying resources on integration capacity;
f. Development of ICA validation plans, describing how ICA results can be independently verified;
g. Definition of quality assurance and quality control measures, including revision control for various software and databases, especially for customized or "in-house" software;

This Working Group will have the following schedule:

Convened by the utilities within 10 days of the date of this ruling	Q2 2016
Project Plan filed within 45 days of the date of this ruling	Q2 2016
Meet monthly to monitor Demonstration	Q2, Q3, Q4 2016

Project A	
Final Demonstration A Report –Energy Division may provide further guidance on the content and format of the report.	Q4 2016
First Intermediate Status Report on Long-Term ICA Refinement	Q4 2016
Final Report on Long-Term ICA Refinement	Q2 2017

3.3 PG&E Demonstration A Requirements

1. PG&E shall clarify reasoning for selection of Fresno Distribution Planning Area as the site for conducting one of the Demonstration Project A sites for the Commission approved ICA methodology.[30]
2. PG&E shall continue to improve computational efficiency of its batch processing under the Demo A Project.[31] Such techniques shall be shared in the working group as they are developed.

3.4 SCE Demonstration Project A Requirements

1. SCE shall clarify reasoning for selection of an "A" level substation within Orange County as the site for conducting one of the Demo Project A sites for the Commission approved ICA methodology.[32]

[30] PG&E does not indicate any particular reason why Fresno DPA was selected over other DPAs. Typically, the selection of a demonstration site includes the reasons for selection like high forecasted load growth, commercial and industrial customer penetration, renewable penetration, or proximity to larger transmission substations, etc. PG&E indicates the total substation loading capacity is 491 MW and the forecasted load is 490 MW in 2020. This doesn't seem to be supportive as a selection criterion for Fresno DPA.

[31] This is an important step to determine a timely ICA process which can be conducted for the DPA and can be replicated for all DPAs within practical time constraints due to computational limitations.

2. SCE shall streamline its ICA process to utilize batch processing similar to PG&E's ICA process.[33]

3.5 SDG&E Demonstration Project A Requirements

1. Improved Granularity – SDG&E shall improve the granularity of the analysis to line section or node level, similar to PG&E's methodology where feeders are divided into segments based on appropriate line devices.[34]
2. Dynamic Modelling – SDG&E shall expand their analysis to cover each hour of the year or propose an alternative temporal granularity.[35] SDG&E shall provide specific details on the nature of dynamic analysis they plan to conduct during the demonstration.[36]
3. DER Categories – SDG&E shall include all categories of DER, as defined in this ruling.[37]

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[32] SCE does not indicate any particular reason why the Orange County "A" level substation was selected over other DPAs.

[33] SCE added generation values at various points on their representative circuits to estimate integration capacity. SCE does not provide information on the plan to streamline batch processing, not only for the proposed DPA, but for all the 4000+ circuits in their service territory.

[34] SDG&E divides each backbone feeder into 3 zones based on line impedance to the substation. This does not meet the Guidance Ruling requirement for analysis down to line section or node level. SDG&E then calculated their ICA for each zone by first setting the DER injection to equal the load on the feeder, resulting in zero feeder flow at the substation. SDG&E then did a power flow analysis to check whether any equipment nameplate thermal ratings, feeder voltage limits, voltage fluctuation limits and protective devices' fault current ratings were breached. If any limit was breached, then the DER injection was reduced by 0.5 MW decrements until an acceptable power flow result was obtained.

[35] SDG&E's ICA methodology presently considers only maximum and minimum daytime load on each feeder as they are focused on PV inverters.

[36] SDG&E's ICA considers maximum and minimum daytime load on each feeder as they are focused on PV inverters. Staff considers that this does not meet the Guidance Ruling requirement for dynamic time series modelling throughout the day. SDG&E indicated that they will eventually conduct an analysis for each hour of the year, as is done by PG&E.

[37] SDG&E focused on PV inverters which does not meet the Guidance Ruling requirement for considering all forms of DER. SDG&E indicated that they will eventually consider other forms of DER, as is done by PG&E. The Guidance Ruling requires that a number of different categories of DER are considered, including PV, wind, fuel cell, CHP, IC engines, energy efficiency, energy storage, electric vehicles, and demand response. SDG&E presently focuses on PV installations which are the fastest growing type of DER in their system.

4. LNBA Methodology and Demonstration Project B

4.1 Background

The Guidance describes an Optimal Location Benefit Analysis (referred to in this document as LNBA) to specify net benefits that DERs can provide at any given location. The utilities were directed to develop a common locational net benefits methodology based on the Commission-approved E3 cost effectiveness calculator (Distributed Energy Resource Avoided Cost Calculator or DERAC).[38] The Guidance specified that value components in this framework that were not location-specific, such as energy or capacity, be modified to reflect more location-specific information. For example, values such as LMP-specific avoided energy costs, and avoided local resource adequacy procurement could be used instead of system-wide values.

The staff proposal made a distinction between the non-location specific value components that reflect "system level" conditions of the bulk electric system (e.g., system Resource Adequacy, energy, avoided GHG, etc.) and location-specific values that reflect "local level" conditions of the distribution system. Accordingly, the value components listed below in **bold** are the primary focus of the DRP proceeding. The other system level value components are being deferred to the IDER proceeding, per the Roadmap staff proposal.[39, 40] Per the Guidance, the LNBA would include the following value components not currently included in the DERAC:

- **Avoided Sub-transmission, Substation and Feeder Capital and Operating Expenditures**

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[38] https://www.ethree.com/documents/DERAvoidedCostModel_v3_9_2011_v4d.xlsm
[39] IDER proceeding R. 14-10-003
[40] DRP Roadmap Staff Straw Proposal at 18

- **Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures**
- **Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures**
- **Avoided Transmission Capital and Operating Expenditures**
- Avoided Flexible Resource Adequacy (RA) Procurement
- Avoided Renewables Integration Costs
- Any societal non-energy avoided costs which can be clearly linked to the deployment of DERs, such as environmental or public safety avoided costs.[41]

In addition to proposing an LNBA methodology, the Guidance required the IOUs to specify a demonstration project ('Demonstration Project B') where the approved LNBA methodology is performed for one DPA, including a detailed implementation schedule. In selecting which DPA to study, the IOUs were instructed to, at minimum, 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.[42] This guidance ruling expands the scope of the Demonstration Project B to require demonstration of at least one voltage support/power quality- or reliability/resiliency-related deferral opportunity in addition to one or more capacity-related opportunities. Both types of opportunities may be located in the same DPA, but if the DPA selected by any IOU does not include noncapacity-related opportunities, the IOU must evaluate a noncapacity project in another DPA.

[41] Ibid at 4
[42] Guidance Ruling at 6

4.2 IOU Proposals for LNBA Methodology

In their DRP applications, the IOUs incorporated the direction of the Guidance to employ a "Commission approved E3 Cost-Effectiveness Calculator, but enhanced to explicitly include location-specific values." They proposed a modified version of the E3 Distributed Resource Avoided Cost Calculator (DERAC) as a basic framework.

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 <u>four</u> 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.

4.3 Approved LNBA Methodology for Demonstration B

Table 2 below summarizes the approved LNBA methodology framework for Demonstration B. The approach is to specify a primary analysis that the IOUs shall execute and a secondary analysis that the IOUs may execute in addition to the required analysis. Consistent with the Roadmap staff proposal, the primary analysis shall use DERAC values, if available, for system-level values. For the primary analysis, the IOUs are directed to develop certain system-level values that are not yet included in the DERAC (e.g., Flexible RA, renewables integration costs, etc.) to the extent feasible. The primary analysis shall execute location-specific methodologies for avoided T&D cost, generally as proposed by the IOUs in their applications but with certain modifications. The secondary analysis acknowledges the potential utility of having additional LNBA results produced using system-level values as proposed by the IOUs in their applications. While the secondary analysis generally does not conform to currently approved CPUC methodologies, the IDER proceeding may benefit from having these supplemental results as it reviews common cost effectiveness methodologies. Given time constraints, however, the secondary analysis is considered optional at the discretion of the IOU. If an IOU chooses to execute a secondary analysis in the Demonstration B, the results shall comprehensively include all of the value parameters specified for it in Table 2.

Table 2 Approved LNBA Methodology Requirements Matrix for Demonstration Project B.

Components of avoided costs	Proposed LNBA in IOU Filings	Primary Analysis	Secondary Analysis
from DERAC	*from IOU applications*	*Required*	*Optional additional*
Avoided T&D	**Sub-Transmission / Substation / Feeder**	**As proposed but with modifications (1)**	**As proposed but with modifications (1)**
	Distribution Voltage / Power Quality	**As proposed but with modifications (1)**	**As proposed but with modifications (1)**
	Distribution Reliability / Resiliency	**As proposed but with modifications (1)**	**As proposed but with modifications (1)**
	Transmission	**As specified herein (2)**	**As specified herein (2)**
Avoided Generation Capacity	System and Local RA	Use DERAC values	Use DERAC values with location-specific line losses (3)
	Flexible RA	Use DERAC	Use DERAC values

		values with flexibility factor (4)	with flexibility factor (4)
Avoided Energy	Use LMP prices to determine	Use DERAC values	As proposed but with modifications regarding use of LMP prices (5) and location-specific losses (3)
Avoided GHG	incorporated into avoided energy	Use DERAC values	As proposed
Avoided RPS	similar to DERAC	Use DERAC values	As proposed
Avoided Ancillary Services	similar to DERAC	Use DERAC values	As proposed
additional to the DERAC	Renewable Integration Costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)
	Societal avoided costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)
	Public safety costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)

Table notes:

(a) "As proposed" means per IOU proposals in their DRP applications or as subsequently clarified in post-workshop comments.

(b) Numbers in parentheses correspond to specific modifications detailed, as numbered, in section 3.4.

4.4 Required Modifications to LNBA Methodology

The required modifications below correspond to the parenthetical numbers in the table above. They are organized into LNBA-specific requirements (3.4.1) and other related LNBA requirements (3.4.2).

4.4.1 LNBA-specific requirements

(1) The IOUs shall use the following method for evaluating **sub-transmission / substation / feeder, distribution voltage, and distribution reliability-related services and associated avoided costs** in Demonstration Project B:

(A) The IOUs shall identify the full range of electric services that result in avoided costs for <u>all</u> locations within the DPAs selected for analysis. The values shall include any and all electrical services associated with distribution grid upgrades identified in (i) the utility distribution planning process, (ii) circuit reliability improvement process and (iii) maintenance process.

(B) The evaluation method must conform to the following specifications:

i. Develop a list of locations where upgrade projects, circuit reliability, or maintenance projects may occur over each of the planning horizons specified in (B)(iii) below, to the extent possible.

ii. Use existing approaches for estimating costs of required projects identified in the processes in (A) above.

iii. System upgrade needs identified in the processes in (A) above should be 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) or other time ranges, as appropriate and that correspond to current utility forecasting practice. A fourth category may be created employing "ultra-long-term forecast" greater than 10 years to the extent that such a time frame is supported in existing tools.

iv. Prepare a location specific list of electric services associated with the planned distribution upgrades, and present these electric service needs in machine readable and map based formats.

v. For all electrical services identified, identify DER capabilities that would provide the electrical service. As a starting point, consider all DER derived from standard and 'smart' inverters and synchronous machines.

vi. Prepare a specification including:

  (a) A description of the various needs underlying the distribution grid upgrades;

  (b) Electrical parameters for each grid upgrade including total capacity increase, real and reactive power management and power quality requirements;

  (c) An equipment list of components required to accomplish the capacity increase, maintenance action or reliability improvement.

  (d) Project specifications for reliability, maintenance or capacity upgrade projects identified by the utilities shall include specifications of the following services as applicable:

    (I) Voltage Control or Regulation

    (II) Reactive Supply

    (III) Frequency Regulation

    (IV) Other Power Quality Services

    (V) Avoided Energy Losses

    (VI) Equipment Life Extension

    (VII) Improved SAIFI, SAIDI and MAIFI results

(vii) Compute a total avoided cost for each location within the DPA selected for analysis, per the following guidance:

(a) Use the Real Economic Carrying Charge method to calculate the deferral value of these projects, as described in SCE's application.

(b) Assign these costs to the four avoided cost categories in the DERAC calculator for this location.

(c) Use forecast horizons consistent with paragraph (1)(B)(iii) above to identify areas of capacity need.

(C) To the extent that DER can provide distribution system services, the location of such needs and the specifications for providing them should be indicated on the LNBA maps. This analysis shall include opportunities for conservation voltage reduction and volt/VAR optimization. Additional services may be identified by the Working Group.

(2) For avoided costs related to **transmission capital and operating expenditures**, the IOUs shall, to the extent possible, quantify the co-benefit value of ensuring (through targeted, distribution-level DER sourcing) that preferred resources relied upon to meet planning requirements in the California ISO's 2015-16 transmission plan, Section 7.3,[43] materialize as assumed in those locations. The IOUs shall provide work papers with a clear description of the methods and data used.

[43] https://www.caiso.com/Documents/Draft2015-2016TransmissionPlan.pdf. See pp 333-337 for a complete list of specific locations.

(A) If the IOUs are unable to quantify this value, they should use the avoided transmission values in the Net Energy Metering (NEM) Public Tool developed in R. 14-07-002.[44]

(3) For the secondary analysis, use the DERAC **avoided capacity and energy values modified by avoided line losses** may be based on the DER's specific location on a feeder and the time of day profile (not just an average distribution loss factor at the substation).[45] The IOUs shall provide a clear description of the methods and data used.

(4) For the avoided cost of generation capacity for any DERs which provides **flexible generation**, the IOUs shall apply a method, such as the "F factor" which has been proposed for the Demand Response Cost-effectiveness Protocols.[46] The IOUs shall provide work papers with a clear description of the methods and data used.

(5) For the secondary analysis, the IOUs may also estimate the **avoided cost of energy using locational marginal prices (LMPs)** for a particular location, as per the method described in SCE's application. The IOUs shall provide work papers with a clear description of the methods and data used.

(6) If values can be estimated or described related to the **avoided costs of renewable integration, societal (e.g., environmental) impacts, or public safety impacts**, the IOUs shall propose their methods for including these

[44] The NEM Public Tool is available at: http://www.cpuc.ca.gov/General.aspx?id=3934.
[45] Based on Energy Division Staff analysis.
[46] SCE AL 3386-E (et al) filed March 29, 2016, pursuant to OP 8 of D.15-11-042.

values or descriptions in the detailed implementation plans required in Section 6 below.

(7) The IOUs shall provide detailed descriptions of the method used, with a clear description of the modeling techniques or software used, as well as the sources and characteristics of the data used as inputs.

(8) The IOUs shall provide access to any software and data used to stakeholders, within the limits of the CPUC's confidentiality provisions. Both the primary and secondary analyses should use the load shapes or adjustment factors appropriate to each specific DER.

4.4.2. Other related LNBA requirements

(1) The IOU's LNBA results shall be made available via heat map, as a layer along with the ICA data in the online ICA map. The electric services at the project locations shall be displayed in the same map format as the ICA, or another more suitable format as determined in consultation with the working group. Total avoided cost estimates and other data may be also be required as determined in the data access portion of the proceeding.

(2) The IOUs shall execute and present their LNBA results under two DER growth scenarios: (a) the IEPR trajectory case, as filed in their applications (except that PG&E shall conform its PV forecast to the IEPR base case trajectory); and (b) the very high DER growth scenario, as filed in their applications.

   a. The DER growth scenario used in the distribution planning process for each forecast range should be made available in a heat map form as a layer in conjunction with the ICA layers identified earlier.

5. Approved Demonstration Project B

The IOUs' Demonstration Project B proposals are approved, as modified below.

5.1. General Requirements for all IOUs

a. The IOUs shall select one or more DPAs that will enable a range of capacity, reliability improvement, and power quality requirements to be addressed.

b. As noted in Section 3.3.1 above, the projects included for LNBA assessment shall include all capacity expansion, reliability improvement and maintenance projects in the deferral project candidate list.

c. The IOUs shall identify whether the following equipment investments can be deferred or avoided in these projects by DER: (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. The IOUs shall submit **detailed implementation plans** for project execution, including metrics, schedule and reporting interval. To the extent practicable, the IOUs shall consult with the LNBA working group on the development of the plan. The plan shall be submitted to the CPUC within 45 days of this ruling. The implementation plan shall include:

    i. A detailed description of the revised LNBA methodology that conforms to the guidance in Section 3.4 above.

    ii. A description of the load forecasting or load characterization methodology or tool used to prepare the LNBA;

iii. A schedule/Gantt chart of the LNBA development process for each utility, showing:

    i. Any external (vendor or contract) work required to support it.[47]

    ii. Additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested;

    iii. Any additional resources required to implement Project B not described in the Applications;

iv. 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 the Demonstration B project: 1) an intermediate report; and 2) the final report.

6. LNBA Working Group

An LNBA working group, which shall be modeled on the Smart Inverter Working Group and the More Than Smart working group, is established to monitor and provide consultation to the IOUs on the execution of Demonstration Project B and further refinements to LNBA methods. Energy Division staff will have oversight responsibility of the working group, but it shall be managed by the utilities and interested stakeholders on an interim basis. The Energy Division may at its discretion assume direct management of the working group or appoint a working group manager. The working group serves four main purposes:

[47] As ORA point out, for example, if ICA development relies on SCADA build out or development of modeling or forecasting tools, these should be included.

1. Monitor and Support Demonstration Project B
2. Continue to improve and refine the LNBA methodology
3. Coordinate with IDER system-level valuation activities of the IDER cost-effectiveness working group
4. Coordinate with the IDER solicitation framework working group where objectives may overlap (e.g., the definition and description of grid deficiencies vs. DER performance requirements and contractual terms needed to ensure DERs meet the identified grid deficiencies)

The activities are organized by (I) short-term work related to the Demonstration Project B and improvements to LNBA that could be adopted in a Q1 2017 Decision and (II) longer-term work related to ongoing refinements to LNBA methodology beyond that time frame conducted in parallel, but not directly related, to the Demonstration B. Short term work should be addressed by the time of the submittal of the final Demonstration B report.

6.1 Activity related to Demonstration Project B

a. Recommend a format for the LNBA maps to be consistent and readable to all California stakeholders across the utilities' service territories with similar data and visual aspects (color coding, mapping tools etc.).

b. Consult to the IOUs on further definition of grid service, as described in requirement (1)(B)(iv-v) of Section 4.3.1 above, and in coordination with IDER proceeding.

6.2 Activity related to Continuing Refinements to LNBA

(1) Continue advancement and improvement of the LNBA methodology. The working group shall consult to the IOUs on:

(A) Methods for evaluating location-specific **benefits over a long term horizon** that matches with the offer duration of the DER project. For example, there may be economic benefits in deferring network augmentations in the far future; however the benefits are likely to be discounted due to uncertainty. This work should explore whether / how probability estimates, based on the utility's past and current distribution planning experience, could be made that (1) an as-yet undetected need for upgrades will be required during the distribution planning period and (2) procurement of DERs that have a timescale greater than the distribution planning period will avoid future upgrades subsequent to the distribution planning period.

(B) Methods for valuing location-specific **grid services provided by advanced smart inverter capabilities**. Examples include the following seven smart inverter functions identified by the Smart Inverter Working Group[48] : (i) DER Disconnect and Reconnect Command, (ii) Limit Maximum Real Power Mode, (iii) Set Real Power Mode, (iv) Frequency-Watt Emergency Mode, (v) Volt-Watt Mode, (vi) Dynamic Reactive Current Support Mode, and (vi) Scheduling power values and modes

[48] Marc Monbouquette, 'Categorizing Distribution-Level Avoided Costs Due to Utilization of Smart Inverter Phase 3 Functions', Presented at the Locational Benefits Analysis Workshop, (R.14-08-013), February 1 2016.

(C) Consideration, and if feasible, development of, **alternatives to the avoided cost method, such as distribution marginal cost or other methods**.[49]

(D) The IOUs shall determine a method for evaluating the effect on avoided cost of DER working "in concert" in the same electrical footprint of a substation. Such DER may complement each other operationally using a distributed energy resource management system (DERMS).

This Working Group will have the following schedule:

Convened by the utilities within 10 days of the date of this ruling	Q2 2016
Implementation Plan filed within 45 days of this Ruling	Q2 2016
Meet monthly to monitor Demonstration Project B. Utilities to provide monthly briefing.	Q2, Q3, Q4 2016
Final Report –Energy Division may provide further direction regarding the content and format of the report.	Q4 2016
First Intermediate Status Report on Long-Term LNBA Refinement – File 180	Q4 2016

[49] Vote Solar supported this in post-workshop comments, referring to Dr. Eric Woychik's presentation, "LNBA to Integrate and Optimize DERs for Maximum Value," Presented at the Locational Benefits Analysis Workshop, (R.14-08-013), February 1 2016.

days after establishment	
Final Report on Long-Term LNBA Refinement	Q2 2017

(END OF ATTACHMENT A)

Appendix B – Utility Demonstration A & B Project Proposals[50]

Demonstration Project A

PG&E Proposal
This project aims to demonstrate the Utilities' Commission-approved Integration Capacity Analysis methodology for all line sections or nodes within a DPA. This demonstration will utilize fully dynamic modeling techniques for all line sections or nodes within the selected DPA. This demonstration shall consider two scenarios for the Integration Capacity Analysis:

1. The DER capacity does not cause power to flow beyond the substation busbar.
2. The DERs technical maximum capacity is considered irrespective of power flow toward the transmission system.

This project shall be scoped to commence no later than six months after Commission approval of PG&E's DRP.

Proposed Area of Demonstration
PG&E has identified the Central Fresno DPA for demonstrating the integrated capacity analysis methodology.

The Central Fresno DPA is located in Fresno County and services the central portion of the city of Fresno. The DPA is bounded by Herndon Avenue to the north, CA-99 to the west, CA-180 to the south, and Clovis Avenue to the east. Approximately 92,500 customers with a 2014 peak demand of 428 MW are served by four substations: Ashlan Avenue, Barton, Bullard, and Manchester. These substations are comprised of 11 substation transformer banks in total individually ranging in size from 30 megavolt amperes (MVA) to 60 MVA. The

[50] Appendix B contains excerpts of the Demonstration and Deployment Projects as filed in the utilities July 1, 2015 DRP Applications and is included here for reference purposes only.

total substation loading capacity of this DPA is 491 MW. By 2020 the DPA has a forecasted load of 490 MW (62 MW increase in five years). Also by 2020 the DPA has a retail DER expected scenario of 76.9 MW. The county of Fresno has an expected wholesale DER scenario of 58.2 MW[75] by 2020. The wholesale forecast is 58 percent PV which is likely to show up in the rural areas outside of Fresno City.

Pilot Specifications

PG&E plans to utilize the same study specifications, datasets and tools for determining Integration Capacity as discussed in Chapter 2. The datasets include hourly load profiles and power flow circuit models. Areas of improvement have been identified in both the datasets and tools to be able to more effectively and accurately determine results. PG&E is partnering with external vendors to create a year-long process of improving and enhancing the planning tools PG&E uses in distribution planning. This process involves nine major tasks that are listed as follows:

1. Load Shape Enhancement – Will develop more accurate and detailed load shapes for feeders to analyze.
2. SCADA Data Analysis – Incorporates SCADA data to validate and improve load shapes used for analysis.
3. DER Forecast Integration – Integrates methodology and results of DER scenario into planning forecast to use in locational benefit scenario analysis.
4. DER Scenario Enhancement – Develop scenario analysis to evaluate DER scenario impact to system.

5. DER Penetration Assessment – Incorporate integration capacity and penetration assessment within PG&E's load forecasting tool.
6. DRP Methodology Integration – Dynamically coordinate with development of DRP for proactive integration of methodologies.
7. Power Flow Batch Automation – Develop automation scripting to be able to analyze models in batch mode.
8. Locational Benefits – Implement locational benefit analysis into load forecasting tool.
9. Final DRP Methodology Integration (upon plan approval) – Finalize integration of DRP methodologies based on plan approval and any changes required.
10. Perform Central Fresno Analysis (upon plan approval) – Perform final integration capacity analysis on the whole DPA using completed tool.

Programs, Initiative, and Funding Utilized

As part of this pilot, PG&E plans to utilize enhancements as part of EPIC-2 Project 23 (EPIC 23), Integrate Distributed Energy Resources into Utility Planning Tools, to further increase the accuracy and granularity of the Integration Capacity Analysis. Specifically, EPIC Project 23 will enhance and integrate existing Load Analysis and Power Flow tools to help evaluate various DER solutions, for integration into utility investment planning. This would be a significant and novel expansion beyond what has been deployed by known utilities. This project facilitates the integration of a broader range of customer-side technologies and DER approaches into grid planning and operations in a least cost framework by piloting integration and usage of SmartMeter™ data, node based modeling, customer segmentation analysis, and customer specific DER forecasting.

Proposed Schedule

Development of a detailed schedule is contingent upon CPUC approval. Assuming there are no additional modifications to the specifications of this demonstration as well as there are no modifications to the Integration Capacity Analysis methodology required by the CPUC, PG&E plans to complete this

SCE Proposal – Demonstration Project A

Background – Utility Proposal

This study will be completed utilizing dynamic modeling techniques via power system modeling software (e.g., CYME, PSLF), and will not include a field demonstration. The DPA SCE intends to study will be served by an "A" level substation, which consists of multiple distribution substations with multiple circuits (or feeders) in the Orange County area of the SCE service territory (within the PRP project area). The power system modeling software will allow SCE to perform an Integration Capacity Analysis (ICA) using dynamic modeling methods for every feeder (and its respective line segments) within the DPA. Software will also be used to assess the impact of DERs producing to the grid under the two scenarios described above. The demonstration will evaluate the impact of increased levels of DERs on the electrical grid.

Specifications

1. Assess the aggregate effect to the electrical grid when DERs are interconnected across several distribution circuits served out of multiple distribution substations and when there is no reverse power flow through the distribution substation transformers (Scenario 1).

- Generation will be increased up to the hosting capacity for each distribution circuit, but just prior to the aggregate generation reversing power flow through the distribution substation transformers. This analysis will provide an understanding of the impacts to distribution circuits and distribution substations due to increased levels of DERs.

2. Assess the aggregate effect to the electrical grid when DERs are interconnected across several circuits out of multiple distribution substations and when there is reverse flow power into the sub transmission system and towards the transmission system (Scenario 2).
    - Generation will be increased up to the hosting capacity for each distribution circuit, so that the aggregate generation reverses power flow through the distribution substation transformers for multiple distribution substations. This analysis will provide an understanding of the impacts to the electrical grid due to reverse power flow from distribution circuits.

Deliverable
SCE intends to have a report finalized approximately 12 months after Commission approval of the DRP. At completion of the project, a final report will communicate the findings and recommendations to inform future iterations of the ICA and to provide other recommendations that could support operation of the system during the conditions studied.

SDG&E Proposal
The Guidance directs SDG&E to craft a demonstration project that applies the utility's proposed integration capacity analysis methodology to all line sections within it planning territory. As outlined below, SDG&E will undertake a

dynamic ICA of each line section – defined as a segment of a circuit, reflecting impedance along the main feeder – in its service territory. This demonstration project will analyze each circuit based on thermal, voltage, and protection limits. SDG&E will perform the ICA utilizing Synergi power flow software and its suite of automation tools, including the new dynamic modeling module. Below are the necessary steps identified and their descriptions.

1. Determine the three segments on each feeder by identifying the start and end of each impedance zone on the main feeder.
    a. SDG&E will run a scan in Synergi to determine the maximum impedance of each feeder. Once the maximum impedance is determined, the feeder will be divided into three segments.
2. Synthesize the circuit demand profile from AMI, SCADA, or other data, and input into Synergi.
3. Conduct power flow analysis to determine thermal and voltage limits on each line section utilizing Synergi.
    a. SDG&E will place a 1MW generator at different points along each segment, and perform a power flow analysis to determine if the generator violates thermal or voltage limits anywhere along the feeder. If no violations are identified, the capacity of the generator will be increased and the power flow analysis rerun. This process will continue until a violation is identified.
4. Conduct short circuit analysis to determine protection limits on each line section.
    a. Similar to the power flow analysis, SDG&E will model a 1 MW generator at different points along each segment and perform a short circuit analysis to determine if the generator violates

protection limits anywhere along the feeder. If no violations are identified, the generator's capacity will be increased and the short circuit analysis rerun. This process will continue until a violation is identified.

5. Once a violation is identified, the integration capacity will be the largest generation capacity that passed the analysis without any violations. For the initial analysis, DER generation shall remain below the minimum load on each circuit, ensuring no power flow back to the substation. For those circuits that have an IC that does not reach a limit below the backflow limit, further analysis will be performed to determine the maximum integration capacity regardless of the backflow into the substation.

Implementation Schedule

As required by the Guidance, SDG&E will commence this project no later than six months after the Commission approves SDG&E's DRP. Once commenced, SDG&E will require approximately eight months to complete the ICA demonstration. Below is the detailed implementation schedule for the project.

Demonstration Project B Utility Proposals

PG&E Project B Description

Objective

This project aims to demonstrate PG&E's Commission-approved optimal location benefit analysis methodology for one DPA, in which that DPA has one near term (0-3 years) and one longer term (3 years or greater) distribution infrastructure project that can be deferred due to integration of DERs. This demonstration project shall be scoped to commence no later than 1 year after Commission approval of PG&E's DRP.

Proposed Area of Demonstration

To further demonstrate alignment of the proposed distribution planning frameworks, PG&E is proposing to demonstrate its Optimal Location (Net) Benefit Methodology on the Central Fresno DPA, which is also being utilized for the demonstration on Dynamic Integration Capacity Analysis 3.a). A description of the Central Fresno DPA is included in Section 3.a.ii. Specifically, for the Central Fresno DPA, PG&E is considering one near term (0-3 years) project involving deferral of increasing distribution transformer capacity. In the long term (greater than 3 years), PG&E is also evaluating if this distribution transformer capacity can be deferred beyond three years.

Pilot Specifications

The specifications for this pilot include the following steps:

1. Perform distribution planning capacity and reliability assessment to determine location and timing of impacted facilities in Central Fresno DPA.

2. Determine project scope, cost estimate and implementation schedule for upgrading impacted facilities

3. Perform Integration Capacity Analysis for Central Fresno DPA. Evaluate DERs as an alternative to mitigate identified capacity/reliability issue.

4. Determine feasible short term projects that can deliver requirements for projects within a 3-year time frame. Determine feasible long-term projects that can deliver requirements for projects that are greater than three years out.

5. Determine service requirements for DERs to address identified capacity/reliability issue.

6. Determine location(s) where DER(s) are required in Central Fresno DPA, along with suggested DER portfolio mix (considering DER loading profile).

7. Compute locational value for specific points within Central Fresno DPA based on avoided utility costs and amount of DER required per location.

8. Compute ratio of avoided cost and required DER capacity (results provided in $/kW, cost per DER capacity)

Programs, Initiative, and Funding Utilized

This demonstration will both leverage and inform the work envisioned under EPIC Project 23 to enhance planning tools for dynamic DER analysis. EPIC Project 23 is focused on integrating enhanced techniques of DER analysis into PG&E's Load Forecasting and Power Flow Analysis planning tools, which are used to perform technical studies regarding distribution system reliability.

Proposed Schedule

Development of a detailed schedule is contingent upon CPUC approval. Assuming there are no additional modifications to the specifications of this demonstration as well as there are no modifications to the optimal location net benefits methodology required by the CPUC, PG&E plans to complete this analysis within 12 months after Commission approval of this DRP.

SCE Project B Description

Background

Pursuant to the Final Guidance, SCE is required to develop a specification for a project to demonstrate the Commission approved Optimal Location Benefit Analysis Methodology (LNBM Demonstration). Pursuant to Final Guidance

Requirement No. 1.b, SCE proposed a locational net benefits methodology (LNBM) as part of Chapter 2 of the DRP.

This project will be a study to demonstrate the LNBM and will not include a field demonstration. The LNBM is based on E3's Distributed Energy Resource Avoided Cost (DERAC) tool and includes components such as generation energy, T&D losses, generation capacity, T&D capacity investment deferral, and other components. In this demonstration, SCE will calculate the T&D capacity investment deferral on two distribution infrastructure projects, one near-term (0-3 year lead time) and one longer-term (3 or more years lead time) within the same distribution planning area (DPA).

Specifications

1. Demonstrate use of the LNBM in the SCE distribution planning process for identification of projects for evaluation.
    - Identify two potential projects for deferral, one near-term and one longer-term.
    - Calculate the T&D capacity investment deferral on the two projects.
2. Construct DER portfolios that can help meet the grid needs.
    - Assess the capability of different sample portfolios of DERs.
3. Apply the LNBM.
    - Apply the LNBM to the sample DER portfolios.
4. Assess any potential timing considerations.
    - Given that one project is near-term and the other is longer-term, SCE will evaluate the potential timing considerations associated with pursuing and ensuring DERs would be operational within the needed timeframe.

Deliverable
SCE intends to have a report finalized approximately 12 months after Commission approval of the DRP. At completion of the project, a final report will communicate the results of the comparison, identify lessons learned, and recommend ways to refine the LNBM.

SDG&E Project B Description

Project Description

The Guidance requires SDG&E to scope a demonstration project that performs the utility's proposed optimum locational net benefits analysis within its distribution planning area. In compliance with this directive, SDG&E's proposed demonstration will focus on performing the proposed LNB analysis in selected area(s) with previously identified distribution capital projects. For this demonstration project, SDG&E intends to analyze the Oceanside area, where SDG&E has identified the need to build a new distribution substation to serve growing demand. SDG&E believes that given the proper specifications, a DER project could potentially defer the substation project. SDG&E will determine what portfolio of DERs is appropriate to meet the capacity need for the Oceanside area and utilize the LNBM to determine the value of the DER portfolio versus the traditional substation project.

If additional projects are identified, they may be circuits, substations, or voltage control projects. For circuit and voltage projects, a DER solution may result in a deferral or replacement of the capital project. For a new distribution substation, a DER solution will typically be a deferral of the project, as load growth in the area will eventually require a substation. The net benefits for the DER project will be calculated utilizing the proposed methodology outlined in section 1b, as approved and/or modified by the Commission. SDG&E's proposed project will focus on distribution infrastructure projects with at least a three-year lead time. Since SDG&E must address distribution deficiencies in a timely manner, the utility will continue to propose traditional infrastructure projects for near-term deficiencies.

The demonstration project will accomplish several objectives:

1. Identifying traditional projects that can be deferred by DER
2. Identifying the operating characteristics of a DER project that can defer/eliminate a traditional project
3. Determining length of deferral achieved by DER
4. Calculating net benefits resulting from installation of the DER project

Implementation Schedule

As required by the Guidance, this demonstration will commence within one year of the Commission's approval of SDG&E's DRP. SDG&E will require approximately nine months after commencement to complete the LNBM demonstration.

(END OF ATTACHMENT B)