Appendix A

Glossary of Acronyms

R. 14-08-013

Glossary of Acronyms

A.: Application

AB: Assembly Bill

ACR: Assigned Commissioner's Ruling

AMI: Advanced Metering Infrastructure

April 19, 2017 Ruling: *Assigned Commissioner's Ruling Requesting Comments on the Integration Capacity Analysis and Locational Net Benefits Analysis Final Short-Term Working Group Reports*

CalSEIA: California Solar Energy Industries Association

CAISO: California Independent System Operator

CapEX: Capital Expenditure

CSF: Competitive Solicitation Framework

CVR: Conservation Voltage Reduction

D.: Decision

DAG: Distribution Deferral Advisory Group

DER: Distributed Energy Resource

DERAC: Distributed Energy Resources Avoided Cost Calculator

Deferral Framework: Distribution Investment Deferral Framework

DPA: Distribution Planning Area

DRP: Distribution Resources Plan

GIS: Geographic Information Systems

GRC: General Rate Case

ICA: Integration Capacity Analysis

IDER: Integrated Distributed Energy Resources

IOUs: Investor-Owned Utilities

IRP: Integrated Resource Planning

June 7, 2017 Ruling: *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

LNBA: Locational Net Benefit Analysis

May 2, 2016 Ruling: *Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*

NEM: Net Energy Metering

ORA: Office of Ratepayer Advocates

PG&E: Pacific Gas and Electric Company

PV: Solar Photovoltaic

R.: Rulemaking

RAM: Renewable Auction Mechanism

RECC: Real Economic Carrying Charge

SCADA: Supervisory Control and Data Acquisition

SCE: Southern California Edison Company

SDG&E: San Diego Gas and Electric Company

T&D: Transmission and Distribution

TRR: Transmission Revenue Requirement

WG: Working Group

(End of Appendix A)

Appendix B

Demonstration Project A Compliance Matrix

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Load forecasting and DER growth scenarios	IOUs shall 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; 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.	Section 1.1, p5	Final Report Chapter 4.3.1 [load forecasts], 5.1.2 [the 2yr DER growth scenario and scenarios I and III], 5.2 [ICA results in each DPA], 5.3 [methodology comparison results] and downloadable data files	Final Report 4.c [Load and DER forecasts], 5.b pg. 83 [ICA results in each DPA, load forecasting and DER growth scenarios (I and III)]	Final Report 3 [2 DPAs] 4.c [Model and Extract Power System Data], 4.c.ii [load forecast and DER growth scenarios (I and III)], 5 [results], and downloadable data files
Baseline Method Steps					
Establish Distribution system level of granularity	Analysis shall be performed down to specific nodes within each line section of individual 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.	Section 1.3, p 6	Final Report Chapter 4.2 [ICA values down to all three-phase primary nodes and line sections for all distribution feeders within the two selected DPAs]	Final Report 4.b pg. 30 [granularity down to each nodes on the primary side of service transformers]	Final Report 4.b [granularity down to the nodal level]

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
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.	Section 1.3, p 7	Final Report Chapter 4.3 [CYMDIST for power flow analysis], 4.3.1 [576 load data points]	Final Report 4.c [CYMDIST for power flow analysis], Final Report LNBA Ch. 4.1 [load forecasting with LoadSEER], 7.b.iii-iv pgs. 123-124 [several load profiles for each DPA]	Final Report 4.c [LoadSEER, Synergi used], 4.c.iii [9 load profiles] 5.c.i [576 hour analysis]

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
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 factors listed in PG&E's Table 2-4 in their DRP Application under "Initial Analysis" and summarized below: (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. (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. Other limitations supporting the safe and reliable operation of the distribution system apply.	Section 1.3, p. 7-9	Final Report Chapter 4.4 a. Thermal criteria (p.24-25) 4.4.2 b. Power quality/voltage criteria: (p.26-27) 4.4.3-4.4.5 c. Protection criteria: (p.27-28) 4.4.6 d. Safety/reliability criteria: (p.29) 4.4.7	Final Report 4.d, a. Thermal criteria: (pg. 54-56) 4.d.ii b. Power quality/voltage criteria: (pg. 56-59) 4.d.iiii c. Protection criteria: (p.60-61) 4.d.iv d. Safety/reliability criteria : (p.61-63) 4.d.v	Final Report 4.d a. Thermal criteria: (p.34-35) 4.d.ii b. Power quality/voltage criteria: (p.35-37) 4.d.iii c. Protection criteria: (p.37-38) 4.d.iv d. Safety/reliability criteria (p.38-39) 4.d.v

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
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 SQL11 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.	Section 1.3, p 9	Final Report Chapter 4.1.3; 7 (p.16) layered abstraction approach described ICA data is publicly available on the RAM map	Final Report 4.d.i, Ch.4 (pg. 49) [layered abstraction approach] ICA data is publicly available on the RAM map	Final Report 4.d [4.d.i.3] (p.34) layered abstraction approach. ICA data is publicly available on the RAM map
Specific Modifications to Include in Baseline Method					
Quantify the Capability of the Distribution System to Host DER	(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	Section 1.4, P 9-10 (and Section 1.1, p 1-2)	Final Report Chapter 4.3.2 (p.19-20) mentions including capacitor banks in model.	Final Report 4.c (p.36)	Final Report 4.c.i (p. 33)

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Quantify the Capability of the Distribution System to Host DER	(b). Power flow analysis shall be calculated across multiple feeders {circuits], whenever feasible for more accurate ICA values. All feeders that are electrically connected within a substation shall be included in this analysis.	Section 1.4, P 9-10	Final Report Chapter 4.3.2 (p.19-20) Process shown in diagram	Final Report 4.c (p.38-39) Circuits modeled in CYME include expanded scope of models to the substation components that electrically connect feeders on the same substation transformer.	Final Report 4 (p.33) process explained for iterative method
	(c). The ICA shall be modified to reflect DERs that reduce or modify forecast loads.	Section 1.4, P 9-10	Final Report 4.3.1	Final Report 4.c (pg. 45) ICA modified to reflect DERs that modify forecast load	Final Report 4.c.ii.2 (p.27)
	(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.	Section 1.4, P 9-10	Final Report Chapter 4.3.2 (p.19-21) none are apparent here; [4.4.4] (p.26) see SDG&E response	Final Report 4 (p.57) see SDG&E response	Final Report 4 (p.36) The power factor of DERs is assumed at 1 in the study. Not sure of any others.
Common Methodology Across All Utilities	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.	Section 1.4, p 10 (and Section 1.1, p 2)	Final Report Chapter 4.1 (p.15) see SDG&E response	Final Report 4 (p.27-28) see SDG&E response	Final Report 4.d [4] (p.18) modified baseline methodology overview and process diagram

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Different Types of DERs	(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. 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)	Section 1.4, p 11 (and Section 1.1, p 2)	Final Report Chapter 8.2 (p.68-70) ICA translator tool described for analysis	Final Report 8.b (p.135) DER operational profile output results graphed/ charted.	Final Report 8.b (p.63) DER specific results for key DER operational profiles [4.c.iii] (p.29-30) all DER profiles graphed together
	(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.	Section 1.4, p 11	Final Report Chapter 8.2 (p.68-70) quantified for analysis and example numbers in ICA translator tool picture.	Final Report 8.b (p.135) DER Specific Results from Hourly ICA Profile. Not for portfolios	Final Report 8.b (p.63) DER Specific Results from Hourly ICA Profile [4.c.iii] (p.29-30) all DER profiles by ICA
	(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.	Section 1.4, p.11-12	Final Report Chapter 8.2 (p.68) Method based on ICA Translator Tool described.	Final Report 8.b	Final Report 8.b (p.63) SCE ICA Translator Tool
	(d) The ICA Working Group shall identify additional DER portfolio combinations	Section 1.4, p 12	Final Report Chapter 8.2	Final Report 8.b	Final Report 8.b
Granularity of ICA in Distribution System	Locational granularity of ICA is defined as line section or node level on the primary distribution system, as specified in the PG&E methodology	Section 1.4, p 12 (and Section 1.1, p 2)	Final Report Chapter 4.2 (p.17) down to the nodal level	Final Report 4.b (p.30) nodal level.	Final Report 4.b (p.21) Granularity to the nodal level.

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Thermal Ratings, Protection Limits, Power Quality (including Voltage), and Safety Standards	(a) Include all the different types of defined power system criteria and sub criteria in the analysis. 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.	Section 1.4, p 12 (and Section 1.1, p 2)	Final Report Chapter 4.4, Appendix b) (p.24-32) see PG&E response	Final Report 4.d.ii, 4.d.iii, 4.d.iv, 4.d.v (p.54-66) thermal, power quality/voltage, protection, and safety and reliability criteria described	Final Report 4.d (p.34-39) see PG&E response
	(b) Protection Limits used in ICA – The IOUs shall agree upon on a common approach to representing protection limits in the ICA.	Section 1.4, p 12	Final Report Chapter 4.4.6 (p.28) common protection limit approach	Final Report 4.d.iv (p.61) common protection limit approach	Final Report 4.d.iv (p.37) common protection limit approach
Thermal Ratings, Protection Limits, Power Quality (including Voltage), and Safety Standards	(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.	Section 1.4, p 13	SCE's Intermediate Status Report for Demonstration Project A (p.13-14) ICA limit criteria and threshold values described	Final Report 4.d. [Interim Status Report] (p.14-17) see SCE response	Final Report 4.d [Interim Status Report] (p.8-10) see SCE response

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Thermal Ratings, Protection Limits, Power Quality (including Voltage), and Safety Standards	(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.	Section 1.4, p 13	Final Report Chapter 4.4 (p.26, 84) See SDG&E response	Final Report 4.d (p.56, 152) See SDG&E response	Final Report 4, 9 (p.35-36, 71) Thermal criteria are based on equipment ratings established by manufacturers and design criteria established in CPUC General Orders 95 and 128. Steady state voltage criteria are determined by the IOUs' Rule 2, which are drawn from American National Standard (ANSI) C84.1 - 2011 Range A. Transient voltage criteria align with IEEE recommended practice defined in IEEE Standard 1453-2015. Both protection and operational criteria are based on the EPRI hosting capacity methodology and align with the IOU's system design and operating standards as well as interconnection standards.

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Thermal Ratings, Protection Limits, Power Quality (including Voltage), and Safety Standards	(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).	Section 1.4, p 13	Final Report Chapter 7; Online map; downloadable data files (p.58-60) SCE provides all the required information in its map application.	Final Report 7.b (p.121) PG&E provides all the required information in the feeder layer pop-up window.	Final Report 7.b (p.58) all information provided in online map application as exemplified by figure 42.
	(f). Identify feeders where sharing the information in paragraph "e" violates any applicable data sharing limitations.	Section 1.4, p 13	N/A	Final Report 7.b (p.121) Using percentage of customer type breakdown, instead of actual customer count, may prevent violating any applicable data sharing limitations to certain extent, but data sharing limitations will still be examined to make sure there are no violations.	N/A
Thermal Ratings, Protection Limits, Power Quality (including Voltage), and Safety Standards	(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 profiles, reactive power requirements, or specific information related to potential system protection concerns.	Section 1.4, p 13-14	Final Report Chapter 5; downloadable data files	Final Report 7.b.ii (p.122-124) example outputs of downloadable data included.	Final Report 5, 7 (p.40-41) data meets criteria

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
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.	Section 1.4, p 14 (and Section 1.1, p 2)	Final Report Chapter 7; downloadable data files (p.55) Information made available via ICA maps. Keys and explanations in SCE links.	Final Report 7 (p.118-124) Information made available via ICA maps. Feeder layer has a pop-up window with a download option.	Final Report 7 (p.57-58) For all popups, a link to the Demo A data set is included for users to download the entire data set for review and manipulation. This data will be in the form of a .csv file which can be used with data analytic programs.
	(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.	Section 1.4, p 14	Final Report Chapter 7 (p.55) ICA results in Distributed Energy Resource Interconnection Map;	Final Report 7 (p.118) ICA results with RAM map information	Final Report 7 (p.57-59)
Time Series or Dynamic Models	ICA shall utilize a dynamic or time series analysis method as specified in the Guidance. This analysis shall be consistent among the three IOUs. 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. 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.	Section 1.4, p 14-15 (and Section 1.1, p 2)	Final Report 4.1 [9.3] (p.84) Adopted an hourly time series analysis as part of meeting ORA's criteria for "reasonable resolution (a) spatial, (b) temporal"	Final Report 4 [9.c] (p.153) See SCE response	Final Report 4.c.iii [9.b] (p.84) See SCE response

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Avoid Heuristic Approaches, where possible	There are no new modifications based on this Guidance requirement	Section 1.4, p 15 (and Section 1.1, p 2)	Final Report Chapter 4.4 (p.31) see SDG&E response to the right	N/A	Final Report 4 (p.39) The IOUs recognize that this [the operational flexibility criteria] is more of a heuristic approach. While heuristic approaches were not encouraged, the IOUs have established that non-heuristic approaches to analyzing this issue are quite process intensive and will significantly hinder the ability to achieve efficient results. In essence, this will not necessarily limit the amount of generation that can be placed on each substation, but can be used to disperse the generation across all line sections connected to the substation. This is an important aspect of reliability that needs to be addressed for high penetration scenarios of DER.

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
General Requirements					
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.	Section 2, p 15 (and Section 1.1, p 4)	Final Report Chapter 4; 5 [5.1.1] (p.33) scenarios described	Final Report 5.b (p.77-79) compares the 2 scenarios visually with results for both DPAs	Final Report 5 (p.40) scenarios described and results in table
Project Schedule	Demonstration A project schedules proposed in IOU Applications are modified and shall commence immediately with the issuance of this Ruling.	Section 2, p 16	SCE's Implementation Plan for Demonstration Projects A (p.19-20)	N/A	N/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.	Section 2, p 16 (and Section 1.1, p 3)	Final Report Chapter 3 (p.9-11) Two DPAs: Johanna in Orange County (urban) and Rector in the Central Valley (rural) and justification.	Final Report 3 (p.21-23) two DPAs: Chico (urban/ suburban) and Chowchilla (rural) and justification.	Final Report 3 (p.16) two DPAs: Northeast SD County (urban/ suburban) and Ramona (rural) and justification for picking them.

Appendix B – Demonstration Project A Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Project Detailed Implementation Plan	IOUs shall submit detailed implementation plans for project execution, including metrics, schedule and reporting interval. 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. 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 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.	Section 2, p16-18	SCE's Implementation Plan for Demonstration Projects A a. learning objectives (p.7-8) b. revised methodology (p. 8-17), process flow chart (p.9) c. load forecasting description (p.17-19) d. Schedule/ Gantt Chart (p.19-20) e. Additional resources (p.21) f. Plan for monitoring and reporting results (p.21) g. Availability of project files (p.21) h. additional information necessary to determine the probability of accurate results – unclear i. ORA success metrics (p.23-24)	N/A [See PG&E's Implementation Plan for Demo A] a. learning objectives (p.A6-A7) b. revised methodology (p. A8-A22), process flow chart (p.A17) c. load forecasting description (p.A26-A27) d. Schedule/ Gantt Chart (p.A28) e. Additional resources (p.A29) f. Plan for monitoring and reporting results (p.A29) g. Availability of project files (p.A29) h. additional information necessary to determine the probability of accurate results – unclear i. ORA success metrics (p.A34-A35)	The plan was submitted June [16], 2016. a. learning objectives (p.3-4) b. revised methodology (p. 6-14), process flow chart (p.9) c. load forecasting description (p.15-16) d. Schedule/ Gantt Chart (p.17) e. Additional resources (p.18) f. Plan for monitoring and reporting results (p.18) g. Availability of project files (p.18) h. additional information necessary to determine the probability of accurate results (p.18-21) i. ORA success metrics (p.21-24)

(End of Appendix B)

Appendix C

Demonstration Project B Compliance Matrix

Appendix C – Demonstration Project B Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
DPA Selection/ Projects for Deferral	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. 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.	4.1; pg. A24	Final Report Chapter 4.1 Criteria met (p.20): SCE selected five distribution substations within the Rector Sub-transmission system as its DPA with planned projects related to capacity expansion, power quality, and voltage support, with lead times from 2017 through 2025	Final Report 2, 4, [5] [2.2] p. 9: Chowchilla and Chico DPAs selected (p. 32-35) Nine deferrable projects currently planned in Chowchilla (DPA), all of which are either categorized as distribution capacity, voltage support or a combination of the two. Projects' years of completion range from 2018 (near-term) to 2022 (long-term).	Final Report 3 [4] [3] p. 20: Evaluating Northeast planning district (p.25-35) Voltage support and capacity projects identified with forecast lead-times as early as 2016.

Appendix C – Demonstration Project B Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
LNBA Methodology Requirements	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.	4.3; pg. A26-A28	Final Report Chapters 8, 9 (p.60) [DERAC values] the system-level avoided cost module calculates the benefits of system wide components. These components include avoided energy, avoided generation capacity, avoided GHG, avoided RPS, avoided ancillary services, renewable integration cost adder, and societal and public safety, [(p.61) 9.2.3 system level values not incorporate. In DERAC] Appendix 2, [(p.6) 2.1 Given that the secondary analysis would require significant time to develop additional methodologies and the time constraints for Demo B, as acknowledged in the ACR, SCE decided to pursue the primary analysis.	Final Report 8, 9, Appendix 2 (See LNBA Tool tab) [9.2.3] (p.46) DERAC values described. Flexible RA and integration costs are also included.	Final Report 7, Appendix 2, (LNBA Tool) [7.4.5] (p.52) DERAC values described. Flexible RA and integration costs are also included. (Also in Appendix 2 A2-8 – A2-10).
Table 2 [ACR]	Primary Analysis	4.3; pg. A27-A28	Final Report Chapter 2.1 (p.7)	Final Report 2.1.2 (p.8)	Final Report 7, Appendix 2, (LNBA Tool) (p.54)
LNBA Specific Requirements					

Appendix C – Demonstration Project B Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Project Identification	The IOUs shall identify the full range of electric services that result in avoided costs for all 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.	4.4.1 (1)(A); pg. A29	Final Report - Chapters 3, 5 [5.1 (p.32-45) services listed by project], 6, 7 9p.50-52) reliability projects; Downloadable Dataset - 'Deferrable Project Data' tab, 'Non Deferrable Project Data' tab; [3.1 (p.12-15) electric services that DERs can provide in Demo B: transmission and distribution capacity deferral, voltage support, reliability – back-tie, resiliency via microgrid.	Final Report Ch. 3, 5, 6, 7; Appendix 4 Downloadable Dataset 3 (p.11-20) identifies range of electrical services that can and cannot be provided by DERs 5.2 (p.32) distribution capacity and voltage support. 7 (p. 37) Reliability projects	Final Report Chapter 2, 4, 5, 6 Downloadable Dataset [2.1] (p.8- 11) services include transmission and distribution capacity, voltage support, reliability – back-tie, resiliency via microgrid and avoided energy losses.
List of Locations for Projects	Develop a list of locations where upgrade projects, circuit reliability, or maintenance projects may occur over each of the planning horizons to the extent possible	4.4.1 (1)(B)i; pg. A29	Final Report - Chapters 5 (p. 28-45, locations described in the San Joaquin region), 6, 7 (no locations listed); Downloadable Dataset - 'Deferrable Project Data' tab (locations described in the San Joaquin region)	Final Report Ch. 5, 6, 7; Appendix 4; Downloadable Dataset (p.31 - 35) locations of identified deferral projects listed 7 (p. 37) Reliability project locations Appendix 4: O&M project locations	Final Report Chapters 4, 5, 6, Downloadable Dataset (p. 26-35) locations are listed along with project descriptions
Cost of Projects	Use existing approaches for estimating costs of required projects identified	4.4.1 (1)(B) ii; pg. A29	Final Report Chapter 8	Final Report Chapter 8	Final Report Chapter 7

Appendix C – Demonstration Project B Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Time Horizon of System Upgrade Needs	System upgrade needs identified in the processes 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.	4.4.1 (1)(B)iii; pg. A29	Final Report - Chapters 5 (entire chapter), 6, 7; Downloadable Dataset - 'Deferrable Project Data' tab lists the in-service dates	Final Report Ch. 5, 6, 7; Downloadable Dataset and Heat Map	Final Report Chapters 4, 5, 6
List of Electric Services from Projects	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.	4.4.1 (1)(B)iv; pg. A30	Final Report Ch. 5, 6, 7; Downloadable Dataset -'Deferrable Project Data' tab; LNBA Heat Map	Final Report Ch. 5, 6, 7; Downloadable Dataset and Heat Map	Final Report Chapters 4, 5, and 6; Downloadable Dataset and Heat Map
DER capabilities to provide Electric Services	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.	4.4.1 (1)(B)v; pg. A30	Final Report Chapter 3.1 (p.12-15)	Final Report Chapter 3.1 (p.12-14)	Final Report Chapters 2.1 (p.8-11)

Appendix C – Demonstration Project B Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Specifications of System Upgrade Needs	A description of the various needs underlying the distribution grid upgrades; Electrical parameters for each grid upgrade including total capacity increase, real and reactive power management and power quality requirements; An equipment list of components required to accomplish the capacity increase, maintenance action or reliability improvement; Project specifications for reliability, maintenance or capacity upgrade projects identified by the utilities shall include specifications of the following services as applicable: Voltage Control or Regulation, Reactive Supply, Frequency Regulation, Other Power Quality Services, Avoided Energy Losses, Equipment Life Extension, Improved SAIFI, SAIDI and MAIFI results.	4.4.1 (1)(B) vi(a-d); pg. A30	Final Report - Chapters 5, 6, 7; Downloadable Dataset - 'Deferrable Project Data' tab, 'Deferral Requirement Profile' tab Needs: described in report (p.28-45) and in data under "Key Driver of Need" column in the Deferrable Project Data tab. Equipment List: (p.28-45)	Final Report Ch. 5 and Downloadable Dataset Deferral Project Needs and Equipment List: (p.33-35)	Final Report Ch. 4, 5, 6 and Downloadable Dataset Deferral Project Needs and Equipment List: (p.26-35)
Compute Avoided Cost	Compute a total avoided cost for each location within the DPA selected for analysis using the Real Economic Carrying Charge [(RECC)] method to calculate the deferral value of these projects. Assign these costs to the four avoided cost categories in the DERAC calculator for this location. Use forecast horizons consistent with the time horizon above.	4.4.1 (1)(B)vii(a- c); pg. A31	Final Report Chapters 8 and 9; LNBA Tool - 'Project Inputs & Avoided Costs' tab	Final Report Chapters 8 and 9; LNBA Tool - 'Project Inputs & Avoided Costs' tab	Final Report Chapter 7; LNBA Tool - 'Project Inputs & Avoided Costs' tab

Appendix C – Demonstration Project B Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Distribution System Services – Conservation Voltage Reduction [(CVR)] and Volt/VAR optimization [(VVO)]	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.	4.4.1 (1)(C); pg. A31	Final Report Chapter 3.2.1 (p.15-16) CVR and VVO are not currently estimated or otherwise included in Demo B LNBA values.	Final Report Chapter3.2.2 (p.15) In Demo B, the IOUs have not done the engineering analysis and field research to estimate these quantities; however, a benchmarking exercise summarized in PG&E's 2017 GRC found that prior studies indicate a range of 0.76 to 4 for average voltage reduction percent and a range of 0.06 to 2.7 for the CVR factor.	Final Report 2.2.1 (p.12-13) In Demo B, the IOUs have not done the engineering analysis and field research to estimate these quantities; however, a benchmarking exercise summarized in PG&E's 2017 GRC found that prior studies indicate a range of 0.76 to 4 for average voltage reduction percent and a range of 0.06 to 2.7 for the CVR factor.
Transmission CapEx	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, materialize as assumed in those locations. The IOUs shall provide work papers with a clear description of the methods and data used. 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.	4.4.1 (2) + (A); pg. A31-A32	Final Report - Chapter 8.3 (p.58-59) the 2015-2016 Transmission Plan does not provide sufficient information to do this analysis. The default transmission value is set to zero, consistent with the default value found in the Public Tool developed in the NEM Successor Tariff Proceeding (R.14-07-002); LNBA Tool - 'DER Dashboard' K6 – defined in the tool as "Transmission avoided cost ($/kW of DER)"	Final Report 8.3 (See also LNBA Tool tab) (p.44) same response as SCE	Final Report 7.3 (p.49-52) same response as the other IOUs

Appendix C – Demonstration Project B Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Line Losses	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.	4.4.1 (3); pg. A32	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.
Flexible Generation	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. The IOUs shall provide work papers with a clear description of the methods and data used.	4.4.1 (4); pg. A32	Final Report 9.4 (p. 63) In the LNBA tool, the value of flexible capacity was assumed to be $20 / kW-yr in 2016. For future years, the $20 / kW-yr value was escalated by 5% each year. To calculate the value of the avoided flexible capacity for a specific DER solution, the DER solution hourly profile is assessed for its impact on the annual maximum three-hour ramp, upon which the flexible RA requirements are based	Final Report 9.4; Appendix 2 (p.47-48) In the LNBA tool, the value of flexible capacity was assumed to be $20 / kW-yr in 2016. For future years, the $20 / kW-yr value was escalated by 5% each year. To calculate the value of the avoided flexible capacity for a specific DER solution, the DER solution hourly profile is assessed for its impact on the annual maximum three-hour ramp, upon which the flexible RA requirements are based.	Final Report 7.6.3 (p.54) The avoided cost for flexible capacity is defined as the value of flexible capacity that does not need to be procured from the offsetting flexible capacity provided by the DER solution. In the LNBA tool, the value of flexible capacity was assumed to be $20 / kW-yr in 2016. For future years, the $20 / kW-yr value was escalated by 5% each year. To calculate the value of the avoided flexible capacity for a specific DER solution, the DER solution hourly profile is assessed for a three hour ramp.
Avoided Energy - LMPs	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.	4.4.1 (5); pg. A32	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.	N/A, Demo B LNBA Methodology focuses on the Primary Analysis in Table 2 of the ACR only.

Appendix C – Demonstration Project B Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Avoided Costs - Renewable Integration, Societal, and Public Safety	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 values or descriptions in the detailed implementation plans	4.4.1 (6); pg. A32-A33	Final Report 9.6 and 9.7 (p.63-64) Renewable Integration costs derived from D.14-11-042; For Demo B, no societal or public safety components were quantified.	Final Report Ch. 9.6 and 9.7 (p.48-49) Renewable Integration costs derived from D.14-11-042; For Demo B, no societal or public safety components were quantified.	Final Report 7.8 (p.55) Renewable Integration costs set at $3/MWh for solar, $4/MWh for wind, and $0/MWh for all other technologies. No discussion of Societal and Public Safety costs.
Methodology Description	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.	4.4.1 (7); pg. A33	Final Report Appendix 2 - Methodology (p.89-95) - Modeling techniques/software– Excel VBA (p.84) - Inputs (p.85-89)	Final Report Ch. 8, 9, Appendix 2 pdf 224 (p.38) - Methodology (Ch. 8-9) - Modeling techniques/software– Excel VBA (Ch. 9) - Inputs (p.39-45)	Final Report Appendix 2 - Methodology (p.A2-8 – A2-14) - Modeling techniques/software– Excel VBA (p.A2-1) - Inputs (p.A2-2 – A2-8)
Software and Data Access	The IOUs shall provide access to any software and data used to stakeholders, within the limits of the CPUC's confidentiality provisions.	4.4.1 (8); pg. A33	Final Report 2.3-2.4; LNBA Tool, Heat Maps publicly available	Final Report 2.2.1-2.2.2; LNBA Tool, Heat Maps and datasets publicly available	Final Report 1.3-1.4; LNBA Tool, Heat Maps publicly available
DER Load Shapes and Adjustment Factors	Both the primary and secondary analyses should use the load shapes or adjustment factors appropriate to each specific DER.	4.4.1 (8); pg. A33	Final Report Appendix 2 (p.22-23) use of load shapes in analysis	Final Report Ch. 4, (p.27-29, 52-55) Appendix 1 use of load shapes in analysis	Final Report Appendix 2, [3] (p.20-24) use of adjustment factors and load curves
Other Related LNBA Requirements					

Appendix C – Demonstration Project B Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
Heat Map	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 also be required as determined in the data access portion of the proceeding.	4.4.2 (1); pg. A33	LNBA Heat Map publically available at http://www.arcgis.com/home/webmap/viewer.html?webmap=e62dfa24128b4329bfc8b27c4526f6b7	LNBA Heat Map publically available at https://www.pge.com/b2b/energysupply/wholesaleelectricsupplier solicitation/PVRFO/DemoBMap/DemoB.html	LNBA Heat Map publically available at https://www.sdge.com/generation-interconnections/enhanced-integration-capacity-analysis-ica
DER Growth Scenarios	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. 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.	4.4.2 (2) + (a); pg. A33	Final Report 4.3 (p.23-25) Both growth scenarios detailed	Final Report 4.2 (p.22-23) describes the growth scenarios	Final Report 3.2 (p.24) As outlined in the ACR, SDG&E included the IEPR baseline DER growth scenario in the construction of its load curves as well as the Integrated Energy Policy Report (IEPR) High DER Growth forecast in its alternative DER forecast scenario.
General Requirements					
Equipment Investment Deferral	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.	5.1 (C); pg. A34	Final Report - Chapters 5, 6, 7; Downloadable Dataset - 'Deferrable Project Data' tab (p. 27-45) a. No b. No c. Yes d. No e. No f. No g. Yes	Final Report Downloadable Dataset [5] (p.29-35) a. Yes b. No c. Yes d. No e. No f. No g. Yes	Final Report Chapters 2, 4, 5, 6 (p.25-35) a. Yes b. No c. No d. No e. No f. No g. No

Appendix C – Demonstration Project B Compliance Matrix

Requirement	ACR Description	ACR	SCE	PG&E	SDG&E
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 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: A detailed 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 (vendor or contract) work required to support it; Additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested; Any additional resources required to implement Project B not described in the Applications	5.1 (d) + (i-iii); pg. A34-A35	SCE's Implementation Plan filed June 16, 2016 -Methodology (Appendix C p.31-52) - Load forecasting (Appendix B p.24) - Schedule/Gantt chart (p.17) - Additional project details and milestones (e.g. deliverables) (p.16-17)	PG&E's Implementation Plan filed June 16, 2016 - Methodology (Appendix B p.B24) - Load forecasting (Appendix A p.B17) - Schedule/ Gantt chart (pB14) - Additional project details and milestones (e.g. deliverables) (p.B13-B14)	SDG&E's Implementation Plan filed June 16, 2016 - Methodology(p.2, 8-9, Appendix C) - Load forecasting (p.14) - Schedule/Gantt chart (p.11) - Additional project details and milestones (e.g. deliverables) (p.11)
Reporting	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.	5.1 (d)(iv); pg. A35	SCE's Implementation Plan filed June 16, 2016	PG&E's Implementation Plan filed June 16, 2016 Plan for monitoring and reporting results (p.B13-B14)	SDG&E's Implementation Plan filed June 16, 2016 Plan for monitoring and reporting results (p.9-11)

(End of Appendix C)

APPENDIX D

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX

TO

INTEGRATION CAPACITY ANALYSIS

WORKING GROUP FINAL REPORT

California Distribution Resources Plan (R.14-08-013)
Integration Capacity Analysis Working Group
Final ICA WG Report

Table of Contents

1 Executive Summary

Assembly Bill 327 (Perea 2013) established Section 769 of the California Public Utilities Code, which requires the Investor Owned Utilities (IOUs) to prepare Distribution Resource Plans (DRPs) that identify optimal locations for the deployment of distributed energy resources. In August 2014, the Commission began implementation of this requirement through Rulemaking (R.) 14-08-013, the DRP proceeding. A Ruling from the Assigned Commissioner in November 2014 introduced the Integration Capacity Analysis (ICA) as a tool to specify how much capacity for integrating circuits on the distribution system may have available to host Distributed Energy Resources (DERs).

This document serves as the Final ICA WG Report of the Integration Capacity Analysis (ICA) Working Group (WG) to the California Public Utilities Commission (CPUC). The Working Group is comprised of the California IOUs and interested stakeholders. A complete list of participating Parties may be found in the Appendix. This report summarizes the development of the ICA to date, the recommended ICA methodology for the Investor Owned Utilities (IOUs) to implement across their service territories on the first system wide roll out, an implementation timeline, and recommendations on how to improve the methodology through the long-term enhancements via the ICA WG. This report also provides recommendations on how the ICA results may be used to inform decision-making on the part of the Commission, utilities, providers of distributed energy resources, and customers.

At a high level, these include recommendations in the following categories:

1. **Uses of ICA:** The WG identifies two primary use cases for the ICA. The first and most developed use case for the ICA is to improve interconnection, which includes a more automated and transparent interconnection process and the publication of data that helps customers design systems that do not exceed grid limitations. The second, and currently less developed use case for the ICA, is to utilize ICA to inform distribution planning processes to help identify how to better integrate DERs onto the system. The Final ICA WG Report outlines near and long term methodological refinements to enable the use of ICA within the interconnection process, and lays out considerations for the planning use case, with a goal of developing methodology recommendations for use within the planning context in the near-term (and in coordination with ongoing planning proceedings at the CPUC).

2. **Development of Common IOU methodology**: The ACR stated that the CPUC envisioned approving a final ICA methodology common across all utilities through an early 2017 Decision. The IOUs conducted the ICA using two separate methodologies in Demo A, known as “iterative” and “streamlined”. A majority of WG members, including SCE and SDG&E, recommend that the IOUs use the iterative methodology for interconnection purposes, assuming added refinements detailed further in this report can be achieved at a reasonable cost. PG&E recommends a “blended” approach using both methods for interconnection[1]. The WG believes the streamlined methodology may provide value in the planning process, and will continue to consider it while defining the uses of the ICA in system planning. The two methodologies each may be more

[1] See PG&E’s final Demo A report: http://drpwg.org/wp-content/uploads/2016/07/R1408013-PGE-Demo-Projects-A-B-Final-Reports.pdf

suited to specific circuits, situations, and tool capabilities and that blended use of both methods may be considered for future use.

3. **Refinements to ICA methodology**: The WG made recommendations on how the ICA methodology may be refined. These include both recommendations directly responding to the discrete activities identified by the ACR (*see Section 10*), as well as recommendations made after reviewing IOUs' final Demo A reports. Some of these latter recommendations fall under the ACR-defined WG purpose of "continuing to improve and refine the ICA methodology." Some of these recommendations endeavored to weigh utilities' cost estimates within the context of necessary granularity to meet the identified use case, but efforts to do so are limited by the available estimates for review and limited discussion to-date. Several of these recommendations are not consensus items. Those applicable to the first system-wide rollout of ICA for the interconnection use case are identified in Section 13, Table 1.

4. **Timeline:** As outlined in Section 3.3, the IOUs recommend that the first rollout of ICA methodology across their entire distribution service territories begin 12 months after a CPUC Final Decision on a common Commission-approved methodology, due to the number of processes required before ICA is ready for full implementation. At least one stakeholder offers a second opinion and recommends that IOUs begin the implementation process within 12 months of the Final Demo A WG Report filing.

5. **Modifications to ICA methodology and schedule:** WG recommends that the Commission establish two processes to incorporate modifications to the ICA which are made during the long-term refinement phase of the ICA WG:
    1. The CPUC should adopt a process whereby IOUs consult with the WG, followed by a Tier 1 advice letter, to approve ICA methodology changes as IOUs continue to enhance and incorporate refinements.
    2. The CPUC should adopt a process whereby requests for modification of scope and schedule due to unforeseen circumstances during system-wide implementation be sought through Tier 1 advice letter.

2 Introduction and Background

Overview

Assembly Bill 327 (Perea, 2013) established Section 769 of the California Public Utilities Code, which requires the California Investor Owned Utilities (IOUs) to prepare Distribution Resource Plans (DRPs) that identify optimal locations for the deployment of distributed energy resources (DERs). In August 2014, the California Public Utilities Commission (CPUC, or Commission) began implementation of this requirement through Rulemaking (R.) 14-08-013, the Distribution Resources Plan (DRP) proceeding. A Ruling from the Assigned Commissioner in November 2014 introduced the Integration Capacity Analysis

(ICA) as a tool that would support the determination of optimal locations by specifying how much capacity for integrating circuits on the distribution system may have available to host DERs.[2]

Pursuant to Commission direction, the IOUs filed their DRPs as Applications[3] , including a proposal to complete a Demonstration of their ICA methodology ("Demo A"). Stakeholders provided input on the IOU proposals, leading to an Assigned Commissioner's Ruling (ACR) issued in May 2016. That guidance authorized a demonstration project of the ICA, requiring the IOUs to meet the following nine functional requirements:

1. *Quantify the Capability of the 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*
7. *Use Time Series Models*
8. *Avoid Heuristic approaches, where possible*
9. *Perform the complete ICA analysis for all feeders down to the line section or node on two Distribution Planning Areas (DPA).*[4]

The ACR also established the ICA Working Group (WG) to monitor and provide consultation to the IOUs on the execution of Demonstration Project A and further refinements to the ICA methodology. CPUC Energy Division staff has oversight responsibility of the WG, but it is currently managed by the utilities and interested stakeholders on an interim basis. The utilities jointly engaged More Than Smart (MTS), a 501(c)3 non-profit organization, to facilitate the WG. The Energy Division may at its discretion assume direct management of the working group or appoint a WG manager.

Between May 2016 and March 2017, the WG met 18 times. The WG has benefitted from contributions by a large range of stakeholders who are listed in the Appendix. The WG expects to continue its efforts through the next six months as it begins to address long-term ICA refinement.

In December 2016, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) submitted their final Demo A reports, representing a substantial milestone for the demonstration projects.[5] These reports summarize Demo results, lessons learned, and the IOUs' recommendations on the methodology selection and feasibility of implementation of the ICA across the entire distribution system.

The WG collectively discussed the IOU final Demo A reports in January, February, and March. Many of those discussions informed the recommendations found in this report.

---

[2] Assigned Commissioners Ruling, November 2014.
(http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M141/K905/141905168.PDF)
[3] http://www.cpuc.ca.gov/General.aspx?id=5071
[4] Assigned Commissioner's Ruling, May 2016.
(http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF)
[5] IOU Final Demo A Reports can be found at: http://drpwg.org/sample-page/drp/

Scope and Process

The "Working Group" references all active parties participating in ICA WG meetings, which include the IOUs, government representatives, DER developers, nonprofits, and independent advocates and consultants. All meeting dates and topics covered, as well as all stakeholder groups attending at least one meeting or webinar of the ICA WG, are described in Appendix A. This report is the product of significant written edits and contributions from the following organizations:

- CPUC Energy Division (ED)
- Office of Ratepayer Advocates (ORA)
- California Solar Energy Industries Association (CALSEIA)
- Clean Coalition
- Community Environmental Council
- Independent Advocates
- Interstate Renewable Energy Council (IREC)
- Pacific Gas & Electric (PG&E)
- San Diego Gas and Electric (SDG&E)
- SolarCity
- Solar Energy Industries Association (SEIA)
- Southern California Edison (SCE)
- The Utility Reform Network (TURN)
- Vote Solar

The ICA WG met regularly to discuss the proposed methodology for Demonstration A and to review the final Demo A reports. A full summary of WG documents including meeting agendas, presentation slides, and participant list is included in the Appendix.

All three IOUs submitted their Final Demo A Reports at the end of December 2016 in compliance with the ACR. The ACR additionally specified that maps and downloadable data should be made available for stakeholder review[6]. These reports lay out in detail the assumptions and calculations used within the ICA methodology. Additional information about the methodology was shared during the subsequent WG meetings which dived into the details on numerous aspects of the process that had not been fully detailed in the reports. Additionally, the IOUs each separately made recommendations on which methodology (*i.e.,* using a streamlined, iterative, or blended approach) to use going forward in a system-wide rollout of ICA. WG stakeholder review and further discussion of these recommendations led to different conclusions in some areas.

The ACR additionally specifies multiple items the WG should focus on to continue refining the ICA methodology. The WG filed an interim long-term refinement report in December 2016 detailing work to-date on those items, and sorting topics into a tiered system to develop a rough schedule for WG work in 2017. After reviewing the IOUs' final Demo A reports, the WG identified additional items to refine the ICA in support of the first system-wide rollout (*see Section 14: Next Steps*). The WG will prioritize the

[6] At the time of the filing of this report, stakeholders have reviewed SCE's maps and downloadable data, and some parts of PG&E's (required information was provided for substation, customer breakdown percentage, existing generation, queued generation, and total generation). SDG&E's maps and downloadable data were made available on March 10. SDG&E realizes this does not provide sufficient time for stakeholders to review results prior to submission of the Final ICA WG Report.

development of this list as an action item during the beginning of its long-term refinement work. For the WG, "long-term refinement" means WG activity 6 months after the filing of the Final ICA WG Report, beginning March 15, 2017.

To this end, the WG agrees to identify items where parties have built consensus, and to identify where there is non-consensus by particular parties and alternative proposals have been made.

3 Recommendation Categories

The report details the WG's recommendations for selection of the ICA methodology and further refinements. Where possible, recommendations are mapped to the specific section in the ACR.

The WG recommendations are in these categories:

1. Use cases of ICA
2. Development of common IOU methodology
3. Schedule and timelines
4. Review of cost estimates
5. Frequency of updates
6. Presentation of values
7. Standardization of methodology
8. ACR requirements
9. Short-term activities
10. Long-term refinement activities
11. Modifications to scope and schedule
12. Additional cost recovery
13. Recommendation summary table

These recommendations are based on WG discussion of IOU Demo A Reports from May 2016 to March 2017, and focus only on additional areas of refinement discussed through WG meetings rather than providing a full summary of Demo A projects. Areas where this report does not comment on methodology outlined in IOUs' Final Demo A Reports are considered as support for, or non-opposition to, methodological choices made for Demo A. Readers of this report should refer to the IOU Final Demo A Reports for additional detail on how ICA methodology was tested under ACR requirements.

4 Use Cases of ICA

The WG agreed to identify the specific uses of ICA and make recommendations on ICA based on concrete use cases, to the full extent possible. The WG expects that methodological considerations regarding frequency of updates, hourly load profiles, the basic methodology (streamlined vs. iterative), and other modeling options, may change based on the intended use of ICA.

At a high level, the WG has so far identified two uses of ICA:

1. **Inform and improve the Rule 21 interconnection process.** In the interconnection use case, ICA information may be used to update Rule 21 interconnection procedures and improve the interconnection processes. The results can also be used to better inform proper siting of

projects prior to entering the interconnection process. The WG recognizes that the interconnection process changes must be made via an appropriate Rule 21 proceeding.

2. **Inform and identify DER growth constraints in the planning process.** In the planning use case, 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 various DER growth scenarios.

The WG report outlines methodological refinements to enable the use of ICA within the interconnection process as determined by a future Rule 21 proceeding, and lays out considerations for the planning use case with a goal of developing methodology recommendations for use within the planning context.

These two use cases of ICA are described in further detail below:

1. **Informing interconnection siting decisions and facilitating an eventual automated and transparent interconnection process**

   The CPUC's Final Guidance on DRPs document calls for the "dramatic" streamlining of interconnection as one of the key purposes of the DRP.[7] ICA results can also 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. The WG expects that future Rule 21 proceedings will closely coordinate with the development of ICA to implement the recommendation in this report. Thus, the WG proposes that the Commission adopt an interconnection use case and that it include the following considerations, pending discussion under a still-to-be opened Rule 21 proceeding or equivalent. Utilities also specifically point out a need to coordinate the application of ICA with the need to install the required interconnection facilities. The WG identifies the following features as the core components of the interconnection use case:

   1. Developers should be able to submit a Rule 21 Fast Track application for DER interconnection up to the identified ICA value at the proposed point of interconnection, based on ICA figures shown on the map, changes in queued DER since the last map update and in the underlying data, and be able to pass those screens representing criteria the ICA has evaluated. The Rule 21 proceeding should identify processes and procedures which are required to support safety and reliability, while maximizing the ICA values to improve the interconnection process including, but not limited to, procedures associated with the evaluation procedures to account for frequency of updates, queued generation, ICA value at the time of interconnection, and resolution of screens not addressed by current ICA methodology.
   2. The ICA values identified at a point of interconnection are expected to replace and/or supplement the size limitations in the Fast Track eligibility criteria and will be able to address and/or improve the technical screens in the Rule 21 Fast Track process which are part of the ICA methodology. These include: screens F (Short

[7] "Final Guidance Assigned Commissioner Ruling on Distribution Resource Plans. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5108

circuit current contribution); M (aggregate generation less or equal to 15% of the line section peak load); G (short circuit interrupting capability); O (power quality and voltage fluctuation); and N (penetration test). With few exceptions, interconnection customers should be able to use the ICA value at their point of interconnection to know whether a proposed project will pass these screens in the Fast Track process. In the near-term, there will be additional screens that still need to be evaluated due to data not currently analyzed in the ICA.

3. The Rule 21 proceeding should develop a process to incorporate future enhancements to ICA which are developed in the DRP proceeding. These future enhancements would potentially address other screens such as screen L (transmission dependency/stability test), screen P (safety and reliability) and evaluation of single-phase lines and other advanced functions, which are pending additional information, modeling, and study through ICA long-term refinements.
4. The published ICA value used for the interconnection review should be the same ICA value shown on the online maps and in the underlying data, accounting for discrepancies which may occur due to queue changes and frequency of map updates.
5. The ICA shall be updated frequently enough to allow for an eventual automated and transparent interconnection process for projects that are a proposed size below the ICA value at their point of interconnection, taking into account changes in the project queue. There are multiple opinions on frequency of updates (*see Section 8: Frequency of Updates*).
6. The ICA should provide hourly data about hosting capacity limitations that enables a developer to design a system that takes full advantage of the available hosting capacity at their proposed point of interconnection. The use of this information in the interconnection process will require verification that the proposed operational profile meet the ICA hourly limitations. It may also require some additional communication and operational visibility provided to the utility. As Rule 21 refinements are made, and greater resolution is provided on the cost of a more data intensive ICA (i.e., more hours analyzed), a more granular hourly profile may be needed and justified.

2. Informing the Distribution Planning Process and Decision Making

The WG determined that there is a role for a planning use case for the ICA, as it may be possible that the ICA can help determine and guide where and when future integration capacity is a limitation, among other possible planning uses. The ICA results may also guide sourcing and procurement of DER solutions with additional locational granularity in the future. The three IOUs all propose to use the streamlined methodology in the planning context, as the iterative methodology creates a large amount of data, and requires considerable resources to conduct multiple scenario analyses. However, many components of this use case remain undefined, due to multiple ongoing efforts in other CPUC proceedings that will inform how ICA will be used in system planning, as well as the need for further clarity into the utility annual planning process itself. Further, the multiple ways ICA may be incorporated into planning (from guiding grid modernization investments, to how DERs may be evaluated as solutions in the Integrated Resource Planning process (IRP)) are quite variable in the level of detail (e.g., granular hourly profiles, frequency of updates, etc.) they require from the ICA methodology. Because many open questions remain about the precise definition of the planning use case, the WG was not able to make specific recommendations regarding the appropriate methodology (or the details of that methodology) that would ultimately serve this use case best. Finally, the WG determined that the need to incorporate ICA in planning, while highly important, is less immediate when compared to the use of ICA in expediting the interconnection of DERs through Rule 21 modifications.

Thus, the WG proposes to further define the planning use case as a key high-priority long-term refinement issue beginning March 15, and outlines several considerations for the planning use case going forward:

1. Further refinement of the planning use case will allow the WG to form a specific list of uses of ICA in planning, evaluate the methodological needs for each use case, and determine whether the iterative or streamlined method may better serve that use case, and define what, if any, changes to these methodologies may be necessary to best serve the use case.
2. Some of the steps the IOUs will take to implement the first system-wide rollout of ICA for the interconnection use case will also eventually benefit the deployment of ICA for the planning use case.
3. Achieving the ICA values for these identified uses may require a blended approach (using aspects of both iterative and streamlined methodology) based on future discussion on planning use cases. The WG appreciates and understands the benefits that employing a streamlined method offers regarding computational resources, and looks forward to better evaluating its application to the planning use case in further WG meetings.

The WG requests further guidance from the CPUC on uses of ICA within the planning context, and the role the WG is expected to play in developing uses that may be included in other proceedings or DRP tracks. These concepts may need to be discussed and refined in Track 3 of the DRP proceeding. To date, some members of the WG have suggested the following discussion items as a starting point, though these are not met with consensus by the full WG:

- The scale, pace and prioritization of ratepayer funded grid modernization investments may be guided by projected ICA values. ICA may be one tool to guide and prioritize ratepayer-funded investments for grid modernization as determined by other proceedings.
- IOUs may use the ICA to evaluate DER as potential solutions to address needs identified in the IRP process.
- The current system capacity revealed through the ICA may be combined with location-specific projections of DER growth (i.e., DER growth scenarios) to project hosting capacity needs.
- IOUs and stakeholders may consider the ICA and LNBA may in tandem to identify opportunities where additions to hosting capacity can enable DER growth and avoid more costly distribution system upgrades.

5 Development of Common IOU Methodology

5.1 Overview

Within Demo A, the IOUs tested the ICA under two separate methodologies, referred to as the "iterative" and the "streamlined" methodologies. The iterative ICA method is based on iterations of successive power flow simulations at each node on the distribution system, whereas the streamlined method uses a set of equations and algorithms to evaluate power system criteria at each node on the distribution system. The iterative method parallels detailed study procedures used within the interconnection process relying on direct simulation of resources. During implementation of Demo A projects, the IOUs tested the variance between the iterative and streamlined analyses, as well as among the three IOUs, using a reference circuit.

The IOUs presented a comparison summary of Demo A results using both methodologies, and outlined recommendations within their Final Demo A Reports on which methodology, or portions of methodology, they believe should be employed in a full system-wide rollout. The rationale behind these recommendations is based on lessons learned from the Demo projects and full system-wide implementation considerations, computational efficiency, capability of CYME/Synergi software, and costs. [8]

5.2 Streamlined method

The streamlined method uses an abstraction approach, applying a set of equations and algorithms to evaluate power system criteria at each node on the distribution system. The streamlined method first performs a baseline power flow and a short-circuit simulation to acquire the initial conditions of the circuit that will be used in the streamlined calculations. These conditions can be, but are not limited to, electrical characteristics such as thermal ratings, resistance, voltages, current, fault duties, etc. The streamlined method then evaluates the full set of criteria, including thermal, voltage, protection, and safety limits independently to determine the maximum hosting capacity at a given node or component of the system. Simpler methods utilized in the streamlined methodology may not capture some of the more dynamic effects on the more complex circuits. However, the ability to utilize simpler equations and algorithms can enable faster computations on more scenarios and hours.

5.3 Iterative method

The iterative method performs iterative power flow simulations while varying the DER level at each node on the distribution system to determine the maximum amount of DER that can be installed without triggering thermal or voltage criteria violations. Fault current simulations are used for protection criteria not dependent on power flows. Due to the large number of iterations required, iterative analysis can result in longer processing times, especially when expanded to large numbers of distribution circuits. However, the use of an iterative simulation parallels what IOUs would perform as part of a detailed interconnection study, and therefore produces more accurate results. This technique

[8] Please refer to final Demo A reports.

is also expected to provide more confidence in representation of integration capacity in more complex circuit conditions.

The iterative method adds a fixed incremental level of DER in each grid location until an ICA violation is triggered. In Demo A, this incremental level was up to 500kW. A smaller increment could add value to the ICA, but would increase processing time. The incremental DER value may be an additional methodological detail to be considered in future iterations of ICA.

5.4 Recommendations

The WG recommends a consistent approach be used across all three IOUs to facilitate future advancements and maintain consistency across the state, and in accordance with the Commission guidance ruling.

After multiple meetings, the WG developed two different recommendations:

1. A majority of the WG (SCE, SDG&E, and all WG stakeholders involved in the active development of this report) recommended that the iterative methodology be used for the interconnection use case (with the following refinements detailed in this report) to update the interconnection maps, improve the interconnection process and be deployed in the first system wide deployment of ICA. Within their Demo A reports, SCE and SDG&E supported the use of iterative method as appropriate means of supporting the interconnection processes, as the iterative method parallels the study procedures followed in the Rule 21 process, and considered that future changes to Rule 21 may be potentially be significantly simplified with the use of the iterative method.

2. PG&E instead recommends the use of a “blended” approach, using both the iterative and streamlined methods within the interconnection use case. The streamlined method would be applied to an overall analysis for the whole system (and be the results shown on the map and in the underlying data), and iterative would be utilized to analyze specific conditions within the interconnection process. This approach could result in a more cost-effective implementation given that the iterative method requires additional IT and engineering resources to complete. The blended approach is fully detailed in PG&E’s Final Demo A Report.[9]

PG&E’s Argument Supporting the Blended Approach:

PG&E’s Demo A report explained that adopting the application-based iterative and system-wide streamlined recommendation would allow PG&E to more efficiently use existing resources and tool capabilities. Additionally, PG&E states that the blended approach better parallels an efficient tiered Rule 21 process that has proven to be a major success in California and promotes an efficient and accurate interconnection process. PG&E notes that there are application-specific components within interconnection that can’t be considered proactively and thus can only be automated within the interconnection process, not through ICA. PG&E notes that if full automation is desired, then focus

[9] http://drpwg.org/wp-content/uploads/2016/07/R1408013-PGE-Demo-Projects-A-B-Final-Reports.pdf

must shift to automating more of the interconnection process versus the proactive ICA, which can only improve portions of the interconnection review.

PG&E notes that adoption of this blended approach would require fewer engineering resources for PG&E. PG&E projects that if iterative, along with recommendations regarding planned projects and pre-existing conditions, is required for use in the maps and in the interconnection review, then it would need a new team to manage the ICA process, SCE and SDG&E do not share this opinion. PG&E projects if streamlined is adopted for system-wide updates and the iterative approach is adopted more efficiently on an application basis, then it is projected that the new work load can be more efficiently managed with current engineering resources.

PG&E is also undergoing existing planned work on modifications to its gateway to (1) utilize the new GIS system implemented in 2016, (2) expand the gateway to include substation models, and (3) expand its ability to include service transformers in the models. If recommendations require the incorporation of planned modifications and automated iterative across the whole system, then significant additional work would be required on the gateway and could postpone work to include substation and service transformers. Also, if PG&E's recommendation of application only based used of iterative is not adopted, then more engineering resources would have to be hired and trained in order to perform the regular iterative ICA analysis. Adopting the application-based iterative and system wide streamlined recommendation would allow PG&E to more efficiently use existing resources and tool capabilities (*for further explanation, see PG&E's final Demo A report*).

The Argument Supporting the Use of the Iterative Approach for Mapping and Interconnection Processing:

Other members of the WG discussed application of the "blended" approach as suggested by PG&E and 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 engineers and would enable the ICA information displayed on the map to be the same as what is applied in the interconnection process. If the maps and data are derived from the streamlined method, which Demo A demonstrated is inaccurate in too many cases, then interconnection applicants would not be able to rely on this information and would be left in their current business-as-usual situation, where obtaining accurate interconnection information requires a manual review by the utility. These other members of the WG consider this to be insufficient progress.

The other members of the WG appreciates that PG&E is in a different position from the other utilities with respect to the rollout of its models and software, and shares PG&E's concern about how it will implement the iterative process on its system in light of the work planned on its gateway and other concerns. However, the WG believes that a consistent methodology is a fundamentally important principle, one required by the Commission in its Guidance, and is necessary to avoid a slippery slope of further diversion once rolled into the Rule 21 process. Additionally, the WG discussed that there may be reasonable ways to reduce the data intensity while utilizing more efficient computing resources to address concerns regarding computational intensity of the iterative method. For example, IOUs could look for additional solutions in their efforts to reconcile their data using the iterative approach. In the long run, it seemed likely to the majority of the WG that the costs of the computing issues could be reasonably managed as technology and understanding of the ICA methodology advance.

The WG also recommends that the ICA WG continue to evaluate the streamlined method for potential use in the planning use case. Given that uses of ICA within planning are still being evaluated, the WG recommends that further discussion is needed to determine the appropriate ICA methodology for the planning use case, and that continued discussion of the use of the streamlined method to support the planning use case be part of long-term refinements to ICA.

6 Schedule and Timelines

6.1 Timeline for implementation

Following the completion of Demo A, the IOUs plan to perform final system-wide implementation of ICA. The WG engaged in multiple discussions surrounding expediency around this implementation, given the size and complexity of this project.

Stakeholders and the IOUs have separate recommendations regarding when the IOUs should implement the ICA across their service territory. Multiple stakeholders involved in the drafting of this report, including IREC, SEIA, and Vote Solar have expressed no preference in recommendations regarding implementation timeline. In both recommendations, the ICA methodology should include the identified short-term recommendations from the final report.

Proposal 1: Implementation within 12 months of a PUC Final Decision on final ICA methodology.

The IOUs understand the urgency of implementing an approved ICA methodology system wide and are committed to implement the ICA Methodology in an expeditious manner, given the need to implement a very large and complex project which has not been attempted by any utility. For reference, in Demo A, SCE performed the ICA on 82 distribution feeders in 4 months. In the system wide implementation, SCE will need to implement ICA on more than 4,500 distribution feeders, an amount which is exponentially higher in magnitude with a significant reduction in time compared to what was done in Demo A (Demo A: 21 circuits/month, System implementation: 375 circuits/month).

While a Final Decision is pending, the IOUs will continue to work on preparation activities, including preparation of network models, data sources, work force plans and implementation procedures. Once the CPUC issues a Final Decision, IOUs anticipate 12 months will be necessary for implementation.

Additional details on which IOUs work activities will begin prior to and after the Final Decision are outlined below, as prepared by SCE and applicable to all three IOUs:

Work to commence while a Final Decision is pending:

- **Model creation and validation:** SCE engineers to create distribution system models. Activity can start prior to a CPUC Final Decision, but it is estimated to last 10 months.
- **Preparation of data sources:** Preparation of data sources such as, SCADA Historian, GIS, and Distribution Management System is required.

Work to commence after decision (12 months):

- **Implement ICA methodology:** SCE estimates 4 months of development once final ICA Methodology is established. Work cannot start prior to CPUC Final Decision, as development requires all assumptions and functionality be outlined prior to start of solution design. In addition, based on Demo A work, various iterations of testing are required to stabilize code (e.g., troubleshoot bugs) to render solution production ready. Code will not be stabilized until after various distribution circuit models have been analyzed. Vendor engagement is required.
- **Run ICA**: Perform the ICA on the distribution system models. Based on the ICA Methodology requirements (e.g., number of hours, frequency of updates) computing resources need to be configured and computing resource management systems may need to be developed. Work with vendor community is required.
- **Quality assurance and control:** Quality control and quality assurance systems and processes need to be designed, developed, and implemented to support ICA methodology implementation activities, and to support SCE in the publication of most accurate results.
- **Publication of results**: Develop interfaces between ICA results databases, mapping databases, and other data sources required by a CPUC Final Decision. Edit map symbology to meet ICA requirements.

Separately, PG&E recommends that the ICA be implemented by June 2018, to coordinate with PG&E's planning process (currently distribution planning analysis and engineering review occur in the January to May timeframe). PG&E notes that if the CPUC adopts PG&E's recommendation to use the blended approach ("streamlined" method for system wide analysis and the "iterative" method on an as-requested or pre-application basis), then it is expected that fewer engineering resources are needed to implement this efficient approach.

IOUs strongly recommend that the appropriate time to complete full system wide implementation of ICA be 12 months following a CPUC Final Decision. This will ensure that IOUs can implement the appropriate methodology without the risk of losing valuable engineering work if the Proposed Decision is different than anticipated. Additionally, IOUs will continue to prepare those elements, such as preparing network models, data sources, work force plans and implementation procedures, that are needed for full implementation before a Final Decision is provided.

Proposal 2: Implementation within 12 months of ICA WG Final report. CALSEIA recommends that the IOUs begin the implementation process following the publishing of the ICA Final WG report, and finish implementation within 12 months of final report submission.

6.2 Recommended regulatory process

The WG recommends that the Commission establish two processes to incorporate modifications to the ICA both as part of the implementation of ICA system wide on its first rollout and as future enhancements are added to the methodology. These processes should balance the need for flexibility in implementation and in following appropriate CPUC practices:

1. **The CPUC should adopt a process whereby IOUs consult with the ICA WG, followed by a Tier 1 advice letter, to approve ICA methodology refinements:** As the utilities continue to refine and enhance the ICA methodology through long term enhancements

to ICA and consideration of future refinement studies, such as inclusion of smart inverters, single phase line sections and transmission impacts, it is requested that the Commission establish a process to allow the ICA WG to collaborate and determine how enhancements to the methodology are to be deployed system wide. The WG views the ICA methodology as one which will continue to evolve in an expedited and effective manner. This process should provide flexibility to phase in refinements within boundaries established by the CPUC.

2. **The CPUC should adopt a process whereby requests for modification of scope and schedule, due to unforeseen circumstances during full system rollout, be sought through a Tier 1 advice letter:** The methodology and refinements recommended in this report are based on the best available knowledge of software and tool capabilities, costs of implementation, and complexity of the project through review of Demo A Final Reports and subsequent WG discussions. Further, there are several meaningful recommendations made in this report that were not required to be tested as a part of Demo A, but were discussed among the WG as part of its direction from the ACR to "improve and refine the ICA methodology." For these recommendations, the WG engaged in discussion regarding the need for changes, and the practical feasibility of incorporation within either the initial system-wide rollout, versus establishing as longer-term goals. Given the scope and complexities of system wide implementation of ICA, the WG acknowledges that new challenges and limitations may surface that are not possible to predict at this time, but may arise during full system rollout be sought through a Tier 1 Advice Letter.

7 Review of Cost Estimates

After reviewing the results of the Demo A, the WG determined it would be additionally necessary to access how to best deploy ICA methodology with sufficient granularity to meet the use case, while acknowledging considerations regarding computing time and costs. The WG had identified inaccuracies in the streamlined method results during its review of Demo A. Understanding that the majority of the WG supported the use of the iterative method for the interconnection use case (*see Section 4: Use Cases*), the WG began discussions to determine how to best deploy the iterative approach in a manner that would achieve sufficient granularity in the calculated ICA, while also balancing the computing time and costs.

There are at least three different elements to consider when evaluating how to reduce the computational burden of the iterative method: (1) the methodology itself, (2) the software/hardware it is run on, and (3) the staff time associated with running the model and any manual efforts required to maintain it. As indicated in the Demo A Final Reports, each utility reported significantly different processing times for the iterative method (the WG notes that that this was not an apples-to-apples comparison as the utilities used different hardware, software, and computational efficiency measures in their Demo A results). In slides prepared for the WG meeting on January 6th[10], the utilities reported the following times on average per feeder: PG&E - 23 minutes, SCE - 83 minutes, and SDG&E - 1,620 minutes.

[10] http://drpwg.org/wp-content/uploads/2016/07/ICA-WG-Jan-6-slide-deck.pptx

- **Methodology:** The IOUs identified a number of factors that could be modified within the iterative methodology in order to reduce the computational burden. These included: reducing the number of nodes; reducing the number of hours in the load profile; reduction of the limitation categories evaluated on strong feeders; the frequency that the analysis was run; and whether it was run system-wide or on a more "as needed" or "case-by-case" basis. Note the utilities did not all deploy each of these computational reduction strategies due to time and other factors in Demo A, which may be one factor in the difference in computational time seen in the results. The WG also identified a need to understand the computational effect of allowing voltage regulating devices to "float" instead of remaining "fixed" or "locked" in the model. Other than the reduction in nodes and limitation on categories (which the WG concluded were logical computational savings that should be implemented since they did not have a significant impact on the results), each of the other factors could affect the ultimate usability of the ICA to achieve the interconnection use case goals and the accuracy of the ICA that is ultimately calculated. WG discussions on these methodological choices are detailed further in this report.

- **Hardware/Software**: Each IOU used a different combination of software and hardware to run the Demo A results. For example, SDG&E indicated that the "streamlined simulation was performed on a server based computer, while the iterative was performed on office laptop computers.[11]" PG&E "used a combination of local machines and servers which relied on many parallel computing streams for the analysis.[12]" SCE's report did not specify the hardware used to run the models in their Final Report, but they explained to the WG that SCE utilized local servers to run the results. In addition to the differences in hardware, the use of CYME or Synergi and other related software also impacted the computational burden of Demo A.

- **Staff Time:** An additional factor that did not get covered in as much detail in the Demo A Final Reports or WG discussion was amount of staff time required to run and maintain the models depending upon the methodology selected. PG&E in particular indicated that running the iterative method for the interconnection use case on their system could require significant increases in engineering staff support, as they are not currently able to maintain their models in an automated fashion.

Recognizing that the ultimate formula of these different factors selected for the final ICA methodology could have a potentially significant impact on the costs associated with deploying the ICA, the WG sought cost estimates that would help illuminate which factors have the greatest effect on costs, and assist both the WG and the Commission in making an informed recommendation for how to deploy the ICA for the interconnection use case. Stakeholders of the ICA WG requested[13] that the IOUs provide a base case estimate of the costs to run a plausible scenario for each of the two methodologies and then identify the cost factors associated with a set of defined sensitivities. For the iterative method, the WG asked for information on the following sensitivities: (i) Frequency of running the model; (ii) Hours (i.e. 96, 576, 8760); (iii) Movement of voltage regulating devices; (iv) Method of updating a system-wide ICA (i.e. a "case-by-case" basis or on an "on-demand" basis). The WG also asked the utilities to identify (i)

---

[11] SDG&E Demo A Final Report, pp. 43
[12] PG&E Demo A Final Report, pp. 143.
[13] See stakeholder recommendations submitted on 1/30. http://drpwg.org/wp-content/uploads/2016/07/WG-Recs-and-Questions-1.30-002.docx

what costs are one-time costs, (ii), which costs are variable but will decline over time, and (iii) which costs are variable, increasing with increased levels of computational intensity.

On February 27th, the IOUs provided the following table that summarized their cost estimation efforts, and subsequently provided a list of factors that went into those cost estimates.

Table 1: Cost Estimates Comparison of Multiple ICA Implementation Scenarios

Iterative	Cost ($000) (Year 1)		Cost ($000) (Beyond Year 1)	
Scenario 1: 96 loading conditions, monthly updates ICA WG Iterative Methodology base case	**PG&E**	$2,040-$3,800	**PG&E**	$1,740-$3,050
	SCE	$3,300-$6,300	**SCE**	$1,400-$2,600
	SDG&E	$2,200-$3,300	**SDG&E**	$1,100-$1,700
Scenario 2: 576 loading conditions, monthly updates	**PG&E**	$2,990 - $5,300	**PG&E**	$2,690 - $4,550
	SCE	$3,800-$7,000	**SCE**	$2,200-$3,900
	SDG&E	$2,400-$3,500	**SDG&E**	$1,500-$2,200
Scenario 3: 96 loading conditions, weekly updates	**PG&E**	$4,130-$7,100	**PG&E**	$3,830-$6,350
	SCE	$4,300-$8,100	**SCE**	$2,900-$5,200
	SDG&E	$3,100-$4,700	**SDG&E**	$2,200-$3,300
Streamlined	**Cost ($000) (Year 1)**		**Cost ($000) (Beyond Year 1)**	
Scenario 1: 8760 loading conditions, annual updates ICA WG Streamlined Methodology base case	**PG&E**	$1,480-$3,060	**PG&E**	$680-$1,560
	SCE	$2,000-$3,600	**SCE**	$600-$1,400
	SDG&E	$1,700-$2,500	**SDG&E**	$600-$900
Scenario 2: 8760 loading conditions, monthly updates	**PG&E**	$1,630-$3,360	**PG&E**	$830-$1,860
	SCE	$2,000-$3,600	**SCE**	$1,100-$2,100
	SDG&E	$1,700-$2,500	**SDG&E**	$900-$1,400
Scenario 3: 8760 loading conditions, weekly updates	**PG&E**	$1,810-$3,720	**PG&E**	$1,160-$2,470
	SCE	$3,300-$5,900	**SCE**	$1,700-$3,200
	SDG&E	$2,300-$3,500	**SDG&E**	$1,500-$2,200

These cost estimates consider resources to complete tasks required for system wide rollout implementation and for continue on-going support and maintenance. The typical tasks are outline as follows:

- **Model creation and validation**: typically includes 1) the creation of distribution system models by integrating data from multiple sources, including SCADA Historian, GIS, and Distribution Management System data; and 2) the validation of the distribution circuit models ensuring accurate modeling of the distribution system (i.e., validate that models reflect actual planned conditions).
- **Implement ICA methodology:** typically includes 1) implementation of final ICA methodology on an enterprise-friendly system capable of handling large datasets; 2) development of databases, data structures, and processes; 3) implementation of algorithms and assumptions (e.g., pre-existing conditions); and 4) additional work with vendor community.
- **Run ICA:** typically includes 1) performing ICA on distribution system models and 2) working with vendor community and software licensing. Based on methodology requirements (e.g., number of hours, frequency of updates), computing resources need to be procured and configured. In addition, based on volume of data, computing resource management systems may need to be developed. "Stop and run" of ICA to troubleshoot problems is expected, proportional to the number of scenarios/loading conditions analyzed.
- **Quality assurance and control**: once ICA is complete, the results need to be evaluated for abnormal data due to divergence or modeling issues. These data can include ICA results that fail to converge, which will require manual troubleshooting by engineers.
- **Publication of results:** based on the final data attributes, volume of data, and frequency of updates, development work is required to update the mapping systems and integrate these to ICA results databases.
- **Periodic updates**: software development to support Tasks 1-5 to meet periodic update requirements as mandated by final ICA methodology, including automatic identification circuitry changes requiring ICA update, and end-to-end integration of processes and data.

WG discussions surrounding these cost estimates have led to separate recommendations regarding two methodological refinements in particular: 1) hourly load profile, and 2) frequency of updates. The IOUs discuss in their Final Demo A Reports whether utilization of load profile reduction methods can significantly improve ICA runtime performance, while still providing the required level of accuracy *(see Section 11.3: Computational Efficiency)*. IOUs additionally recommend that ICA is updated no more than on a monthly basis, and set a longer-term goal for more frequent updates as necessary to meet the uses of interconnection *(see Section 8: Frequency of Updates)*. Many stakeholders recommend maintaining a 576 hour load profile (as tested in Demo A) and that ICA results are updated on a weekly basis.

Further detail regarding the recommendation of a subset of WG stakeholders is detailed below. The IOUs recommend review of their Demo A Final Reports for full discussion and detail of their recommendation on hourly load profile, and how often ICA should be updated.

Stakeholder subgroup recommendation:
Written by Interstate Renewable Energy Council (IREC), on behalf of a stakeholder subgroup including CALSEIA, Clean Coalition, SEIA, SolarCity, Vote Solar

The WG appreciates that the utilities had limited time to prepare the cost estimates, and that some of the cost elements are hard for them to precisely predict, as they may be dependent on software vendors and other unknown factors associated with conducting a system-wide ICA for the first time. However, the stakeholders of the WG found the cost estimates to be lacking in sufficient detail to adequately guide the decision-making process. The estimates look at a limited number of scenarios without identifying the specific sensitivities associated with each factor (and only two conditions varied: the hours and frequency of updates). The estimates also provide very high ranges; in many cases, the top end of the provided range is nearly double that of the low end of the range. The estimates do not identify what costs may overlap or be duplicative with services or costs that have already been identified in other forums (i.e., in distribution system planning or DER integration cost estimates in the utilities' respective general rate cases). The costs are not broken out by category so that stakeholders of the WG could understand what portion of the costs are associated with corresponding variables (e.g., staff time vs. server costs, etc.) Finally, it is also very important to recognize that these cost estimates have not taken into account any potential cost savings associated with using the ICA to create a more efficient, and less manual, interconnection process. It is expected that over time, the utility engineering and administrative time associated with the interconnection process could be reduced through the use of the ICA and those savings should be considered in assessing the costs of ICA rollout.

With these limitations in mind, these WG stakeholders have the following comments about how these estimates have influenced this set of recommendations. First, this subset of WG stakeholders recognize that the costs of running the iterative method are higher than those of the streamlined method, but concludes that those costs are warranted in order to extract actual benefit from the ICA in the interconnection use case. For DER customers to be able to reduce the costs of project development, it is important to have transparent ICA results that will correspond to actual interconnection decisions. Correspondingly, utility costs associated with processing interconnection results will not be meaningfully reduced if the ICA results cannot be relied upon in interconnection decision-making. It will take time to fully implement and realize the cost savings associated with integrating the ICA into the interconnection process, but starting with the right foundation is important to achieving that long-term goal.

Second, while it does appear that costs associated with updating the ICA weekly are notably higher, the increased frequency is important to ultimately enabling a process whereby interconnection applicants can utilize the ICA information displayed in the maps and underlying data to accurately predict their ability to achieve an automated or semi-automated interconnection decision. The WG believes that monthly should be the very minimum frequency with which the ICA should be updated, but it is inclined to recommend that weekly updates be required from the outset. While the cost information is quite speculative at this point, the WG would like to see if the utilities could identify more efficient ways of updating the ICA on a weekly basis if truly tasked with that requirement.

Third, similar reasoning applies to the number of hours evaluated in the load profiles. One of the core improvements of ICA is moving from a process that only includes annual maximum or minimum values to a process that considers seasonal maximums and minimums. Since 96-hour data includes only two representative days per year, this is not a strong enough step toward improved granularity. The WG therefore recommends 576-hour data.

Thus, this subset of WG stakeholders recommend that the utilities be required to do an initial rollout of the ICA that aims to update any changed circuits on a weekly basis and that applies a 576 hour load profile. If the cost estimates provided by the utilities are accurate, the costs associated with initial rollout will be higher under this scenario compared to other options, but the marginal increase may be estimated at $1-4 million dollars per utility which, in the big picture, is a quite modest cost (i.e. a one-time cost of a few cents per electric customer). It is the yearly maintenance costs that are of greater concern, but it seems likely to these WG members that these costs are more speculative at this point and could fall over time as technology improves and internal efficiencies are identified - though the WG acknowledges this point is currently just speculation.

Thus, this subset of WG stakeholders recommend that the Commission require the utilities to document their processes and the costs associated with them in a granular manner for three years. Subsequently, the Commission should utilize that information to evaluate what the yearly maintenance costs are, and are likely to be going forward. At that point, the Commission can reevaluate whether the actual costs are justified based upon the applied experience and, if not justified, the frequency of the updates or the hourly profile (or other factors) could be adjusted accordingly. The Commission may also want to consider applying an overall not-to-exceed cost cap should the estimates turn out to be overly conservative.

8 Frequency of Updates

The WG recommends that ICA be updated frequently enough to allow for a meaningful impact to interconnection process for projects that are proposed below the ICA value at their point of interconnection. To meet this goal, members of the WG have different opinions on how often ICA should be updated.

The IOUs support system-wide monthly updates for the initial rollout with consideration of additional functionality and higher levels of frequency of updates in subsequent iterations, such as case-by-case updates, weekly or on demand updates contingent upon cost, funding and system capabilities. The additional envisioned condition-based updates requested by some WG stakeholders will require significant front-end coding and development to implement properly, and may create additional costs and/or delay the first system-wide implementation.

Other WG stakeholders believe that, at a minimum, system-wide ICA values should be updated annually and that specific ICA values be at minimum updated weekly to reflect new queued projects or other system changes above a defined threshold. Since the GIS databases of the utilities are updated weekly, this recommendation corresponds with those parallel updates. This would allow the ICA figure shown on the maps to provide the most accurate ICA to be used for interconnection requests. The ICA should be run system-wide as needed to reconcile local changes.

As a long-term vision, and not part of the ACR’s long-term refinement scope, some members of the WG envision that the ICA should be updated on a real-time or daily basis to the extent possible to allow the reflecting values to be used in an automated interconnection process. Future enhancement should work towards this goal, while considering issues such as the following in coordination with the Rule 21 proceeding:

- Development of automated interconnection studies which considers specific application information that cannot be known ahead of time to be reflected in ICA. Generation queuing, commercial operation dates, and planned work/transfers can all have a unique impact on certain locations in the system and currently must be considered application-by-application with manual engineering review.
- Stricter enforcement of applicant timelines and milestone provisions to prevent the risk of individuals claiming queue positions via speculative process.
- Costs associated with the work needed to develop necessary tools and procedures.

9 Presentation of ICA values

The WG recommends that the ICA information be presented in both online maps and downloadable data formats. The ICA information to be used in the maps and to be downloadable includes three ICA values with two separate applications of operational flexibility limitations. The three ICA values to be published are: (1) the uniform operation ICA value for generation (technology-agnostic ICA value), (2) the uniform operation ICA value for load (technology-agnostic ICA value), and (3) ICA value using a typical fixed PV production shape. The two applications of operational flexibility are described in further detail in *Section 10.4: Safety and Reliability*.

In total, six ICA values should be published:

Table 2: Published ICA Values in Maps

Uniform load ICA value, operational flexibility limit	Uniform load value, reverse power flow up to the substation low-side busbar
Uniform generation ICA value, operational flexibility limit	Uniform generation ICA value, reverse power flow up to the substation low-side busbar
ICA value using typical PV profile, operational flexibility limit	ICA value using typical PV profile, reverse power flow up to the substation low-side busbar

The WG will develop a standard PV generation profile to be used within the online map in time to be used in the first system-wide rollout of ICA. The profile will be sufficiently conservative to be relied upon for interconnection approval, and will include monthly variation in solar production. In addition, the IOUs developed an offline ICA Calculator that can be used to help determine ICA values at specific locations for user-defined DER profiles.

The ICA value used for the interconnection review should be the same ICA value shown on the online maps –thus, the ICA maps and underlying data should be updated with the same frequency as the ICA itself. Further modifications and procedures in future modifications in the Rule 21 process should take this into account.

10 ACR Requirements

10.1 Modeling and extracting power system data

The IOUs used either LoadSEER or an equivalent load forecasting analysis tool to develop load profiles at the feeder, substation, and system levels. In Demo A, IOUs aligned load allocation methodology with current interconnection practices, and further detailed how weather assumptions were incorporated through separate written responses[14].

Stakeholders of the WG posed questions on assumptions used in load forecasting, including questions on inclusion of weather conditions (e.g., temperature, irradiance, wind speed, concurrent with each hour of the load forecast). Because load forecasts are significant factors in forecasting grid conditions and which can influence ICA values, the WG recommends that the findings and recommendations from the CPUC workshop from Track 3, sub-track 1 on Load and DER forecasting, as well as all findings from this DRP sub-track, be incorporated as appropriate into the ICA methodology.

The WG additionally provides the following considerations, to help inform the Track 3 process:

- Stakeholders of the WG request additional transparency regarding underlying weather assumptions from which IOU high and low load hours are derived. Understanding the conditions underlying load forecasts is important if developers are meant to model DER performance to ensure hosting capacity limits are not violated.
- Currently, there are differences among the methodology employed by the three IOUs. Stakeholders of the WG would like to further understand reasons for methodological divergence.
- Within PG&E and SDG&E's methodology, some stakeholders would like to further understand whether the synthetic days created are sufficiently reflective of real conditions that would be experienced on the distribution system.

10.2 Power system criteria methodology

ICA results are dependent on the most limiting power system criteria. The four criteria used for Demo A are:

1. **Thermal criteria:** amount of additional load or generation that can be placed on the distribution feeder without exceeding equipment thermal ratings
2. **Power quality/voltage criteria:** steady state voltage violations and voltage fluctuation calculated based on system voltage, impedances and DER power factor. Violations outside of Electric Rule 2 and voltage fluctuation of up to 3% is part of system design criteria for all three utilities.
3. **Protection criteria:** amount of fault current at various protective devices factoring in contributions from DER.
4. **Safety/reliability criteria:** operational flexibility that accounts for reverse power flow issues when DER/DG is generating into abnormal circuit operating scenarios. Other limitations supporting the safe and reliable operation of the distribution system apply, including thermal overloads due to new configuration, and high or low voltage issues due to new configuration.

[14] http://drpwg.org/wp-content/uploads/2016/07/WG-Recs-and-Questions-SCE-PGE-SDGE.docx

The WG developed recommendations regarding the input assumptions for the power quality/voltage and the safety/reliability criterion, and anticipates the ICA methodology may change depending on its specific use case.

10.2.1 Power quality/voltage criteria:

The IOUs take various approaches to how they treat voltage regulating devices within the iterative methodology. Devices may be "locked", meaning that these voltage regulating devices do not adjust from one simulation to the next simulation in the ICA, or the devices can be "unlocked", meaning that these voltage devices adjust to maximize voltage profile from one simulation to the next. In the field, the voltage regulating devices are not locked, thus, by locking them in the model the calculated ICA will not accurately reflect field conditions. Currently, CYME software (used by PG&E and SCE) does not have the capability for "unlocked" operations allowing voltage control devices to adjust during ICA iterations (referred to as "float"), while Synergi (used by SDG&E) does have that capability. Through WG meetings, the IOUs explained that the CYME module used for Demo A locked voltage devices to better allow for modeling convergence. Although allowing devices to float more closely models real-world conditions, it adds to model complexity which increases divergence and runtime.

The WG is in consensus recommendation that voltage regulating devices should be "unlocked" within the iterative methodology, but are not in consensus with regards to process and timing of implementation which would allow the IOUs to enable this feature.

PG&E, SCE, and SDG&E recommend that for the first system-wide rollout, voltage regulating devices may be operated as applied in Demo A for each IOU (i.e. locked for SCE and PG&E, but allowed to float for SDG&E); The IOUs will work with software vendors to encourage the inclusion of an optional function to "unlock" the voltage regulating devices into the ICA modules, using a set of operational assumptions to be developed by the WG. As this requires action and commitment from vendors, assessment of impacts on runtime and analysis of ICA convergence (i.e., successful completion), this function should not be required for the first system-wide rollout but rather on subsequent rollouts when the function has been added to the power flow tools. The WG should continue to evaluate the value of not locking down the voltage regulator.

Other WG stakeholders recommend that IOUs work with software vendors to encourage its inclusion into the first system-wide rollout, given that Synergi has already shown the capability to do so, although CYME currently does not include this functionality. Stakeholders would like to first see whether this can be achieved before deferring to subsequent rollouts, though understand the need for delay if software vendors are unable to achieve this functionality in time.

The WG is open to continued discussion on the number of iterations of adjustment that are appropriate to determine the most accurate ICA value in an efficient manner. The effect of unlocking the voltage regulating devices was not included in the cost estimates provided by the utilities, though it is believed that SDG&E's estimates included that capability.

10.2.2 Safety and reliability, or "operational flexibility"

Demo A required two power flow scenarios for compliance with the ACR ruling which states that:

The demonstration is to employ two different methodologies of calculating the ICA values using:

a) *A scenario which limits power flow analysis to ensure power does not flow towards the transmission system beyond the distribution substation bus;*

b) *A scenario which determines the technical maximum amount of interconnected DERs that the system is capable of accommodating irrespective of power flow direction;*

To comply with the requirements of (a), the IOUs employed a method which prevented reverse flow of power across any SCADA-operated device on the distribution feeders. This method ensured that no power would be sent toward the transmission system as required by (a).

To comply with (b), the IOUs removed the limitation at the SCADA devices. This method provided an ICA value irrespective of power flow direction as required by (b).

Feeders contain open ties to other feeders in a distribution planning area that allow utilities to reconfigure circuits in response to loading condition, faults, or during system maintenance. Utilities maintain adequate “operational flexibility” to restore service to as many customers as possible and as quickly as possible during those events. This creates a challenge for evaluating hosting capacity because the reach of a DER system’s impact is not only along the circuit to which it is normally connected but also to all other circuits to which is could potentially be actively connected. For example, a DER system that could impact the power quality or thermal capabilities of an adjacent feeder should be considered even if the two items are not electrically connected during normal operating conditions.

The method of calculating the requirements for (a), where the utilities applied a “no reverse power flow across SCADA devices”, also served as limitation to provide an “operational flexibility limit” as required to maintain safety and reliability. This operational limit is used to maintain the operation of the distribution system without affecting distribution system reliability. That is, this methodology is designed to allow the highest levels of DER to be connected to the distribution feeder, without a reduction on operation of the distribution system. While the WG members agree with this general principle, some WG members also note that it has not been shown that retaining 100% operational flexibility in all cases is actually necessary to avoid safety and reliability concerns.

The intent of the safety/reliability constraint is to ensure that all operational flexibility is preserved when DERs are added to the grid. The SCADA-operated devices represent points at which the grid can be reconfigured, either permanently or temporarily. Because the ability of the grid to tolerate reverse flow depends on the configuration, by prohibiting reverse flow at these points, the ICA determines the DER adoption that produces no reverse flow in any configuration.

The WG recognizes that the operational flexibility criterion as implemented and described above is based on engineering practices that allow for calculation of the operational flexibility criteria across all circuits. However, the results of Demonstration A show that operational flexibility, as currently modeled by the IOUs, is a limit to ICA that produces results which ensure power quality to all customers and DER but may be overly conservative as a result. The WG recognizes that the method used to determine operational flexibility is heuristic in nature and encourages further discussion to determine non-heuristic methods to analyze operational flexibility.

The operational flexibility criterion based on no reverse power flow across SCADA-operated devices was implemented in Demo A because no other options for ensuring operational flexibility were identified and determined to be feasible given the current understanding of the capabilities of either the iterative or streamlined methods. The WG agrees that this was a reasonable short-term path, but believes that developing an improved approach to evaluating DER adoption limits related to operational flexibility should be an ICA development priority.

Additionally, the IOUs included in their Demo A projects a no-reverse-flow limit across voltage regulators, in some cases, in order to prevent power quality and voltage limits violations. This is because some voltage regulators currently on the system (both field and substation) may not be designed to allow for backflow, and existing control settings may not be adequate to properly manage increased levels of DER (some controls are programed to existing system conditions). Some voltage regulators and load tap changer (LTC) controls require fixed settings based on the load and DER connected to the voltage regulators. Thus, allowing reverse power flow on voltage regulators without verification of regulator's capability to accept reverse power flow may cause power quality issues for load and DER customers.

First System Rollout Recommendations

The WG agrees and recommends that the operational flexibility criterion based on no reverse power flow across SCADA-operated devices is a reasonable short-term solution to the preservation of operational flexibility. Therefore, the WG recommends that the IOUs calculate the ICA values both with and without this constraint in the first system-wide rollout of the ICA without waiting for further refinement of the criterion. The WG recommends that in the first system-wide rollout of ICA results, two sets of values be published (for reference to sets of ICA values, please see Section 9: Presentation of ICA Values):

1. Set of ICA values as applied in Demo A with operational flexibility limitations on SCADA devices
2. Set of ICA values allowing reverse power flow across the SCADA devices up to the substation low-side busbar and without allowing reverse power flow to the high-side busbar across the substation transformer towards the transmission system

Publishing both values will better indicate the hosting capacity where this factor could be mitigated or determined to be non-constraining through Supplemental Review in the Rule 21 process. It is important to note that this second value differs from the second value tested in Demo A in accordance with ACR requirements.

Considerations for Long-Term Refinement

The WG engaged in discussions regarding means to improve how operational flexibility is addressed within ICA. Many WG members place high priority on development of an improved operational flexibility criterion as a key long-term refinement item. These WG members envision that the WG develop an improved, less heuristic approach based on engineering analysis that evaluates whether a limit on operational flexibility results in any safety or reliability impacts. This new approach may be enabled by an improved understanding of the ICA's ability to evaluate a large number of scenarios and configurations or by a discussion of how the utilities study the operational flexibility impact of an interconnection application that requires such a study. This improved value is expected to replace Screen P (the Safety and Reliability Screen) within the Rule 21 process.

These WG members additionally recognize that one possible solution to this restriction could be that utility may in the future utilize communication means to send commands directly to DER systems or may send communication through third-party aggregators to DER systems as to mitigate the issues related to operational flexibility. However, that capability will only be available after the CPUC develops rules for contractual relationships between utilities and DER system owners through a stakeholder process, or such contracts are found mutually agreeable to counterparties and do not violate existing regulations.

Finally, these WG members feel that further refinement of the operational flexibility criterion will include differentiating between different types of SCADA-operated devices, and recommend that IOUs include this data in their efforts to clean up data in preparation for the first system-wide rollout.

The IOUs would also like to examine whether the operational problem may be solved in future years through the implementation of other potential solutions. Such solutions include the implementation of future DERMS, which would provide high levels of visibility and control and would mitigate the system flexibility limitation. Some WG members are also open to these types of solutions, but would like both to be considered going forward. The WG will determine a more detailed priority list of items in the beginning stages of the long-term refinement process.

Some WG members recommend that the CPUC consider the following questions about the interplay between ICA and operational flexibility:

1. If increased DER adoption has the potential to become a consideration in operational flexibility, how can we quantify the impact of the change in operational flexibility?
2. What kind of change in operational flexibility is appropriate to reach policy goals related to DER adoption?
3. Are there technical and/or policy solutions to expand ICA while still preserving operational flexibility?

The utilities view any reduction of operation flexibility which impacts customer service reliability in favor of increasing ICA as contrary to the goals of DER implementation. Further understanding of these questions may require a separate research initiative or pilot project.

10.3 Circuit models

The IOUs have not historically created computer models of their substations and distribution circuits such that engineering analyses such as power flow and short-circuit analyses can be performed. PG&E models are complete but additional work to enhance the gateway to incorporate requirements set forth by WG recommendations will be needed. SDG&E modeled its distribution system as part of Demo A. SCE modeled 83 of its circuits as part of Demo A, is currently modeling the balance of its system, and expects to complete this process in approximately 8 months. While the IOUs built these models using the best available data, the models and underlying data may require adjustment if power flow models do not converge on a solution during ICA analysis. In the streamlined analysis, only one power flow analysis is performed and model adjustment is only required once, except when circuits change (as discussed below). With the iterative method, additional model adjustments may be required during any of the hundreds or thousands of power flow analyses performed for each circuit, as adding DER in each location has different impacts.

Separately, IOU distribution circuits are constantly changing due to circuit reconfigurations, new utility equipment, new or modified loads, and DER additions. IOU circuit models must be routinely updated and vetted for ICA values to be current and accurate. IOUs have confirmed that they will update their circuit models as part of the implementation work in advance of system-wide ICA implementation. Some stakeholders expressed that ICA cannot be deployed on a system wide basis until each IOU develops a means to adequately incorporate changes in distribution circuits and loads. Tweaks to circuit models in CYME and Synergi required for model convergence are currently lost when new data from GIS and other data sources is incorporated into the power flow model. In addition to details provided in the Final Demo A Reports, the IOUs have provided the following proposals for how models may be updated and remaining work before system-wide implementation:

- PG&E has a gateway tool for incorporating circuit updates into its circuit models on a weekly basis. PG&E also creates yearly planning models from a snapshot of the gateway model which contains specific modifications and planned worked on the circuits. Recommendations from the WG would require additional work to merge the planning models with the gateway models.
- SCE reiterates that it would incorporate significant changes to new circuit models on a monthly basis. SCE is currently developing automated processes to maintain the accuracy of network models and data as changes on the distribution system occur, as part of full system-wide deployment of ICA.
- SDG&E currently automatically updates its models daily, but those are not currently validated for ICA purposes. SDG&E would need to validate those models that have monthly changes for the ICA update.

10.4 Pre-existing conditions

The WG identified a challenge whereby circuit models sometimes display violations of one or more power system criteria before the DER is modeled, resulting in a hosting capacity of zero (i.e., a pre-existing condition on the circuit is responsible for the violation). A targeted DER solution may not impact the existing violation criteria, and in some cases, could even improve the existing violation criteria. However, it may be difficult to automatically determine whether adding a DER solution worsens a violation criteria or creates an entirely new violation.

To address this condition, the WG recommends that (1) ICA should be limited by pre-existing conditions when adding DER degrades the pre-existing condition; and (2) that ICA should not be limited by a pre-existing condition when adding DER improves the pre-existing condition. For example, in a situation when low voltage exists in an area, adding generation may improve the low voltage condition but adding load may degrade the pre-existing conditions. In this example, the ICA for new generation would not be limited by the pre-existing condition but the ICA for new load (i.e. electric vehicles) would be limited by the pre-existing condition. It should be noted that in some cases, such as substations with load tap changer (LTC) control, adding generation to a low voltage pre-existing condition may further degrade the low voltage condition rather than improve the low voltage condition. These refinements should be included within the first system-wide rollout of ICA.

To implement this recommendation, the IOUs will need to create automated processes as part of the ICA implementation plan to efficiently evaluate the feeders and substations for pre-existing conditions. These processes would need to determine if any pre-existing conditions exist and to determine if adding DER would improve or degrade the detected pre-existing condition and take the necessary action to determine when ICA can be allowed or when ICA must be limited by the pre-existing condition. The IOUs expect that this process will require significant IT resources to automate and/or significant engineering resources to properly consider evaluate pre-existing conditions on a regular basis. These additional costs were included in the utilities' costs estimates.

11 Short-term WG Activities as Outlined by ACR

The ACR outlines seven discrete activities for WG consultation related to Demo A (ACR Section 3.1). The IOUs consulted with the WG on each of these topics in 2016. A summary of those topics, discussions, and recommendations are included below.

11.1 ACR Section 3.1.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

11.1.1 With regards to DER bundles or portfolios responding to CAISO dispatch

For Demo A, the IOUs generated technology-ICA results in consultation with the ICA WG, given that assumed DER operational profiles do not accurately represent variations due to locational and technology specifications. It was also determined that it would be difficult to accurately define the ICA in a meaningful way for hypothetical DER bundles, without knowing the specific operational profiles and combination of the DER in the bundle.

The WG agrees with use of a technology-agnostic approach to determine ICA values in the full system-wide rollout and not be required to determine ICA values based on technology specific DER bundles or portfolios, or through assumptions about CAISO dispatch.

11.1.2 With regards to smart inverters

The WG envisions that smart inverters can influence the ICA in that smart inverters may, in certain conditions, support greater hosting capacity.

Within Demo A, the IOUs did not recommend methods for evaluation of hosting capacity with regard to smart inverters. However, the IOUs did conduct analysis to start understanding the impact of smart inverters on ICA, and recommended to the WG that integration of smart inverters be considered as a future enhancement building upon Demo A results, at the August ICA WG meeting. The WG accepted this in the development of ICA as a reasonable first step. IOUs limited their Demo A study to the Smart Volt/VAR function which, when used properly, may have the ability to reduce steady state voltage rise. These capabilities were tested on a limited basis by each utility using either the streamlined method or the iterative method.

The utilities performed ICA calculations applying a limited set of smart inverter capabilities on one distribution feeder to determine how smart inverters may be able increase the integration capacity. The capabilities tested were a static volt/VAR curve (SCE) and fixed power factor (PG&E and SDG&E). The studies indicated that smart inverter may be able to support higher levels of ICA in certain system conditions.

The WG recognizes that universal reactive power priority cannot be incorporated into the ICA until standards are improved and compliant inverters are widespread. Additional methodology development and software enhancements are required as the WG determines how smart inverters may be incorporated in the near term. Currently, smart inverter functions are being finalized, while understanding how to study the functions within ICA requires additional research and development – while CYME and Synergi already contain the ability to include some advanced inverter functionality, but the WG must agree on assumptions of how smart inverters will operate before the software vendors incorporate that capability into the ICA modules.

The ICA WG agrees that smart inverter functionality be included in ICA calculations when the functional methodology has been agreed and developed and tools are capable of implementing smart inverter technology in automated and efficient manner. The WG will do this as part of long term enhancement to ICA, and if methodologies and tool enhancements are developed in time for inclusion to the first system wide roll out, then those functions of smart inverters will be added to the first system wide roll out; otherwise, the IOUs will include the agreed upon-smart inverter functions in subsequent iterations of the ICA as methodologies are developed and tools are enhanced.

The WG also identified additional studies that would inform the understanding of the impacts of smart inverters on hosting capacity, including static volt/VAR and fixed power factor functions, as inverter standards are finalized through the IEEE process and as smart inverters begin to proliferate in the market. While important, is also acknowledged that significant resources may be required to determine an appropriate methodology for smart inverter inclusion in ICA, given that complex studies will require significant engineering resource which will need to be prioritized based other ICA study requirements (such as Single phase, transmission impacts, etc.). These studies should consider two overarching questions: 1) at what point can smart inverters be expected to have an impact on increasing hosting capacity? 2) once smart inverters are implemented as common practice, how much will they impact hosting capacity? The WG identified the following areas of additional evaluation for consideration, pending prioritization of all long-term refinement items and resource availability

- How the various smart inverter functions and applicable function ranges affect ICA values
    1. Volt/Var
    2. Fixed Power Factor
    3. Volt/Watt
    4. Function prioritization (what Brad is interested in ->)
    5. Phase II communication implications
    6. Phase III advanced functions implications
    7. Future IEEE 1547 oversizing implications, if approved
- Determine the range of settings and curves that can provide maximum ICA without negatively affecting the distribution system
- Determine the effects of the application of smart inverter functions to the distribution system reactive capacity and system efficiency

Finally, some stakeholders would like to understand how ICA may consider dynamic inverter functions, which may include settings to be changed by season, TOU period, and weekday vs. weekend, and in response to price signals and temperature forecasts. These stakeholders would like to evaluate this capability in coordination with a need for Rule 21 to include verification of operating profiles before systems can be approved based on dynamic functions. However, it is noted that further research of dynamic inverter functions is not within the scope of the ICA WG, and therefore not a research study appropriate for the IOUs to take on.

11.2 ACR Section 3.1.c: Recommend a format for the ICA maps and downloadable data to be consistent and readable by all California stakeholders across the utilities service territories with similar data and visual aspects (Color coding, mapping tools, etc.).

The WG discussed ICA map formats in the July WG meeting. The ACR specifies requirements for how ICA results shall be available via utility maps. To reach common fundamental principles guiding the ICA map formats, the joint IOUs presented a proposal for displaying ICA results, including the structure of mapping layers (substations, circuits, line segments all visible) and which information will be viewable in map format and which will be included in the downloadable data set.

The WG agrees and recommends that the IOUs should continue to standardize to a common mapping structure and mapping functionality while using what was developed for Demo A for first system rollout. Additional proposed modifications are discussed below; some have WG consensus, while others may require further discussion. The IOUs recommend that additional enhancements to maps for the full system roll-out may be added by the utilities as allowed by their tools and respective limitations.

As a long-term refinement, and as discussed earlier in Section 9: Presentation of ICA Values, the WG would like to consider how the map may provide verification that available capacity has not been absorbed by another interconnection application submitted since publication of the ICA value. This factor will be reduced as utilities get closer to real-time ICA updates. Much of the coordination work will need to be done within the context of the Rule 21 proceeding.

11.2.1 ICA Maps

The WG agrees that the following attributes should be available across all three IOU maps: 1) circuit; 2) section ID; 3) voltage (kV); 4) substation; 5) system[15]; 6) customer breakdown percentage (agriculture, commercial, industrial, residential, other); 7) existing generation (MW); 8) queued generation (MW); 9) total generation (MW); 10) ICA with uniform generation (MW); 11) ICA with uniform load (MW); 12) integration capacity of a generic PV system (MW).

The WG will develop assumptions for a standard PV generating profile that is sufficiently conservative to be relied upon for interconnection approval, as a long-term refinement item. Within the current value, it is assumed that a solar system produces its maximum rated power every hour of the year and is consequently treated as uniform generation within the ICA. As hosting capacity will be measured on an hourly and seasonal basis, the hourly and seasonal profiles of DERs should be considered.

The WG identifies incorporation of single phase line sections as another high priority item for long-term refinements beginning Q1 2017, and discussed the inclusion of identifying the location of single phase line sections within the first system-wide rollout of ICA to support the interconnection use case. The WG agrees that the IOU online maps should display all single phase line sections with a unique color in the first system-wide rollout. Until the ICA WG develops a methodology for inclusion of single phase line

[15] System data was not required under Demo A. SCE's RAM map includes system data. PG&E's and SDG&E's maps do not currently include system data.

sections, the reflected ICA value will not be of the single phase line section, but rather indicate their location and point of connection to a three phase feeder. In addition, it is recommended that IOUs continue to further develop their gateway and circuit modeling with the understanding that single phase line sections will eventually be incorporated.

The IOUs agree on the potential value of identifying single phase line sections on a map separate from determining their actual ICA value, but additionally note that determining accurate single phase ICA would require significant investment in the development of comprehensive single phase network models. This is because the IOUs do not currently have a complete source of single phase information for their network models. The IOUs agree that the WG should continue to explore the applicability of single phase ICA values taking into account the cost to develop the single phase ICA values against the efficiencies gained from ICA values in the interconnection use case.

No cost estimates have been developed on this topic at this time.

11.2.2 Downloadable data sets

All IOUs make the following information available via downloadable data set from their Demo A projects: 1) Demo A final report; 2) ICA Translator; 3) load profiles; 4) customer type breakdown; 5) detailed ICA results by circuit.

The WG envisions that there may be some differences between the interconnection use case and planning use case with regards to map and dataset needs, and so far, have only discussed data within the context of the interconnection use case. Given the amount of data produced in calculating ICA results and size of data files, the IOUs recommend limiting future downloadable data to only actionable data based on use cases. Additional downloadable data should be discussed with WG to determine which data should be downloadable for system wide implementation and the associated requirements and costs.

The WG has already identified issues related to data access as an important long-term refinement item to be addressed in the next six months, some of which are detailed in the Interim ICA Long-Term Refinement Report filed December 2016. Some WG stakeholders place a high value on providing data in machine readable formats. IOUs express that data security issues may need to be clarified and vetted, and recommend that discussion on details of how this functionality may be implemented should be deferred to future enhancements within long-term refinement discussions.

11.3 ACR Section 3.1.d: Evaluate and recommend new methods that may improve the calculation of ICA values using computational efficiency method to calculate and update ICA values across all circuits in each utility's service territory

The IOUs presented three proposed methods to improve ICA computational efficiency at the September and October WG meetings, with the purpose of reducing the number of data points needed to calculate in ICA without reducing the quality of results. These methods focus on 1) hourly reduction and mapping, 2) node filtering, and 3) criteria bounding. Each IOU employed different levels of computational efficiency methods in their Demo projects (see the Final Reports for a full discussion). The WG is in consensus with regards to the methodology underlying these computational efficiency refinements and agrees that the methods for node reduction and limitation category reduction are appropriate for use within the IOUs' first system-wide rollout (with differing opinions on whether hourly load profile reduction should be used), though as computing power and other factors change, this may need to be reevaluated to seek the most precise ICA over time and that modifications, adjustments, or additions may be needed for future ICA iterations.

i. **Hourly load profile reduction methods analyze fewer loading conditions**. For example, an ICA using a 576 hourly profile (which uses minimum and maximum load days for every month, for 12 months – 24 x 2 x 12) may be efficiently reconstructed by reducing the number of hours analyzed with similar loading conditions.
    a. The WG has different recommendations on whether this method should be used. The IOUs tested the use of load profile reduction within their Demo A projects. The IOUs presented to the WG on whether ICA can be run using a reduced profile while maintaining the ability to represent a 576 hourly profile. Full discussion of separate IOU viewpoints on whether and how this method should be used can be found in separate IOU Final Demo A reports.
    b. After reviewing Demo A Final Reports, stakeholders of the WG recommend the continued use of a 576 profile, as was tested under Demo A as representative hours of the entire year.

ii. **Node filtering methods** improve efficiency by limiting the number of nodes analyzed – when nodes are within close proximity to each other with no customer loads in between, or nodes exists only for simulation purposes, those nodes have the same level of ICA due to similar levels of impedance and loading conditions.
    a. The WG is in consensus with the use of node filtering methods in the first system-wide rollout of ICA.

iii. **Reduction of limitation categories for feeders with a high short circuit duty.** For those specific feeders, the voltage fluctuation screens and protection limitation screens do not need to be evaluated, as they will not affect the final ICA value.
    a. The WG is in consensus with the use of reducing limitation categories in the first system-wide rollout of ICA.

11.4 ACR Section 3.1.e: Evaluate ORA's recommendation to require establishment of reference circuits and reference use cases for comparative analyses of Demo Project A results.

The CPUC directed the IOUs to work towards additional consistency between IOUs' methodology and assumptions, for both the iterative and streamlined approach. To ensure a common approach between IOUs, the Commission asked the IOUs to compare methodologies against reference circuits, for discussion and approval by the WG.

The IOUs used the IEEE 123 test feeder as the reference circuit for comparative analysis as it employs a public data set of power flow results. The IOUs first compared power flow results between the power system analysis tools (PG&E and SCE employ CYME, and SDG&E employs Synergi), and then within each IOU for the Demo A test feeder.

The IOU Demo A reports include a joint report component. Within that joint report, the IOUs conclude that overall, the ICA results do not have significant variation across the IOUs for both the iterative and streamlined methodologies, with the slight variations attributed to how power flow models are treated between CYME and Synergi.

Another comparative assessment in IOUs Demo A projects evaluated the difference between iterative and streamlined methods. This assessment was used to determine which of the two methods would be most appropriate for the use cases and for implementation of first system wide roll out. Full exploration of these differences are detailed in the separate IOU Final Demo A Reports.

The WG recommends exploration of the utilization of more representative circuits from California feeders, and will prioritize this future testing alignment against other competing resources and cost considerations through full WG discussions, within ICA long-term refinement. This recommendation should be part of the long-term future enhancements to ICA.

The Office of Ratepayer Advocates (ORA) included 12 metrics of success for evaluating ICA. ORA provided the WG with a table of these criteria on January 10, 2017, with a brief description of whether the IOUs have met the criteria. IOUs have additionally detailed individual responses to ORA's 12 metrics in their Final Demo A reports. The most recent version of the table is provided below:

Table 3: ORA 12 Criteria or Metrics of Success

ORA Criteria	SCE	SDG&E	PG&E	Comments from ORA
1. Accurate and meaningful results				
A. Meaningful scenarios				Need to verify if reverse flow at substation busbar is correctly modeled.
B. Reasonable technology assumptions				Need plan to incorporate smart inverter data.
C. Accurate inputs (i.e. load and DER profiles)				Track 3.

D. Reasonable tests (i.e. voltage flicker)				No concerns/alternatives from working group.
E. Reasonable test criteria (i.e. 3% flicker allowed)				No concerns/alternatives from working group.
F. Tests and analysis performed consistently using proven tools, or vetted methodology				Tools being developed as part of Demo A and LT refinements.
2. Transparent methodology				IOUs have been open to information requests.
3. Uniform process that is consistently applied	LT Item	LT Item	LT Item	QA/QC of custom Python scripts TBD.
4. Complete coverage of service territory				Not required at this point.
5. Useful formats for results				PG&E is continuing to work on making the map more functional. This includes upgrading the server to improve map loading speeds, which will enable PG&E to adopt tools such as an ESRI tool to enhance usability. All utilities should include the "system" attribute in the full circuit deployment. SDG&E has not provided access to results.[16]
6. Consistent with industry, state, and federal standards				No concerns/alternatives from working group.
7. Accommodates portfolios of DER on one feeder				Uniform Gen map, plus DER translator. Need to ensure DER translator will work independent of the map showing uniform generation or PV profile.
8. Reasonable resolution				
–Spatial				Optimal (lower) resolution TBD; nodal reduction proposal.
–Temporal				Optimal (lower) resolution TBD; 576 vs. 24 hours.
9. Easy to update based on improved and approved changes in methodology				QA/QC of custom Python scripts TBD.

[16] SDG&E provided access to online results on 3/10/17. SDG&E realizes that this does not provide sufficient time for stakeholders to review the results prior to submission of the Final ICA WG Report. SD&E also should not have to provide a "system" field. SDG&E's transmission system is a single interconnected system, and therefore believes the requirement to provide a "system" field for each substation and/or circuit should not apply.

10. Easy to update based on changes in inputs (loads, DER portfolio, DER penetration, circuit changes, assumptions, etc.)				Tweaks to circuit models in CYME/Synergi required for convergence are currently lost when new data from GIS and other data sources is incorporated into power flow circuit model.
11. Consistent methodologies across large IOUs				
12. Methodology accommodates variations in local distribution system				
Legend				
Criteria met, OK to proceed				
Must be resolved before full scale deployment, but ORA believes they will be resolved by ongoing WG activity.				
Important issues have not been resolved to ORA's satisfaction, and it is not certain whether they will be before full scale deployment. Delay full scale deployment until resolved.				

Explanation Text Provided From ORA:

The legend describes how close to the IOUs are to meeting the Criteria.

- Green means that the IOUs have met the criteria, so it is ok to proceed with full scale circuit modeling.
- Yellow means that these are areas that have been identified as criteria that must be resolved before full scale deployment, but current WG activity will resolve them.
- Red means that these are issues that the utilities have not been adequately resolved, and it is not certain whether they will be resolved before full scale deployment. Full scale deployment of the ICA should be delayed until these criteria are met.

The WG understands that not all of the requirements can or need to be met in order to begin performing the full-scale circuit modeling. However, the WG expects the IOUs to meet these criteria as the ICA is refined over time.

In regards to Criteria 10, SCE agrees that maintaining accurate circuit models and related data is of extreme importance for the development of ICA values and one that the WG should continue to monitor. SCE is currently developing automated and engineering in the loop processes to maintain the accuracy of network models and data as changes on the distribution system occur. While SCE does not object to the color red for criteria 10, SCE does not agree that it cannot commence with the full-scale system-wide circuit modeling, as SCE will create the necessary steps to maintain accuracy of the network models as part of its deployment. Preventing SCE from commencing of full scale-wide deployment of circuit models will delay the implementation of ICA system wide as required the WG members which will ultimately will delay future modifications to Rule 21 to allow timely interconnection.

11.5 ACR Section 3.1.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

In reviewing Final Demo A Reports, WG stakeholders requested further clarification on the use of advanced metering infrastructure within ICA methodology. This application is detailed further by the utilities:

SCE and PG&E aggregated smart meter measurements to their corresponding distribution transformers. That is, the loading of a distribution transformer for a certain hour is characterized by

$$Transformer\_loading=\sum_{i=0}^{n} Customer_i$$

where $Customer_i$ represents a customer served by the transformer and n is the number of customers served by the transformer. By performing this analysis for each hour, load shapes and patterns are generated for each transformer. These localized shapes in combination with the circuit level loading profile were utilized to allocate the feeder level forecasted loading down to the service transformer level or individual customer level. This allowed SCE to more accurately geographically allocate feeder level forecasted loading values down to specific regions on the circuit.

SDG&E brings AMI data at the time of the peak for each customer to establish the demand. Then SDG&E leverage its AMI data to develop different customer classes load profiles. Each customer class has its profile and is created per substation bus. The profile curve adding all the customers consumption on each customer class by hour for that specific class and bus. LoadSeer creates monthly profiles curves per circuit for peak and minimum day (48 points per month) using SCADA data at the breakers. These curves get imported into Synergi and the load gets allocated on the feeder using the combination of Customer class's curves at the transformer level and Feeder profile curves at the breaker level.

It is recommended that the IOUs continue to utilize customer level load data as used in Demos A for first system wide roll out, and the WG would like to further explore reasons for divergence, as well as trade-offs between methods, as part of long-term refinement.

11.6 ACR Section3.1.g: Establish definite timelines for future achievement of ICA milestones, including frequency and process of ICA updates

Please refer to *Section 6: Schedule and Timelines* for discussion on ACR Section 3.1.g.

12 Additional Cost Recovery

The WG acknowledges that continued deliberation with regards to cost impacts and cost recovery will likely occur in a separate forum. It is also acknowledged that the IOUs can continue to engage in some work related to the full system roll-out, such as data clean-up efforts, independent of a CPUC Proposed Decision.

Depending upon the implementation requirements adopted by the Commission, additional cost recovery may be necessary. The WG therefore recommends that CPUC adopt a process to facilitate IOU requests for additional funding to support ICA implementation.

13 Recommendation Summary Table for First System-Wide Implementation of ICA

Table 4: Summary of Recommendations for Interconnection Use Case and First System-Wide Roll Out
For full detail, please reference specific report sections.

Component	Consensus?	Recommendations	WG activity on Long-Term Refinement (6 months)	Refer to Report Section
1. Methodology	Non-Consensus	SCE, SDG&E, WG stakeholders: iterative method PG&E: "blended" approach (see Final Demo A Report)	See other sections	Section 5: Methodology
2. Update frequency	Non-Consensus	Non-IOU stakeholders: weekly SCE and SDG&E: no more than monthly PG&E: dictate updates by conditions, not time frame		Section 7: Review of Cost Estimates Section 8: Frequency of Updates
3. Hourly profile	Non-Consensus	PG&E, SCE, SDG&E: see Final Demo A Reports Non-IOU stakeholders: 576 hour profile		Section 7: Review of Cost Estimates Section 11.3: ACR Section 3.1.d
4. Circuit models	Consensus	Incorporate changes to circuit models in advance of full system implementation is needed.		Section 10.3: Circuit Models Section 11.4: ACR Section 3.1.e
5. Pre-existing conditions	Consensus	ICA should be limited by pre-existing conditions when additional DER degrades the pre-existing condition.		Section 10.4: Pre-existing conditions

		ICA should not be limited by a pre-existing condition when adding DER improves the pre-existing condition.		
6. Voltage regulating devices	The WG is in consensus with allowing devices to "float" within power flow models. There is non-consensus with regards to process and implementation. Based on Demo A implementation: **SCE & PG&E** - Locked **SDG&E** – Float. SCE & PG&E use CYME software. SDG&E uses Synergi software.	PG&E, SCE, and SDG&E recommend operations as applied in Demo A, and will continue to work with software vendors to encourage the development of an additional "unlock" function. Currently, CYME software does not support this option. Requiring the inclusion of this function may delay the 12 month implementation timeline proposed. Non-IOU stakeholders encourage IOUs to work with software vendors to include this feature within the first rollout, if feasible.		Section 10.2.1: Power quality/ voltage criteria
7. Operational flexibility	Consensus	Publish two ICA values: 1) no reverse flow across SCADA operated devices, 2) reverse flow up to substation low voltage busbar with no export to the high side busbar towards the transmission system	Continued discussion on improving operational flexibility criterion, using non-heuristic values	Section 10.2.2: Safety and reliability
8. Smart inverters	Consensus on recommendation, non-consensus on process and timing	WG agreement to include smart inverter functionality within ICA. Given that assumptions and functionalities need to be developed, there are two separate recommendations on process and timing: IOUs recommend that smart inverters not be included in first system roll out until further methodologies and modification to tools are developed and implemented. IOUs will begin work with software vendors to determine best means of incorporating smart inverter data when methodology is developed. Other stakeholders recommend that IOUs endeavor to work with software vendors to include, if possible, in the first-system rollout.	Develop assumptions for smart inverter operating behavior Consider additional studies	Section 11.1: ACR Section 3.1.b
9. Maps and Published Values	Consensus	Set of ICA data: Publish uniform generation ICA, uniform load ICA, and a PV ICA value based on common PV shape	Develop standard PV generation	Section 9: Presentation of ICA Values

		2 sets of ICA data should be published, addressing two different operational flexibility constraints. In total, 6 values are published.	profile Continued discussion on downloadable data sets	Section 11.2: ACR Section 3.1.c
10. Computational efficiency	Consensus approval for use of methodologies in Demo A	IOUs may utilize the methods of computational efficiency to reduce nodes and reduce limitation categories, as tested in Demo A in the first system roll-out. There is non-consensus with regards to whether hourly profile reductions should be used to reduce the 576 profile as tested under Demo A.		Section 11.3: ACR Section 3.1.d
11. ORA success criteria and reference circuits	See Section 11.4	See Section 11.4	Consider additional reference circuit	Section 11.4: ACR Section 3.1.e
12. Smart meters	Consensus	Utilize customer level load data as used in Demos	Explore further reasons for divergence and comparison between methodology	Section 11.5: ACR Section 3.1.f
13. Timelines	Non-consensus	PG&E, SCE and SDG&E: 12 months from PUC Final Decision CALSEIA: 12 months from filing of ICA WG Final Report		Section 6: Schedule and Timelines

14 Next Steps for the ICA WG

The WG looks forward to continuing improvement and development of additional methodological components for the ICA, and has developed an additional list of items to begin working on within the next long-term refinement phase of the ICA WG after its review of Demo A Final Reports, given that some recommendations are potentially considered for the first system-wide rollout of ICA if necessary methodology and studies are developed. This table is meant to complement those topics already identified in the Interim ICA Long-Term Refinement Report[17] (e.g., data access, single phase line sections, etc.). This table does not re-iterate those topics.

The WG aims to create a proposed working schedule as a priority item once work on long-term refinement items begin.

Table 5: Additional topics for Long-Term ICA Refinement

Topic	Section
Use cases: further development of planning use case, with CPUC guidance and in accordance with further development of Track 3 of DRP proceeding	Section 4: Use cases
Development of standard PV generation profile for published ICA value	Section 9: Presentation of ICA values
Development of operational assumptions for voltage regulating devices	Section 10.3: Voltage regulation
Continued discussion of how to improve the operational flexibility criteria	Section 10.4: Safety and reliability
Integration of smart inverter technology, potential additional studies	Section 11.1.2: Smart inverters
Additional reference circuit	Section 11.4: Reference circuits
Further review of underlying assumptions (e.g., weather) with consideration of parallel Track 3 activities	Section 10.1: Modeling and extracting power system data
Smart meters: additional discussion comparing methodology	Section 11.5: smart meters

[17] http://drpwg.org/wp-content/uploads/2016/07/R.14-08-013-ICA-Status-Report.pdf

15 Appendix

15.1 Acronyms

ACR: Assigned Commissioner's Ruling
CPUC or Commission: California Public Utilities Commission
DER: Distributed Energy Resources
DRP: Distribution Resources Plan
ICA: Integration Capacity Analysis
IOU: Investor Owned Utilities
IRP: Integrated Resources Proceeding
LNBA: Locational Net Benefits Analysis
PG&E: Pacific Gas & Electric
SCADA: Supervisory control and data acquisition
SCE: Southern California Edison
SDG&E: San Diego Gas and Electric
WG: Working Group

15.2 Working Group Meetings and Topics

Meeting Date	**Topic(s)**
May 12 – 1:00pm-3:00pm Webinar	Opening meeting
May 18 – 10:30am-12:00pm Webinar	Seeking input regarding 1) use of power flow analysis and 2) level of granularity
June 1- 9:00am-3:00pm In person	First discussion of demonstration implementation plan before June 16th submission
June 9 – 9:00am-3:30pm In person	Second discussion of demonstration implementation plan before June 16th submission
July 5 – 2:00pm-4:00pm Conference call	Call to discuss submission of demonstration implementation plan
July 25 – 9:00am-3:30 pm In person	Discussion of submitted stakeholder comments on demonstration implementation plans Use cases 3.1.c/3.2.c – data and maps 3.1.b – portfolio analysis
August 31 – 9:00am – 4:15pm In person	Use cases 3.1.b – smart inverters 3.1.f – smart meter/customer load data Data access
September 30 – 9:00am-4:00pm In person	3.1.e – comparative analysis 3.1.b.i – portfolio analysis 3.1.d – computational efficiency Data access
October 17 – 9:00 am-4:00pm In person	Demo A update 3.1.d – computational efficiency

	3.1.f – smart inverters 3.1.e – comparative analysis 3.1.b.i – DER portfolios 3.2.a-g – long-term scoping discussion
November 18 – 9:00am-4:00pm In person	Review of Working Group short term final report outline Long-term scoping discussion of 3.2.a-g plus other topics Data
December 13 – webinar	Review of Working Group interim long-term report topics
January 6 – 9:00am – 4:00pm In person	Review of Final IOU Demo A Reports
January 17 – 9:00am – 4:00pm In person	Review of Final IOU Demo A Reports
January 20 – 9:00am – 4:00pm In person	ICA Recommendations
February 2 – 2:00pm-4:00pm Webinar	ICA Recommendations and development of report
February 14- 9:00am – 1:00pm Webinar	ICA Recommendations and development of report
February 27 – 11:30am – 1:00pm Webinar	Review of IOU cost estimates
March 9 – 9am -1pm	Final ICA discussion before WG report

15.3 Working Group Participants

The following stakeholder groups attended at least one meeting or webinar of the ICA WG:

- ABB Group
- Advanced Microgrid Solutions
- Alcantar & Kahl
- AMS
- Artwel Electric
- Bloom Energy
- CAISO
- California Energy Storage Alliance
- California Energy Commission
- CPUC Office of Ratepayer Advocates
- California Solar Energy Industries Association
- City of Burbank
- Clean Coalition
- Community Choice Partners
- Community Environmental Council
- Comverge
- DNV GL
- ECCO International Inc.
- Energy and Environmental Economics
- Electric Power Research Institute
- Energy Foundation
- Environmental Defense Fund
- Gratisys Consulting
- Greenlining Institute
- Helman Analytics
- ICF International
- Independent Energy Producers Association
- Independent advocates
- Independent consultants
- Integral Analytics
- Interstate Renewable Energy Council
- Kevala Analytics
- Lawrence Berkeley National Laboratory
- Lawrence Livermore National Laboratory
- Natural Resources Defense Council
- Northern California Power Agency
- NextEra Energy

- New Energy Advisors
- Nexant
- Open Access Technology International
- Pacific Gas & Electric
- PSE Healthy Energy
- Quanta Technology
- Sacramento Municipal Utilities District
- San Diego Gas and Electric
- Siemens
- Smart Electric Power Alliance
- SoCal REN
- Solar Energy Industries Association
- SolarCity
- Solar Retina
- Southern California Edison
- Stem Inc.
- Strategy Integration
- Sunpower
- Sunrun
- The Utility Reform Network
- UC Berkeley
- Vote Solar

15.4 WG Materials

All ICA WG materials, including meeting materials (participant lists, agendas, presentation materials, meeting summaries if available, and webinar recordings if available), and WG member comments and responses to materials may be found at the DRP WG website: http://www.drpwg.org.

IOU Final Demo A Reports may be found at the following links:

- PG&E: http://drpwg.org/wp-content/uploads/2016/07/R1408013-PGE-Demo-Projects-A-B-Final-Reports.pdf
- SCE: http://drpwg.org/wp-content/uploads/2016/07/R1408013-SCE-Demo-Projects-A-B-Final-Reports.pdf
- SDG&E: http://drpwg.org/wp-content/uploads/2016/07/R.14-08-013-DRP-Demos-A-B-Reports-SDGE.pdf

(End of Appendix D)

APPENDIX E

FILED
3-08-17
04:59 PM

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 (U 901-E) 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

LOCATIONAL NET BENEFIT ANALYSIS WORKING GROUP FINAL REPORT

ANNA J. VALDBERG
MATTHEW W. DWYER

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-6521
Facsimile: (626) 302-1935
E-mail: Matthew.Dwyer@sce.com

Dated: March 8, 2017

Pursuant to the May 2, 2016 *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B* and the August 23, 2016 *Assigned Commissioner's Ruling Granting the Joint Motion of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas & Electric Company to Modify Specific Portions of the Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*,[1] and Administrative Law Judge Mason's *Email Ruling Granting Southern California Edison Company's Rule 11.6 Request For Extension*, Southern California Edison Company (U 338-E) respectfully submits the Locational Net Benefit Analysis Working Group's Final Report.

ANNA J. VALDBERG
MATTHEW W. DWYER

/s/ Matthew W. Dwyer
By: Matthew W. Dwyer
Senior Attorney for
SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-6521
Facsimile: (626) 302-1935
E-mail: Matthew.Dwyer@sce.com

Dated: March 8, 2017

[1] R.14-08-013, *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; And (2) Authorizing Demonstration Projects A And B*, May 2, 2016, Appendix A at p. 38; R.14-08-013, *Assigned Commissioner's Ruling Granting the Joint Motion of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas & Electric Company to Modify Specific Portions of the Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B Southern California Edison Company*, August 23, 2016, Appendix A at p. 38.

Appendix

LNBA Working Group Final Report

Table of Contents

1 Executive Summary

Assembly Bill 327 (Perea 2013) established Section 769 of the California Public Utilities Code, which requires the Investor Owned Utilities (IOUs) to prepare Distribution Resource Plans (DRPs) that identify optimal locations for the deployment of distributed energy resources. In August 2014, the Commission began implementation of this requirement through Rulemaking (R.) 14-08-013, the Distribution Resource Planning (DRP) proceeding. A Ruling from the Assigned Commissioner in February 2015 introduced the concept of a unified locational net benefits methodology consistent across all three IOUs that is based on the Commission approved E3 Cost-effectiveness Calculator, but enhanced to explicitly include location-specific values and to include certain additional avoided cost components. A Ruling from the Assigned Commissioner issued on May 2, 2016 (May 2 ACR) adopted Locational Net Benefits Analysis (LNBA) methodology for use in DRP's Demonstration Project "B" (Demo B), and authorized the Utilities to pursue Demonstration Project B to perform LNBA methodology for one Distribution Planning Area (DPA) in each Utility's service area.

In addition to approving the LNBA methodology and approving the Utilities' Demonstration Project B, the May 2 ACR also established a LNBA Working Group (WG) to monitor and provide consultation to the IOUs on the execution of Demo B and further refinements to LNBA methods. The May 2 ACR identified four main purposes of the WG, namely, (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, and (4) coordinate with the IDER solicitation framework working group where objectives may overlap (e.g., the definition and description of grid deficiencies vs. distributed energy resource (DER) performance requirements and contractual terms needed to ensure DERs meet the identified grid deficiencies).

Pacific Gas & Electric, Southern California Edison, and San Diego Gas and Electric submitted their final Demo B reports at the end of December 2016. These reports summarize demo results, lessons learned, and recommendations on methodology calculation and next steps regarding implementation of LNBA.

The May 2 ACR had clarified that the WG's activities were organized by (i) short-term work related to the Demo 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 Demo B. Short term work should be addressed by the time of the submittal of the final Demo B report. The scope of WG's activities related to Demo B was defined in the ACR as, (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.), and (b) consult to the IOUs on further definition of grid service, as described in the May 2 ACR, and in coordination with IDER proceeding. The WG additionally ended up discussing a variety of other long-term refinement topics not specifically outlined in the ACR. These discussions fall under the ACR-defined WG purpose of "continuing to improve and refine the LNBA methodology" and will be further discussed during the WG's long-term refinement period.

The purpose of the LNBA WG Final Report is to summarize recommendations made by the WG in order to allow the Commission to a make an informed decision regarding next steps, provide support to the CPUC to make a Proposed Decision on Demo B, assist the Commission in developing an implementation plan for further development of LNBA, and outline refinements the WG believes need to be addressed before adoption and full system-wide rollout of an LNBA methodology and tool. These include identification of methodological refinements needed to enhance the LNBA in the future, potentially to address future use of LNBA.

After reviewing the IOU Demo B final reports, the WG developed the following overall recommendations:

- PG&E and SCE's Demo B projects meet compliance with the ACR, while SDG&E has yet to provide Demo B online maps;
- The current LNBA methodology is not yet ready for a system-wide rollout. LNBA methodology, as developed through Demo B, may be used on a provisional basis in the DRP and IDER pilots in two defined use cases (i.e., for information purposes, and as a tool to support identification of project deferral);
- LNBA methodology requires additional refinements before it can be implemented system-wide. These additional refinements fall under multiple categories, and the WG will endeavor to address many during its long-term refinement phase through additional analysis. The WG has not yet reached consensus on which refinements may be needed (and at what level of granularity), but have discussed recommendations in the following categories:
    - Replacing certain system values with local values
    - Developing a methodology to determine avoided transmission capital costs
    - Improving the presentation of LNBA information via tool and heatmap
    - Accommodating additional complexity in DER solutions
    - Broadening the analytical scope to account for additional distribution benefits and account for uncertainty
- Not all recommendations within the above categories received sufficient discussion during WG meetings, given the number of issues identified for refinement, to determine a clear consensus or non-consensus perspective from WG parties. These issues are summarized within the report's "discussion" section within each short and long term recommendation. Some Parties have provided input on these topics, but they should not be considered consensus/non-consensus, or reflective of a full WG discussion.;
- Disagreement exists whether LNBA may be used for purposes other than a tool to provide public information regarding optimal locations for DER deployment. Some parties believe that prioritization of refinements will vary based on potential future uses, and that Commission's guidance may be necessary to assist the WG in further scoping future uses of LNBA, as identified by the Energy Division in a February 1 memo which was written to "help inform the WG's recommendations in this report of how the LNBA could evolve beyond the Demo B methodology to meet the broader procedural needs for the analysis" [1];
- Most of the focus of the LNBA WG has been on creating a methodology for identifying opportunities to defer investments that are already in utility upgrade plans within a certain time

[1] During the period in which the WG was developing this report, CPUC Staff distributed a Memo to WG members discussing potential future uses of LNBA in other proceedings. The WG did not have sufficient time to discuss the memo within the context of WG meetings, and so while certain recommendations in the report may indirectly relate to various items contained in the Memo, the Report does not directly address or respond to the memo, which is available here: http://drpwg.org/wp-content/uploads/2016/07/CPUC-Memo-on-LNBA-Use-Cases-Feb-1-2017-mm7.docx

horizon. The WG determined additional discussion regarding long-term refinements will help determine whether the distribution deferral framework is the correct foundation for the broader issue of evaluating the overall locational benefits of DERs; and

- Commission guidance is requested to assist in prioritizing issues for WG consideration while acknowledging some topics may require substantive analysis. The LNBA WG expects to continue to work on long-term refinement items. The WG has identified a number of items for methodological refinement, but it has not yet determined how to prioritize its work going forward within the WG's long-term refinement phase.

WG discussions have been facilitated by More than Smart, and the LNBA WG has met at least once per month since May 2016. The WG is expected to maintain this meeting frequency through Q2 2017. Meetings have been in person or via webinar and conference call (see Appendix) and can be found at the WG website at www.drpwg.org.

2 Introduction and Background

Assembly Bill (AB) 327 of 2013 added section 769to the California Public Utilities Code, requiring each California Investor Owned Utility (IOU) to submit a Distribution Resources Plan (DRP) proposal "to identify optimal locations for the deployment of distributed resources…" using an evaluation of "locational benefits and costs of distributed resources located on the distribution system" based on savings distributed energy resources[2] provide to the electric grid or costs to utility customers.

Locational Net Benefit Analysis (LNBA), which evaluates DERs' benefits at specific locations is one of several new analytical methods needed to achieve the future envisioned in the DRP - one where DERs are deployed at optimal locations, times, and quantities so that their benefits to the grid are maximized and utility customer costs are reduced.

In a May 2, 2016 ruling,[3] the PUC directed the IOUs to demonstrate LNBA methodology – in particular, how to quantify DER benefits to the transmission and distribution (T&D) system – at a high level of granularity. This LNBA WG report provides recommendations on LNBA in response to the completion of that demonstration (Demo B) to inform a future Commission Decision on further evolution of LNBA.

In accordance with the May 2, 2016 ACR in the DRP proceeding[4] (R-14-08-013), the LNBA Working Group was established to monitor and provide consultation to the Investor Owned Utilities (IOUs) on the execution of Demonstration Project B and further refinements to LNBA methodology. CPUC Energy Division staff has oversight responsibility of the WG, but it is currently managed by the utilities and interested stakeholders on an interim basis. The utilities jointly engaged More Than Smart to facilitate the WG. The Energy Division may at its discretion assume direct management of the WG or appoint a WG manager[5].

---

[2] Per AB 327, DERs includes distribution-connected energy efficiency, energy storage, distributed generation, demand response, and electric vehicles.
[3] Available here: http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=161474143
[4] A modified ACR was granted on August 23 to modify specific portions of the May 2, 2016 ACR. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M166/K271/166271389.PDF
[5] ACR R-14-08-013 Section 6: "LNBA Working Group"

2.1 LNBA Demonstrations

The May 2 ACR approved an LNBA methodology framework for Demo B, instructed the IOUs to apply the LNBA methodologies to one or more Distribution Planning Area(s) (DPAs), and directed the IOUs to submit a final report and results by the end of 2016.[6] The table below from the May 2 ACR lists the components of the LNBA as defined for Demo B, and, for each, indicates a basic or "primary" LNBA methodology as well as a more complex "secondary" option.[7]

Table 1: Approved LNBA Methodology Requirements Matrix for Demo Project B

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 values with flexibility factor (4)	Use DERAC values 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)

[6] Ibid, at pp. 25-34.
[7] ibid, at pp. A26-A27.

The T&D avoided costs, highlighted in bold font in the ACR table above, are the central focus of Demo B, since they are the LNBA components most sensitive to location.[8] Most non-T&D components of the LNBA in Demo B are borrowed from the existing DER Avoided Cost calculator (DERAC) [9] or are expansions upon the DERAC in the case of flexible and local RA and renewable integration cost. These non-T&D components are sometimes collectively referred to as system-level avoided costs.

Each IOU followed the high-level process below in applying the Commission's guidance in the LNBA demonstration projects:

1. Select one or more DPAs that include "one near-term and one longer-term distribution infrastructure project for possible deferral"[10] and "at least one voltage support/power quality- or reliability/resiliency-related deferral opportunity in addition to one or more capacity-related opportunities;"[11]
2. Identify, for every location in the selected DPA(s), "the full range of electric services that result in avoided costs" including "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;"[12]
3. Prepare, for each location with an identified upgrade, a location-specific service specification, identify capabilities that are required of incremental DERs to provide that service;
4. Compute, for each location, a project deferral avoided cost that could be attributed to incremental DERs that meet the required capabilities and apply the approved LNBA methodology to calculate LNBA results;
5. Execute these steps under two different distribution planning DER growth scenarios: (a) the Utilities' base distribution planning scenario and (b) the Very High scenario as filed in the July 2015 DRPs;
6. Make the results available via a heat map along with the DER growth scenario data on the Integration Capacity Analysis map;
7. Provide access to software and data used in Demo B and coordinate with the LNBA Working Group in monthly meetings and to coordinate with the Integrated Distributed Energy Resources (IDER) proceeding

The IOUs, in consultation with the LNBA WG, adopted the IDER Competitive Solicitation Framework Working Group's (CSFWG's) final consensus list of distribution services that DERs can potentially provide. The IOUs also, with help from a consultant, developed a public LNBA Tool which was used to calculate a total avoided cost for all locations within each DPA, including T&D upgrade deferral avoided cost for locations with a deferrable upgrade (i.e. an upgrade providing one of the services identified by the CSFWG. This LNBA Tool is based on the May 2 ACR's "primary" LNBA methodology framework

---

[8] Note that Table 2 of the ACR[8] does not include DER costs – either the cost to procure or the cost to interconnect – as a LNBA component in Demo B, so the LNBA in Demo B is not a full net benefit analysis.
[9] https://ethree.com/public_projects/cpuc4.php
[10] ibid, at pp. A25.
[11] ibid, at pp. A25.
[12] ibid, at pp. 28.

described above; however, the LNBA Tool is designed to easily incorporate many refinements, including several that are reflected in the secondary analysis.

The IOUs also jointly designed their heat maps that provide a visual depiction of Demo B's LNBA results. Each feeder is color coded to provide indicative LNBA results per the following key:

Table 2: Demo B LNBA Results Heat Map key

$	Indicates only system-level avoided costs and no T&D deferral value
$$	Indicates system-level avoided costs plus 0 to < 100 $/kW deferral value
$$$	Indicates system-level avoided costs plus 100 to < 500 $/kW deferral value
$$$$	Indicates system-level avoided costs plus > 500 $/kW deferral value

Further information, including a downloadable version of each IOUs' Demo B final report and links to the public tool and heat maps are available at More Than Smart's DRP Working Group website.[13]

2.2 LNBA Working Group (WG) Role

The activities of the WG 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.

The short-term work of the WG is defined in the ACR under Section 6.1:

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.*

The WG and IOUs met monthly throughout the Demo B process: major decisions (e.g. adoption of the CSFWG service definitions) were made in consultation with the WG, and WG feedback was incorporated into the design of the LNBA tool and heat maps. In particular, the LNBA WG expressed strong support for using technology-agnostic approaches to evaluating location-specific benefits in Demo B. The methods and tools reflected in this Demo B are therefore designed, to the maximum extent possible, to easily evaluate any DER or combination of DERs. In addition to these specific tasks, the ACR specified long-term work of the WG under Section 6.2: "Activity related to Continuing Refinements to LNBA." This report also summarizes WG discussions to-date with regards to continuing refinements.

[13] Located here: http://drpwg.org/sample-page/drp/

2.3 WG Meetings and Topics Discussed

The WG launched on May 12, 2016, and included a total of 17 meetings over 10 months, with the latest meeting occurring on March 2, 2017. The WG discussed many different topics relating to both the methodologies and final deliverables and results of Demo B as well as long-term refinements to LNBA.

A full summary of meeting dates and topics, as well as a list of parties involved in drafting of this report, may be found in the Appendix. The DRP WG site contains additional documentation of meeting agendas, presentation slides, and participant lists.

2.4 Summary of LNBA WG Recommendations

The WG collectively developed a list of recommendations from multiple organizations at the January 20 WG meeting. These recommendations are categorized as follows:

1. Recommendations regarding uses of LNBA and regulatory process;
2. Recommendations for the LNBA tool and methodology as short-term activities;
3. Recommendations for long term refinements to LNBA methodology.

Overall, the WG has reviewed the Demo B projects and determined their compliance with the ACR. The WG additionally notes that further methodological refinements are needed and have engaged in some of those discussions given the ACR directive for the WG to continue to improve and refine the LNBA methodology. There is further non-consensus on whether the LNBA tool developed under Demo B as developed is sufficient for the two proposed use cases proposed at the beginning of the WG process (for reference, see Section 3.2). The WG additionally recognizes that several Commission proceedings and initiatives are looking to the LNBA to develop location-specific avoided cost values for use in various cost-effectiveness analyses, which are primarily identified but not yet fully developed through other CPUC proceedings. Without full clarity on these identified use cases, many WG members do not feel that a conversation on what can and cannot be considered in LNBA methodology is helpful at the time of this report due date with full certainty. However, it is recognized that documenting the discussion topics at hand is helpful as the Commission begins to develop a roadmap on additional methodological refinements needed to facilitate the potential additional use of LNBA within this context.

Table 3: Summary List of LNBA WG recommendations

	Recommendation	Consensus Status	CPUC Policy Guidance Needed
3	*Use Cases, Regulatory Process*		
3.1	*Demo B projects have been completed as required*		
	IOU Demo B Projects Satisfy all CPUC Requirements	Consensus (SCE, PG&E) Non-Consensus (SDG&E)[14]	yes
3.2	*Use Cases*		
	Refine tool to support how LNBA may inform future sourcing options	Non-Consensus	yes
	LNBA methodology and tool may be used on a provisional basis in the IDER and DRP pilots	Consensus	yes
3.3	*Regulatory Process Recommendations*		
	Deferral Framework adoption prior to LNBA system-wide implementation	Consensus	yes
4	*Short term activity: improvements to LNBA that could be adopted in a Q1 2017 decision*		
4.1	*LNBA Tool Functionality: improving the heat map and spreadsheet tool*		
	Tool should include DER profiles and automatically populate output	Consensus	
	Allow multiple locations/multiple projects	Consensus	
	Include VAR profiles for voltage-related upgrades	Consensus	
	Clarify renewable integration cost	Non-Consensus	
4.2	*Bulk System Benefits: Refinement to existing LNBA Values*		
4.2.1	*Replace system values with local values*		
	Develop locational specific avoided cost values for energy and capacity	Consensus	
	Assess variability in location-specific line losses	Consensus	
4.2.2	*Avoided transmission capital and operating expenditures*		
	Form technical subgroup to evaluate potential methodologies for avoided transmission costs	Consensus	Yes
5	*Long-Term Discussion and Potential Refinements on LNBA Methodology*		
5.1	*Consideration of locational benefits beyond those identified in distribution planning process*		
5.1.1	*Account for uncertainty in distribution planning process*		
	Examine methods to reduce uncertainty in planning and utility investment	Non-consensus	
	Incorporate uncertainty metric in LNBA tool for planned deferrable projects	Non-consensus	
	Develop a methodology to incorporate deferrable projects that may occur unexpectedly (i.e., unplanned projects)	Non-consensus	
5.1.2	*Incorporation of additional values into the LNBA*		
	Value locational value of DERs beyond 10 years	Non-consensus	
5.2	*Distribution Benefits: Analytical Scope and Analytical Benefits*		
5.2.1	*Analytical Scope*		
	Including Cost of DER Penetration	Non-Consensus	
	Use Base Growth Scenario Only	Non-consensus	
5.2.2	*Additional Benefits*		
	T&D values to be included in future modifications of LNBA Tool should only reflect values with established quantification	Non-Consensus	Yes
	Asset life extension	Non-Consensus	
	Situational awareness or intelligence	Non-Consensus	

[14] SCE and PGE were in full compliance, SDG&E complied with all aspects of ACR except Section 4.4.2, i.e., SDG&E is still working to make results of their LNBA available via heat map, as a layer with the ICA data in an online ICA map.

	Increased reliability (non-capacity related):	Non-Consensus	
	Evaluating Planned Upgrades Meant to Accommodate Additional DER Growth	Non-Consensus	
	Avoiding Maintenance Projects	Non-Consensus	
	Downsizing Replacement Equipment	Non-Consensus	

Each recommendation is presented in a consistent table format, with information as follows:

Table 4: Recommendations table format

Recommendation	**Short name of recommendation**
Recommendation or Discussion	Recommendation or continued discussion needed with additional understanding of future LNBA use
Consensus?	Consensus or non-consensus
Action type	Three possible Categories: • *CPUC Policy Guidance or CPUC clarification*: WG recommends CPUC clarify policy to govern use/application/implementation of LNBA • *IOUs to implement modification*: WG Recommends IOUs implement modification to the functionality, scope, methodology of the tool. • *WG to analyze further*: WG has identified a potential modification to the LNBA methodology, but further research/analysis is necessary before a final determination can be made of how/if such a modification should be implemented
Description	Simple description of what the recommendation is seeking
Supporting Arguments	Arguments in favor of the recommendation
Opposing Arguments	Arguments against the recommendation

Each section of this report contains (1) an objective section, (2) a summary of discussion, and (3) a recommendations or discussions section. This last section of recommendations and discussions additionally marks current consensus/non-consensus status based on WG discussions up until the time of this report. WG discussions will continue on long-term refinement topics.

3 Discussion and Recommendations: Use Cases, Regulatory Process

Section 3 compiles general comments about the use of LNBA and recommendations for how work on LNBA should progress. In contrast with other categories, these recommendations are not concrete methodological improvements.

3.1 Demo B Projects Have Been Completed as Required

Objective

This section expresses the WG consensus that IOU Demo B implementations are fully compliant with all requirements as set forth in the May 2nd and August 19th Assigned Commissioners Rulings.

Discussion

Parties have many diverse recommendations and expectations for how the LNBA should be developed and refined prior to further implementation. However, parties recognize and agree that the LNBA as implemented in each IOU Demo B project is consistent with the specific CPUC requirements for the Demos. These requirements were primarily established in an Assigned Commissioners Ruling dated May 2, 2016, with some minor changes implemented through an Assigned Commissioner's Ruling Dated August 19.

Recommendation	**IOU Demo B Projects Satisfy all CPUC Requirements**
Consensus?	Consensus (SCE and PG&E); Non-consensus (SDG&E)[15]
Action type	CPUC Policy
Description	The WG recommends that the CPUC formally recognize that IOU Demo B projects and reports are fully compliant with CPUC directives and requirements as set forth in the May 2nd and August 23rd ACRs, wherein the IOUs are asked to evaluate DERs in locations against planned utility upgrade projects. Additionally, the methodology used in Demo B is appropriate to use provisionally in related IDER and DRP pilots that have been identified in the near-term, including IOU's Demo C and the Distribution Investment Deferral Framework.
Supporting Arguments	See IOU Demo B Final Reports for complete explanation of how each project and report complies with the requirements. PG&E and SCE's demo projects have satisfied all requirements in compliance with the ACR.
Opposing Arguments	SDG&E still has not provided a fixed link to its LNBA map.

3.2 Use Cases

Objective
This section provides commentary on use cases for the LNBA tool and overall methodology.

3.2.1 Use Cases Discussed During Development of Demo B

Discussion
In completing the short-term activities, the IOUs developed an LNBA tool through Demonstration B in coordination and consultation with the WG. The LNBA tool is designed as a public tool and heat map utilizing public indicative values. The tool and heat map does not provide market-sensitive information, nor does it provide confidential data from utilities. WG members have been presented with the following set of applications for the LNBA tool, as proposed by the IOUs during the May, June, and July 2016 WG meetings:

[15] Ibid, Footnote 14.

1. **LNBA Public Tool ("tool") and heat map to provide public information:** LNBA provide a heat map and data that customers and DER providers can use to identify potential optimal locations for deploying DER, along with detailed information about the required attributes necessary to achieve upgrade deferrals. Demo B provides an example of this use case. The final public heat maps are a feeder-level visual representation of where DERs can defer or avoid planned utility infrastructure projects. Deferral opportunities would be identified in the Distribution Investment Deferral Framework (DIDF), currently under development in DRP Track 3, Sub-track 3. The developed LNBA tool serving this use case employs public data and indicative values to identify locational and system-level benefits, in addition to specific identified project deferral value where applicable. The tool is technology-agnostic, and users may input a profile representing a specific DER or portfolio of DERs in a location to receive technology-specific estimates of the avoided cost, or that their DER project would provide. Data available for use in the LNBA tool that shows hourly load reduction needed in a given location to defer a planned upgrade may help developers create DER solutions that are designed specifically to defer or eliminate that planned upgrade.

2. **Prioritizing DER deferral opportunities:** Components of the LNBA methodology may be used to develop a prioritization of DER deferral opportunities by utilities. Specifically, the analysis of T&D benefits that drives the LNBA tool relative to the magnitude and duration of required electrical characteristics to achieve cost deferral may be useful in prioritizing deferral opportunities. This prioritization process is a step in the Deferral Framework as proposed by the IOUs in the Deferral Framework Workshop (organized by CPUC as part of Track 3, sub-track 3). As with other steps in the Deferral Framework, the prioritization process would be reviewed with the Distribution Deferral Advisory Group (DDAG), a proposed stakeholder group in the DIDF that would provide feedback and advises the selection of deferral opportunities for solicitation via the Competitive Solicitation Framework (developed in the IDER proceeding). Some components of the tool would likely not be used in this process, for example, system-level components based on DERAC values.

The use cases described above require a clear understanding of the connection between the Deferral Framework and the LNBA tool. Both are based upon the same distribution planning activities and analyses: forecasting, needs assessment, and evaluation of alternatives to meet identified needs. The Deferral Framework will determine which of those needs may potentially be deferred or met by targeted DERs. The subsequent list of potentially deferrable projects, including the attributes required to achieve the deferral, will be an important input into the LNBA tool. The LNBA tool will combine the distribution deferral benefits and requirements with additional benefits related to the bulk system (transmission benefits, capacity benefits, CAISO market benefits.)

As a very detailed output of the distribution planning process that is shared publicly and is also used in part to help make deferral decisions that are subject to external stakeholder input, the LNBA tool and heat map can increase transparency in utility planning and provide some visibility into distribution planning.

3.2.2 Additional Use of LNBA Methodology

Discussion

The development of the LNBA Tool within Demo B represents a major step forward in providing DER developers with data on grid needs and indicative deferral values. However, it is emphasized that the LNBA tool addresses the narrow question of evaluating DERs in single locations against certain distribution upgrades that are already in IOU distribution system plans, and should not be construed as the advancement of a comprehensive, location-specific utility avoided cost calculator that could be used to proactively identify high-value locations for DER deployment. The LNBA tool as developed under Demo B was designed as a public tool, using public indicative values – it does not use or provide market-sensitive information, nor does it provide internal data from utilities. The tool as developed under Demo B is not appropriate to be used to support sourcing decisions.

During WG discussions, members of the WG reached disagreement whether the LNBA tool has any applicability outside of the two identified uses as developed under Demo B. To provide clarification as per the ACR16, the CPUC Energy Division developed a memo17 to expand upon this discussion, stating that "a number of Commission proceedings and initiatives are looking to the LNBA to develop location-specific avoided cost values for use in various cost-effectiveness analyses to indicate high-value locations for DER deployment, inform resource procurement decisions, and develop location-specific rates or tariffs for DERs." These specific proceedings/initiatives are discussed below. The full memo may be found in the Appendix.

3. **Integration of Distributed Energy Resources (IDER) proceeding (R. 14-10-003):** the IDER identifies that LNBA may be used in the 1) development of a unified cost-effectiveness framework18 that can be used for technology-agnostic resource evaluation, and 2) identification of tariffs, contracts, or other mechanisms for the deployment of cost-effective DERS, and cost-effective methods of effectively coordinating existing Commission-approved programs, incentives, and tariffs to maximize locational benefits and minimize incremental costs of DER resources;
4. **Net Energy Metering 3.0 (D. 16-01-044):** the NEM successor tariff decision cited the ongoing work in DRP and IDER to defer significant changes to NEM incentive levels. Development of the NEM successor tariff is expected to consider LNBA-derived locational values;
5. **Integrated Resource Planning (R. 16-02-007):** Future cycles of the IRP process post-2018 may utilize locational values as an input to help inform resource net cost estimates.

While the WG has reviewed the CPUC Energy Division memo and understand to some extent where LNBA methodology may have future application, the WG has not comprehensively studied each use case and determined which refinements (and at what level of granularity) may be applicable for each use case. The WG acknowledges that all options may remain on the table given that further clarity is needed

---

[16] ACR Page A38 states: "Energy Division may provide further direction regarding the content and format of the report."
[17] ibid,at pp. 3
[18] R.14-10-003 Order Instituting Rulemaking, October 2, 2014, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M116/K116/116116537.PDF, p. 11.

around potential future use cases. However, certain IOU parties believe that LNBA is a tool to provide indicative information to various stakeholders, but that it should not be used in any sourcing decisions or DER compensation decisions.

The WG proposes that it spend a significant amount of time in the long-term refinement phase to determine how the LNBA tool and map may meet the needs of the use cases identified for the LNBA, pending additional guidance from the Commission. The WG requests additional Commission guidance on whether the LNBA tool may have additional uses outside the two identified from Demo B, and if so, to provide relative prioritization of expected uses of LNBA in the future. This guidance will assist in facilitating WG discussion within this scoping exercise and allow the WG to have a more informed discussion on prioritization, as well as which refinements are feasible to implement within certain time frames.

It is important to identify time considerations such as improvements that need to be made before future iterations of the tool are made, within the context of IOU ability to develop and incorporate changes, and in relationship to proposed timing of other proceedings. Some WG members also feel it is important to identify specific refinements and methodological changes that need to take place to enable the future use case, including the potential development of new methodological approaches, given that, per the Energy Division memo, the LNBA is envisioned to provide an avoided cost value to indicate high-value locations for DER deployment, inform resource procurement decisions, and inform development of programs, rates or tariffs for sourcing DERs.

The WG spent significant effort reviewing the LNBA methodology and tool in the context of Demo B in 2016, and collectively agree that the LNBA methodology as developed is not yet sufficient to meet identified use cases, and can only do so after addressing the methodological changes and improvements to the tool. In addition, WG participants have identified a number of cross-cutting issues related to the use cases which are not clearly within the WG scope, but present a challenge when considering how LNBA can be linked to programs, tariffs and rates in a way that satisfies the objectives of section 769 – deploy cost-effective DERs that satisfy distribution planning objectives; coordinate existing programs, incentives and tariffs to maximize locational benefits and minimize incremental costs of DERs; seek net benefits to ratepayers. Several of these are provided below:

- How do we ensure that DERs reliably provide distribution services, and how do field demonstrations help test this capability?
- What is the nature of interactions between current programs and cost effectiveness and future targeted programs and granular cost effectiveness? Does one replace the other? Do DERs adopted under one vs the other need to be differentiated? Does introducing a granular T&D avoided cost in cost-effectiveness require re-evaluation of the generic T&D avoided cost?
- How are targeted programs, tariffs, rates crafted to ensure that benefits are truly captured when needs are very dynamic and very specific in location, timing and duration, and how does LNBA enable this?

Members of the WG have differing opinions on whether future refinements to the LNBA tool to support its uses in sourcing should reflect public indicative values, or actual values that may be considered market-sensitive data, or internal utility data. From the IOU perspective, using confidential data would mean the results of the analysis could no longer be shared with the public. Many other members of the WG believe that the use of LNBA as a tool to support sourcing options may require more detailed and accurate locational values (some of which may be internal or market sensitive), and that the WG should fully consider potential future uses of the tool to direct DER deployment in a manner that maximizes net benefits before limiting which values the tool may use.

Recommendations

Recommendation	**Refine tool to support how LNBA may inform future sourcing options**
Consensus?	Non-Consensus
Action type	WG to analyze further
Description	Many refinements are identified in this document which support improvements to the LNBA tool so that it may provide the most value within the utility planning process and meet the needs of the tool to support sourcing options (as currently defined through the Energy Division memo). The type of sourcing option will determine cost visibility for utility planners as well as what timeline and reliability a planner can consider a DER able to provide. All this information will be critical to ensuring the best planning decisions are made. This would provide the necessary linkage between the LNBA and IDER processes, ensuring informed and effective decisions can be made regarding various potential sourcing options. One such linkage relates to improving the locational granularity of avoided cost in the IDER cost-effectiveness track. Another linkage relates to other DER sourcing mechanisms that may be developed in the IDER, such as location-specific DER programs or tariffs. Until these improvements are made, the tool is not capable of meeting the broader application of LNBA beyond the current Demo B scope. The WG expects to evaluate how the LNBA tool meets the needs of future applications and accompanying modifications, as a priority item during long-term refinement. The WG has included a long list of potential refinements to the LNBA tool and methodology in this report, and plan to determine which refinements may be needed for which future use, and at what level of granularity. There are further questions regarding how these values would be reflected in a spreadsheet tool. The WG will address this as it continues to discuss uses of LNBA in long-term refinement and has already identified it as an issue of consideration within the intermediate status report on LNBA refinement.
Opposing Arguments	Some Parties believe that even with refinements, the LNBA tool cannot or should not be used in any form of DER sourcing.

Recommendation	**LNBA methodology and tool may be used on a provisional basis in IDER and DRP pilots**
Consensus?	Consensus
Action type	CPUC policy guidance
Description	The methodology used in Demo B is appropriate to use provisionally in related IDER and DRP pilots that have been identified in the near-term, including IOU's Demo C and the Distribution Investment Deferral Framework. The IOUs will endeavor to include the additional consensus refinements detailed in the *Bulk System Benefits: Refinement to existing LNBA Values* section.

3.3 Regulatory Process Recommendations

Objective

This section includes recommendations on an appropriate regulatory process including various steps that should occur prior to further implementation of LNBA.

Discussion

This section discusses connection and timing in coordination with the Distribution Infrastructure Deferral Framework. The DIDF will determine which grid upgrades are deferrable by DERs, which is an essential step prior to evaluating the benefits of those deferrals across the system using LNBA.

It is expected that full system-wide implementation of LNBA will require significant resources. There are many questions about modifications to LNBA; various modifications impact the cost of LNBA implementation. As the future scope is not yet well defined, neither schedule nor budget are well defined or understood. Members of the WG have suggested several means of defining a budget for further LNBA work – overall, it is recommended by all Parties that defining a scope and budget for future LNBA refinements to meet identified uses should include input from Parties and the PUC.

Recommendations

Recommendation	**Deferral Framework should be adopted before the LNBA tool and heat maps are deployed system-wide**
Consensus?	Consensus
Action type	CPUC Policy Guidance
Description	Prior to system-wide implementation, the Distribution Infrastructure Deferral Framework (DIDF) envisioned under DRP Track 3 should be adopted. The Distribution Infrastructure Deferral Framework is a key input into the LNBA and has yet to be finalized as part of Track 3 of R.14-08-013. As discussed in the IOU presentation at the Deferral Framework workshop, IOUs plan to use technical screens to identify which projects are

	deferrable. LNBA may have value in helping market participants provide input into the prioritization of deferral opportunities. The IOUs envision the use of LNBA within the Deferral Framework as the following, while stakeholders of the LNBA WG request additional clarity regarding the deferral process: • LNBA will start with the list of deferral projects and attributes, and add in indicative public values, to identify optimal locations for DER deployment. The projects used for LNBA is the same set of projects that is the output of the Deferral Framework. The LNBA will calculate the T&D benefit for each project using indicative values. The LNBA also adds in system-level values from the DERAC tool. These public values are not used in internal processes. CPUC adoption of a deferral framework is necessary so that IOUs and the LNBA WG have clear direction on how the LNBA analysis will be used in the distribution deferral process.

4 Short Term Activity: Improvements to LNBA

This section summarizes recommendations made after review of IOU Demo B reports that support improvements to the LNBA methodology and tool by refining existing bulk system benefits within the LNBA methodology, and improve how information is presented within the LNBA tool and corresponding heat map. The WG understands that many of these refinements will require additional resources and analysis to implement, and will not be in place to be immediately implemented if a Q1 2017 decision is made on these LNBA refinements. The LNBA should not be approved for system-wide implementation until multiple questions regarding its future use are addressed. The WG agrees to continue working on the following refinements within the long-term refinement period.

4.1 LNBA Tool Functionality: Improving the Heat Map and Spreadsheet Tool

Objective

This section discusses improvements identified so far to improve how information is presented on the heat map and in the LNBA tool. This section does not consider changes to the underlying benefits analysis; those recommendations are discussed in the "Analytical Scope and Additional Benefits" section.

Two categories of improvements are made: 1) refining the tool to improve its accuracy; 2) determining further revisions to the tool and map.

Discussion

The spreadsheet tool created as part of Demo B allows stakeholders to develop a profile for a DER project and evaluate it against indicative values for deferring projects in the relevant distribution planning area that the utility has identified as deferrable. To show the results of Demo B on a visual map, IOUs color coded each feeder representing indicative LNBA results. The heat maps provide results over three time periods (short, medium, long term) and over two DER growth scenarios specified in the ACR. The maps are made publicly available and uses the same platform as the ICA map for ease of use. In addition, IOUs made feeder-level data publicly available through an online downloadable dataset.

The current LNBA tool is not designed to make assumptions about the performance of any particular resource. Rather, the LNBA tool provides information on the need, and the user can provide assumptions about a given resource. Sample profiles can be included in the LNBA tool. However, these would be “illustrative only.”

The LNBA tool requires users of the tool to provide basic DER information, benefits that the DER can obtain, and a DER hourly profile. One component that a prospective project developer is required to input is a “local area dependability” value under the “DER Settings and Full Local T&D Avoided Cost” tab. This input is meant to scale the DER profile up or down. As it is currently applied, the dependability factor does not actually reflect whether a project more or less “dependable”. Different DER types will have different impacts on load reduction based on many factors. Dependability metrics need to be defined to increase confidence level in projected DER performance.

Dependability is a sourcing question and therefore should be considered in discussions of sourcing mechanisms within the IDER proceeding (R.14-10-003). LNBA provides needed attributes. It is a sourcing question of whether any resource (or resource portfolio) provides those attributes. For competitive solicitations, IOUs will evaluate dependability as part of the bid evaluation process. For programs and tariffs, dependability assumptions should be established as part of the program rules.

The following revisions improve functionality of the map: 1) populating standard DER profiles to allow basic analysis by stakeholders; 2) modifying the tool so it can include multiple DER solutions; and 3) revising the tool to include VAR profiles for voltage-related upgrades. Finally, the WG requests that the Commission clarify how “integration costs” should be captured in the tool.

<u>Recommendations</u>

Recommendation	**Tool should include DER profiles and automatically populate output**
Consensus?	Consensus
Action type	IOUs to implement
Description	The Tool should include an option to select a typical or generic hour DER generation profiles and automatically populate output, rather than only having a manual input option. Ideally, the user would input a DER (solar PV, wind, solar PV+ storage, uniform generation, etc.) and the capacity of the DER (KW, MW) – the tool would then calculate an hourly generation profile and populate the fields, based on either local or state inputs. NREL’s PV Watt tool comes to mind

	and perhaps similar locational data could be incorporated for solar (or wind) in the tool. Sample profiles may be included in the LNBA tool. However, these would be "illustrative only." An actual resource would not be guaranteed to perform similar to the same profile. WG will review which profiles may be added in a resource library within the LNBA public tool, considering what resources may already exist (e.g., EM public tool, typical solar PV and EE profiles, etc.)

Recommendation	**Allow multiple locations / multiple projects**
Consensus?	Consensus
Action type	IOUs to modify tool
Description	The LNBA Tool should be refined to allow for modeling of a portfolio of projects, as a DER alternative to a larger distribution upgrade may require a portfolio of projects at numerous nodes. A combined portfolio of DER capacity may provide deferral at a substantially lower cost than a single offer, particularly if customer DER capacity is divided among multiple separate aggregators. Under the existing tool, if two DER capacities are offered, which individually would not fully meet a defined need but would meet the need as a combined portfolio, the capacities would receive zero valuation. The WG should enhance the LNBA tool to support benefit analysis of deferring a project with multiple locational elements.

Recommendation	**Include VAR Profiles for Voltage-Related Upgrades**
Consensus?	Consensus
Action type	WG to analyze further
Description	Demo B LNBA tool captures DERs' ability to defer voltage support projects, but only captures DERs' ability to reduce load via the user-input hourly DER profile, which does not capture of the ability of some DERs to produce or absorb reactive power as a way to avoid voltage-related investments (i.e. provide voltage support service). Incorporating tool functionality to take an 8760 VAR requirement input and DER VAR profile is not complex. However, developing that hourly VAR deficiency values will take additional engineering analysis. DERs can potentially provide voltage support in areas where customers experience low/high voltage conditions outside of Rule 2 limits. Voltage support services are planned capital investments needed to correct excursions outside voltage limits and supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems.

	In the existing LNBA tool, voltage support project deferral requirements are expressed in terms of load reduction rather than reactive power injection or absorption. This ensures that non-inverter-based DER technologies such as energy efficiency can be evaluated as DER solutions to deferrable voltage support projects.
Supporting Arguments	The May 2nd Assigned Commissioner's Ruling calls for "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: (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." As it was developed, the LNBA tool is unable to value these services, instead valuing voltage reduction only where possible through load management. Voltage support, which is already a component of LNBA, can be provided by reducing/increasing load (a capability that all DERs have) or by injecting/absorbing reactive power (a capability of DERs with smart inverters). This recommendation would expand the way in which the voltage support project deferral requirements are stated so that smart inverter-based DERs could provide meet the deferral requirements through reactive power management. Demo B only focuses on hourly load reduction needed to avoid a planned upgrade. This does not effectively capture the ability of some DERs to provide voltage support via VARs. DERs produce reactive power to avoid voltage-related investments. In addition to the load reduction requirement calculated in the LNBA Tool for thermal and safety constraints, the LNBA Tool should have a reactive power production requirement for voltage constraints. The ability for DERs to provide reactive power for planning purposes has yet to be determined. Other working groups, including ICA, are developing use cases to determine how DERs can potentially provide reactive power support. Increased visibility of voltage and reactive power levels is required throughout the distribution system to determine when and how IOUs would communicate with DERs to provide appropriate VAR levels in real time.

Discussion	**Clarify Renewable Integration Cost**
Consensus?	Non-Consensus
Action type	CPUC to clarify
Description	*Renewable Integration cost:* The 5/2/2016 ACR directed the IOUs to include "renewable integration costs" in the LNBA for Demo B.

	As described in all three IOUs' reports, the IOUs included the renewable integration cost adopted in D.14-11-042 in the RPS proceeding. These costs apply to stand-alone wind and solar resources, and reflect the increase in variable cost at the bulk-system-level associated with renewable integration. These do not represent "integration costs" associated with hosting or interconnection. Other WG members are unclear about the appropriateness of this adder in the LNBA, and whether this was the Commission's intention.

4.2 Bulk System Benefits: Refinements to Existing LNBA Values

Objective

Before being applied in any of the use cases, the LNBA requires refinement of values in the tool. This section identifies proposed refinements to two types of existing values:

- Certain benefits in the LNBA which currently use system level values from DERAC;
- Transmission values, which are included in the tool but for which the current methodology defaults to zero value.

These are values to the bulk system, including transmission benefits, capacity benefits, and CAISO market revenues.

4.2.1 Replace System Values with Local Values

Objective

The current LNBA tool uses system-wide values for certain benefits. This section discusses recommendations to replace those system-wide values with more localized values.

Discussion

The ACR identifies both a primary and a secondary analysis option for Demo B's LNBA methodology. Demo B primarily focused on the transmission and distribution avoided cost component, which is broken down as follows: 1) sub-transmission/substation/feeder level; 2) distribution voltage/power quality; 3) distribution reliability/resiliency; and 4) transmission-level.

While the ACR includes other avoided cost components, Demo B focused on the identified avoided T&D components due to their high variance between specific locations. Other avoided cost components (avoided generation capacity, avoided energy, avoided GHG, avoided RPS, avoided ancillary services) directly use values created under the DERAC tool. The IOUs referred to these components collectively as "system-level avoided costs."

The WG recommended that additional components of avoided costs, which currently employ system-level values, should incorporate additional locational granularity.

Recommendation

Recommendation	**Develop locational specific avoided cost values for energy and capacity**
Consensus?	Consensus
Action type	IOUs to implement modification to tool
Description	Update certain system-wide avoided costs with more locational specific avoided costs. More specifically, locational avoided costs for energy, capacity should be developed using locational information such as CAISO LMPs and local RA data. The Demo B "primary" level of analysis potentially undervalues avoided energy, as LMPs tend to be higher than system average prices owing to congestion and line losses. Also, local resource adequacy values will serve to better capture generation capacity value in constrained areas.

Discussion	**Assess variability in location specific line losses**
Consensus?	Consensus
Action type	WG to analyze further
Description	Line losses downstream from CAISO nodes raise avoided energy cost above system averages; however, in Demo B, IOU-specific average distribution line loss factors were used. Many parties in the WG expressed desire to have the LNBA tool generate line loss reduction information for any DER being deployed at any location in the entire system. The system average line loss adder used currently is not a genuine reflection of the line losses reductions most DERs will create in order for the LNBA tool to be the more accurate, some enhancement of the line loss calculations should occur. The WG acknowledges the need to first address the relative value of this analysis before inclusion into the tool, as the additional value variations that location-specific line losses provide may be very small relative to total project costs. Consequently, the WG proposes that a first step should be to estimate the variability of this parameter across the system to understand the benefits of enhancing the LNBA in this way vs the cost. Within long-term refinement, the WG will aim to determine whether there is enough variability in line losses in specific locations to understand whether line loss variability should be implemented in the LNBA tool.

4.2.2 Avoided Transmission Capital and Operating Expenditures

Objective

This section considers methodological approaches to determining the potential avoided transmission cost that may be achieved through targeted DER deployment.

Discussion

The LNBA methodology as demonstrated in the IOU Demo B projects include multiple location-specific value components building upon DERAC. For avoided transmission capital and operating expenditures, the ACR guidance specifies that 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 CAISO 2015-2016 transmission plan, Section 7.319 materialize as assumed in those locations."

It was concluded that the transmission plan did not identify specific projects that would be required in the absence of preferred resources or associated project costs, or provide information needed to develop DER load reduction requirements. Instead, the LNBA Tool contains a user input for a generic system-wide transmission benefit within Demo B. The value in the field is zero when the LNBA Tool is downloaded, but this does not imply that zero is the correct value or a default value. This is similar to the user input for avoided transmission in, the NEM Successor Tariff public tool (R. 14-07-002). The field was not pre-populated with a value but it was understood that no value should be considered "default," zero or otherwise. However, the WG agrees that the actual value of DERs in avoiding transmission costs is non-zero. For example, system-average marginal transmission costs have been estimated in the past through prior IOU GRCs,20 and distributed solar studies21 22.

The WG is in consensus and has placed high priority for determining a non-zero locational transmission benefit value as a long-term refinement item. To develop this value, the WG will focus on 1) understanding the shortfalls of the transmission system capability associated with the distribution facilities being analyzed; 2) developing a potential methodology for inclusion, 3) testing the functionality of the methodology within the LNBA tool; 4) ensuring that any avoided cost value adopted reflects the ability to actually avoid transmission cost in the near or long-term; and 5) coordinating with and understanding how CAISO's transmission planning process reflects contribution of DERs to avoid or defer actual transmission investment.

---

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

[20] SCE's 2011 recent GRC (A. 11-06-007) shows a marginal cost for CAISO-controlled transmission of $59.18 per kW-year (2012 $). See A.11-06-007, SCE Workpapers, "MCCR" sheet, "Input Sheet" tab, cells D17-D19.

[21] See the San Diego Distributed Solar PV Impact Study (Black & Veatch and Clean Power Research for the Energy Policy Initiative Center, University of San Diego School of Law, February 2014) at p. 38, Table 18, which calculated a marginal cost of CAISO transmission for SDG&E of $102.83 per kW-year

[22] August 2015 Vote Solar and SEIA analysis found marginal CAISO transmission costs of $87 per kw-yr.

Recommendation

Recommendation	Form technical sub-group to evaluate potential methodologies for avoided transmission costs
Consensus?	Consensus
Action type	CPUC and CAISO Policy Guidance
Description	As mentioned, the WG places high priority in ensuring that the CAISO TPP evaluates locational avoided transmission costs within its long-term TPP refinement activities. To support the CAISO TPP process, CPUC should seek CAISO approval for direct formation of a CAISO technical sub-group including IOUs, CAISO, and interested parties. Team will evaluate potential solutions that (1) focus on avoided the need for incremental transmission projects (i.e., not including existing projects or existing transmission revenue requirement) and (2) identifies the extent to which DERs in certain locations can avoid the need for such future projects. This subgroup will also consider whether transmission value can be captured through a location-specific value, system-level value, or through both a system-level value and at a locational-specific-level value. This envisioned subgroup would report findings back to CAISO and the broader LNBA WG.

The following are suggested starting points and considerations for methodology development. The WG has not yet held substantive discussions on this topic as a group, but provide additional detail on each of these discussion points.

- The broader cost-effectiveness framework may include a system-wide transmission value. Reducing transmission load provides both system-level, as well as location-specific benefits. Additionally, incorporating a reasonable proxy value in the interim as location-specific values are developed may be useful. The WG agrees that a proposed system-wide value must reflect actual avoided costs to ratepayers.
- One proposed place to begin analysis is to base avoided transmission cost on CAISO transmission revenue requirement allocated by CAISO coincident peak and/or specific location.
- Marginal CAISO transmission costs can be calculated based on a regression of the CAISO base transmission revenue requirement (TRR) as a function of CAISO coincident peak in the same period. This regression can use both historical and forecasted TRR data as a function of coincident peak demand, similar to the regressions that have long been used to calculate marginal distribution costs in CPUC ratemaking. While TRR data can differentiate between "reliability", "economic" and "policy-driven" CAISO transmissions designed to access renewable resources, DER deployment can reduce transmission investment in all three categories. Consider allocating the transmission revenue requirement socialized across the system only to the specific line segments identified.

- The proposed methodology using CAISO's transmission revenue requirement does not represent the marginal transmission cost nor location specific transmission project deferral value. Transmission revenue requirement represents the costs of transmission already built. DERs cannot defer projects that have already been built; this approach would be crediting DERs with value they simply do not provide.
- Focusing on low-voltage networks and/or transmission constrained areas may provide a good starting point. Focusing on the low-voltage transmission network and transmission constrained areas would provide greater transmission avoided cost. Limiting scope to specific sub networks will limit variables and potentially make generating the load reduction criteria easier to calculate. However, an ideal methodology would account for all transmission projects and transmission-level costs. It may be worth discussion of whether non-deferral benefits may be added to the avoided transmission cost methodology. These may include the value of providing frequency response, frequency stability, and other services. However, many WG members also indicate a need to focus the methodology on attributing real avoided cost values to DERs where they avoid or defer cost to ratepayers.
- It is maybe useful to develop or enhance existing software to be able to run a power flow analysis that can determine what series of load reductions could defer transmission projects, in collaboration with CAISO. Developing a methodology similar to the one created for distribution deferral calculations will make the LNBA easier to interpret for DER developers and utility planners alike. Ideally the automated tool will be able to run thousands of DER scenarios to generate the most optimal set of load reductions at specific substations to defer transmission projects. If such a tool was developed the IOUs/CAISO could say with certainty that DERs installed at a specific location will achieve a hard dollar amount of deferral savings. These load reductions and transmission deferral values could be added as an additional LNBA layer in each of the IOU heat maps. Long-Term Discussion and Potential Refinements on LNBA Methodology

5 Long-Term Discussion and Refinements on LNBA Methodology

Per the ACR, one of the purposes of the WG is to continue to improve and refine the LNBA methodology. This longer-term work related to ongoing refinements to LNBA methodology may be conducted in parallel to Demonstration B, though not directly related.

These discussion items are related to expansion of analytical scope past that considered in Demo B, additional benefits for inclusion, additional means of valuing DERs, and how uncertainty within the distribution planning process may be captured. Given the diverse group of stakeholders that make up the LNBA WG, it is understood that a vast majority of these items do not have consensus. Considerations of their potential inclusion require additional guidance from the Commission regarding any potential future use of the LNBA methodology past the uses identified in Section 3.2.1.

Final discussion on these items, given their ongoing nature, will be included in the Final Report on Long-Term LNBA Refinement, as identified within the ACR. As the WG has had some discussion on these topics in parallel with the development of Demo B, they are summarized in the following sections.

This section of the report contains discussions and recommendations relating to modification and refinement of the LNBA methodology.

5.1 Consideration of Locational Benefits Beyond Those Identified in the Distribution Planning Process

5.1.1 Accounting for Uncertainty in the Distribution Planning Process

Objective

This section discusses the following potential refinements: improve the comprehensiveness and accuracy of the distribution capacity component of LNBA by capturing the effects of forecast error on planned distribution upgrades; capacity additions currently planned for future years may be cancelled as the plans are refined due to lack of need; and locations with no current planned capacity addition may require such an upgrade as distribution plans are refined due to an unforeseen need. In addition, values may need to be defined for needs that fall beyond the 10-year planning horizon of the utilities.

Discussion

The LNBA tool is based upon the distribution planning process. The forecasts underlying the planning analyses are by definition uncertain. Due to changing forecasts, it is possible that new projects may become necessary, adding to the value of DERs in that location. It is similarly possible that current projects may become unnecessary, reducing the value of DERs in that location. Furthermore, the current planning forecasts only extend 10 years; there is no analysis beyond the 10-year period though the DERAC provides for T&D benefits out to 30 years. This section considers recommendations to modify the tool to address these sources of uncertainty.

Development of the LNBA methodology requires making certain assumptions and developing scenarios for DER growth and value of DER to determine which planned projects may be deferred by DERs. IOUs' distribution load forecasting methodology, which feeds into the annual distribution planning process, determines growth projections over 10 years. Two different DER growth projections were used in Demo B, per ACR requirements. The IOUs then use peak load information and detailed hourly load profile data to understand load reduction need for future planned projects under each DER scenario. The WG recommends the following refinements to better incorporate uncertainty and inform decision making:

Recommendations

Discussion	**Examine methods to reduce uncertainty in planning and utility investment**
Consensus?	Non-consensus
Action type	WG to analyze further
Description	The LNBA working group should examine ways to reduce uncertainty in distribution and transmission planning, which primarily stems from forecast uncertainty.

Supporting Arguments	DER deployment can defer needs that may have otherwise materialized. Alternatively, identified needs that may have spurred DER sourcing for deferral can ultimately not materialize due to forecast error.
Opposing Arguments	Out of scope – load forecasting and DER scenario development are not part of LNBA, though they drive the distribution planning outputs used in LNBA. Forecasting topics are discussed in DRP Track 3.

Discussion	**Incorporate an uncertainty metric in the LNBA tool (for planned deferrable projects)**
Consensus?	Non-consensus
Action type	WG to analyze further
Description	The deferrable distribution upgrades which form the basis for distribution benefits in LNBA are uncertain. Upgrade projects planned for future years in one planning cycle may not be ultimately implemented because future planning cycles with updated load forecasts show a reduced need. When such forecasted projects are assumed to be deferrable and hence provide an opportunity for DERs to capture the associated benefit, the quantification of that benefit should not assume that the project is 100% certain. An uncertainty metric for future projects would increase the accuracy of quantification of T&D benefits in LNBA. The heat map should indicate not just the relative dollar amount of potentially deferrable investment but also the certainty of investment. Projects with the highest certainty (as informed by the deferral framework criteria) *and* dollar amount may be prioritized for DER deferral. The forecast in and of itself is somewhat uncertain and has some inherent error. This topic should be coordinated with Track 3 Sub-track 1 on Forecasting and DER Growth Scenarios, focusing on aligning and developing a better planning forecast to assess system constraints. As the forecast continues to be refined, projects should become more certain. However, near term projects will always be more certain than projects identified further in the future.
Opposing argument	Prioritizing deferral opportunities is an issue for the Track 3 deferral framework and is out of scope. This recommendation makes sense only in tandem with the following recommendation as a counterbalance to the inclusion of value for deferring projects that were not foreseen but would have been become necessary.

Discussion	**Develop a methodology to incorporate deferrable projects that may occur unexpectedly (i.e. unplanned projects)**
Consensus?	Non-consensus
Action type	WG to analyze further

Description	As described above, due to forecast uncertainty, planned upgrade projects for future years are uncertain. Because projects toward the later years in a utility's ten-year distribution upgrade plan tend to be less concrete than those in the earlier years, the utilities in Demo B focused on near term projects.[23] Forecast uncertainty also results in new, unanticipated upgrade projects emerging within the forecast horizon in future planning cycles due to updated load forecasts. The IOUs should develop a method to quantify the likelihood of an unplanned project emerging in a location based on forecasted conditions and forecast uncertainty.
Supporting Arguments	The May 2nd Assigned Commissioners Ruling called for "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."[24] In order to properly value DERs, the LNBA must measure the avoidance of upgrades that would have been needed without DER growth but were not planned for ten years or were never proposed in utility distribution plans. Some distribution upgrades are not identified in annual distribution planning. These short lead-time upgrade projects are not considered deferrable by DERs. However, DERs that may not defer a planned upgrade at the time they were installed may actually reduce demands on a feeder and reduce the need for the IOU to perform an unexpected upgrade. LNBA methodology should include the value of DERs in avoiding or reducing the likelihood of unplanned distribution upgrades. In the long-term, DERs may reduce utility loads such that T&D upgrades that would have been required in the absence of DERs never even need to be considered in the utility planning process. Likewise, needs will be identified and projects proposed in the future. However, these needs capture only a portion of the T&D costs that DERs can avoid. Where increasing load growth would otherwise result in triggering future mitigation project planning absent DERs, earlier DER deployment or operation relative to the without-DER case can delay or avoid the need for upgrades. Thus, DERs can avoid more than the projects

[23] For example, six of nine deferral opportunities studied by PG&E are scheduled for 2018, and the three others are planned for 2019, 2020 and 2022.
[24] May 2nd, 2016 Assigned Commissioner's Ruling, p. 36

	identified as deferrable in the current T&D plans. This value should be recognized through long-run marginal transmission and distribution costs, and handled with long-term avoided T&D values that serves as a "baseline" or "background" to which more specific locational deferral values are added. To ignore these long-term avoided T&D costs that never rise to the level of deferrable projects in utility plans would understate the benefits of DERs. In addition to load-driven needs, needs for DER integration will be identified and projects proposed in the future where existing grid capacity reaches saturation. Where increasing customer demand would otherwise result in triggering future mitigation project planning, earlier changes in DER deployment or operation relative to the base case can delay or avoid ever reaching this threshold. This value should be recognized. While less precise than the cost of specific project proposals, areas approaching saturation can be clearly identified based on the rate of growth and existing capacity headroom. Mitigating such projected customer demand has less urgency than in areas where upgrade thresholds have already been crossed, and the value of such mitigation should be proportionately discounted, but should not be ignored. Beyond capacity upgrades, there may be opportunities to use DERs to allow for the downsizing of replacement equipment and thereby avoid larger capital expenditures. For example, if an upstream distribution facility fails and needs to be replaced, then the IOUs' distribution engineers would not necessarily specify replacement equipment with equipment of the same capacity as the failed device. Instead, they would account for DER on the feeder and may result in the replacement facility being smaller and less costly than a "like-for-like" replacement. The Demo B reports do not attempt to quantify such benefits. In future versions of the Tool, there should be proxy value that reflect the potential benefits of DERs avoiding these unexpected upgrades or allowing for the installation of less costly equipment in the event of an unexpected equipment failure. Finally, LNBA inputs and methodology must be refined to account for projects which materialize between planning cycles.
Opposing Arguments	Quantifying avoided costs as described above are purely speculative as projects in those scenarios were never developed. The planning forecast is made up of both DER and load, both of which change for each year the forecast is developed. To determine if projects under the scenarios explained above were avoided by decreasing load or higher DER requires a comparison of multiple years of forecast and recorded data, the historical load and DER profiles would then need to be separated to understand how each impacted the ultimate distribution profile. Next, an entire planning analysis would be required for a scenario without DER to determine if the removal of existing DER could have contributed to a new project identified in this "no DER" scenario. These tasks would require a significant increase

	of resource dedication to complete. This recommendation is requesting an avoided cost calculation for projects that were never developed while also establishing if the cause of why these projects were never needed is due to increasing DER or reducing load growth. The incremental cost savings of downsizing any particular piece of equipment are quite modest. Furthermore, given that ultimately load tends to grow, downsizing replacement equipment may actually be adding to the long-term cost, as in the future another replacement may become necessary to upsize the equipment. Utility investments are "lumpy" by their nature. When an equipment replacement is necessary, it generally does not make sense to downsize equipment. In addition, downsizing equipment would then reduce the hosting capacity of that particular distribution equipment. If the scenario arises where DER is then causing the need for more capacity, the smaller distribution equipment would then need to be replaced. This would make the distribution system less robust at accepting both increases in load and DER. At minimum, this benefit would require significant additional study and analysis to ensure that downsizing does in fact increase expected ratepayer benefits.

5.1.2 Incorporation of Additional Values into LNBA

Discussion	**Value locational value of DERs beyond 10 years**
Consensus?	Non-Consensus
Action type	WG to analyze further
Description	System-level avoided costs in the Demo B LNBA tool extend for the life of a DER solution. For distribution benefits, the tool identifies deferrable upgrades needed, forecasting out up to 10 years, in alignment with current IOU distribution planning windows. Calculation of avoided costs should extend to the end of project life. The LNBA tool could use system average values to calculate avoided costs between Year 11, to the end of the project.
Supporting Arguments	The Distributed Energy Resources Avoided Cost calculator includes system wide averages for transmission and distribution values that extend out 30 years. This reflects the fact that, by reducing load, many DERs will have benefits beyond the distribution planning process's 10-year window by avoiding projects that would have otherwise occurred due to load growth.
Opposing Arguments	The LNBA currently includes non-deferral benefits beyond 10 years, and the deferral benefit, when calculated using the Real Economic Carrying Charge (RECC) method, captures the benefit of deferral throughout the life of the deferred asset. The distribution electric system configuration can change significantly over time, any locational distribution benefit beyond the 10-year planning window is highly speculative.

5.2 Distribution Benefits: Analytical Scope and Additional Benefits

Objective

This section discusses recommendations concerning the overall scope of the analysis that determines potential distribution benefits.

The current LNBA scope (as determined in the May 2 ACR) focuses on identifying the potential benefits of DER resources. This section considers recommendations to LNBA scope that go beyond identifying the benefits of DERs. (This section does not include recommendations concerning adding values related to the uncertainty of the planning process; such recommendations are considered in the Uncertainty section.). Additionally, this section includes other recommendations concerning the structure of the analysis.

5.2.1 Analytical Scope

Objective

This section addresses general cross-cutting and cross-cutting recommendations that do not fall into the more specific sections that follow.

Discussion

This section summarizes discussion regarding which DER growth scenarios should be considered, and whether LNBA should include the costs of DER penetration.

Recommendations

Discussion	**Include Cost of DER Penetration**
Consensus?	Non-consensus
Action type	WG to discuss further
Description	The LNBA should take into account the cost of DER penetration using various DER growth scenarios. This should be done first by increasing hosting capacity limits found in the ICA (if necessary) – when a feeder has hit the limit of hosting capacity, it should be investigated which limit has been violated, and how much it would cost ($) to increase the hosting capacity to avoid the violation. It could then be estimated how much the hosting capacity has increased under DER growth scenario (MW) and the cost to do this ($). The cost to integrate various levels of DER could thus be estimated. Additionally, some of these costs may be avoided or deferred by DERs themselves. These could then feed into the LNBA tool. It must be

	determined which violations are deferrable with DER's themselves (e.g. by modifying generation output, with smart inverters, storage, etc.).
Supporting Arguments	This recommendation links the ICA and LNBA tools. It is understood that the capacity to do so currently does not exist, but linking the tools does provide additional value.
Opposing Arguments	The IOUs understand that including the hosting capacity-related costs of incremental DERs would result in a more complete "net" valuation of those DERs; however, we do not current have the capability to estimate the cost of increasing hosting capacity system-wide on a circuit by circuit basis. Specifically, the IOUs do not have an automated capability to estimate the cost of increasing hosting capacity. Right now, this is a manual process that requires individual circuit analysis based on specific proposed projects. This is thus well beyond the scope of either the ICA or LNBA. This would also require performing the complete distribution planning process and DIDF as both processes feed into the LNBA calculation. Accounting for multiple DER growth scenarios will dramatically increase the amount of work not currently able to be performed by the IOUs with existing software tools. Finally, the development and inclusion of a methodology for this value may be outside the scope of the LNBA. The understanding of the WG throughout the development of LNBA is that the cost of DER development is not included in the net benefits analysis. This makes sense in the context of what the LNBA is and what it is not. LNBA is not a tool to make a go/no-go determination whether to build a DER system. Such a determination would include the cost of building the DER system.

Recommendation	**Use Base Growth Scenario Only**
Consensus?	Non-consensus
Action type	WG to analyze further
Description	LNBA methodology should use the base DER forecast to determine value of additional DER, rather than the high growth scenario
Supporting Arguments	The ACR defined two DER growth scenarios – a base DER growth scenario, and a very high DER growth scenario. In some of the IOU Demo B reports, it was determined that the impact of the very high DER growth scenario was not consistent or intuitive. Further, the high growth scenario depends on many policy interventions that cannot be assumed. Methodological choices for the high growth scenario and lessons learned from Demo B should be shared with the Track 3, sub-track 1 of the DRP.
Opposing Arguments	This is potentially a question for Track 3, sub-track 1 on load and DER forecasts or Track 3, sub-track 3 on integration of DRP into planning.

	The appropriateness of any growth forecast depends on the application of the methodology and tool.

5.2.2 Additional Benefits

Objective

In review of the Demo B Final report, the WG engaged in discussion regarding whether the current LNBA implementation under Demo B omits certain benefits provided by DERs. This section considers and summarizes discussion around those additional benefits.

This section does not contemplate the hypothetical additional value through consideration of "not yet identified" deferrable projects. This potential source of value is considered in the Uncertainty section (Section 5.1.1).

Discussion

Over multiple WG meetings, the joint IOUs consulted on and agreed upon electric services that DERS could potentially provide, for the purposes of Demo B. The ACR required the IOUs to consider the full range of electric T&D services that DERs can potentially provide that result in avoided costs. The values must include services associated with distribution grid upgrades identified in 1) the utility distribution planning process, 2) circuit reliability improvement process, and 3) maintenance process. The WG agreed to use the four grid services developed under the IDER Competitive Solicitation Framework (CSF) Working Group: 1) T&D capacity deferral; 2) voltage support; 3) reliability – back-tie services; 4) resiliency (microgrids).

The IOUs, in their final Demo B reports, also included a list of services DERs have the potential to provide, but did not include in Demo B, as well as a list of services DERs cannot currently provide.

Many WG stakeholders, in their final review of Demo B reports, recommended that LNBA also include means of evaluating additional grid services, to the best estimated non-zero value possible based upon a demonstrated methodology for quantification of indicative values if available, and reflecting the degree of uncertainty. The WG engaged in discussion on how and whether to include values to replace a zero-value where an industry-recognized methodology has yet to be established.

The WG also has yet to engage in full discussion, but anticipates to consider whether and how potential benefit categories should be considered. This includes discussion whether LNBA should focus only on benefits that represent actual avoided utility expenses, or whether LNBA should additionally include non-energy benefits. Those who believe that LNBA should only focus on values that directly reduce a utility's revenue requirement believe that only benefits that actually reduce revenue requirement lead to ratepayer savings. Further, societal benefits are largely not local. Understanding who receives these benefits, and how exactly these benefits are accrued, is valuable.

Moving forward, in developing methodology for these proposed values, it is important that the WG define the type of value derived (e.g., avoided utility expenditure) as well as who receives the benefit. Specifically, any value included in the LNBA need to specify whether it represents an "avoided utility expense" (CapEx or O&M) or some other kind of value, and should indicate the type and who receives the benefits (e.g. societal value, customer value).

This section considers recommendations first for *how* benefits should be considered, and then recommendations for specific benefits.

Recommendations

Discussion	**T&D values to be included in future modifications of LNBA Tool should only reflect grid services adopted from IDER Competitive Solicitations Framework**
Consensus?	Non-consensus
Action type	CPUC Policy Guidance
Description	There are many “potential” values that have been suggested. However, many of these proposed values do not have a clear means of quantification established due insufficient information, insufficient control infrastructure, or lagging regulatory processes. Values should only be included in the LNBA if they have an established, industry-recognized methodology for quantification. “Placeholder” values must not be used, especially if there is debate about whether the value is positive or negative.
Supporting Arguments	The LNBA tool is not designed to speculate on potential sources of value. For potential values that do not have a defined method of quantification, additional research and analysis is necessary to determine whether or not these values actually exist.
Opposing Arguments	Many services are currently represented as providing zero value. Where an industry-recognized methodology has not yet been established the best estimated value (or range of values) should still be used. To assign a value of zero when this value is not supported by any evidence is introducing an inappropriate bias. Further, there is not consensus over what qualifies as an “industry-recognized” methodology. The Commission should consider research on these values to determine their existence and magnitude (e.g., existing peer reviewed research on asset life extension).

Discussion	**Explore asset life extension/reduction**
Consensus?	Non-Consensus
Action type	WG further study required
Description	DERs, by reducing thermal stress on existing distribution equipment, may potentially extend equipment lifetime. Conversely, DERs could shorten an asset’s life through additional usage and strain. The impact of DERs on asset life should be explored.

Supporting Arguments	The IOUs identified this potential service in Demo B final reports, and noted that it is currently difficult to accurately quantify this benefit, recommending its further inclusion as a long-term refinement item. Some stakeholders have noted that there is already research demonstrating this value.
Opposing Arguments	Significant effort would need to be undertaken to study asset life extension/reduction. Further, there are significant concerns that a utility would replace aging infrastructure at a certain point regardless of DER deployment, which means DER's would be credited for a value they do not provide. Each DER impacts distribution equipment in different ways, complicating the analysis even further.

Discussion	**Situational awareness or intelligence**
Consensus?	Non-consensus
Action type	WG to study further
Description	This service was identified in the IDER CSF WG Final Report and in Demo B final reports, but not formally defined.
Supporting Arguments	It is expected that IEEE 1547 Smart Inverter standards are going to determine how to enable the data collection abilities of smart inverters. Furthermore, many DERs have metering equipment that can collect data with more granularity, and with lessor latency, than utility equipment. Through aggregators, DERs can provide this data to the utility potentially avoiding utility investments in telemetry and monitoring equipment and improving the utilities' awareness of conditions on the distribution system. Utilities do not have perfect information on grid conditions at all locations at all times. DER systems can provide additional information that is useful in evaluating local conditions. Hawaii provides a good example of this, where DER providers have made data available to utilities that has aided in grid management.
Opposing Arguments	This hypothetical benefit has not been discussed or even clearly defined within the context of the LNBA WG. To date, there is no analysis to provide any sense of the scope or magnitude of additional "situational awareness provided by DERs: there is no indication of the specific information that will be provided to IOUs, there is no indication of the format, quality or frequency of such information, and there is no indication of whether DER providers intend to provide this information freely or expect that IOUs will provided additional payments for this information. More critically, there is no indication of the *usefulness* of this information. How much information is necessary to begin to improve "situational awareness? How many DERs are necessary on a particular circuit in order to provide this level of information? What is the necessary level of reliability of this information?

	Finally, there is no sense of the *value* of this information. Does this information reduce ratepayer expense? How so? If not, do other parties somehow benefit from this information? How? These questions are complicated and challenging. It would be inappropriate for the WG to spend time on this matter.

Discussion	**Increased reliability (non-capacity related):**
Consensus?	Non-consensus
Action type	IOUs to implement change to LNBA
Description	Include benefits associated with increased reliability provided by DERs, e.g. through reducing the frequency, duration or magnitude of customer outages.
Supporting Arguments	The LNBA methodology should value increased reliability and location. For example, if a DER provides reliability service in a location where the cost or value of reliability is above average, to a relatively small set of customers but those customers have a high "value of service", then the value that the specific DER provides could be significant
Opposing Arguments	LNBA currently includes the value of increase reliability from DERs where DERs can defer or avoid an otherwise necessary investment to bring reliability up to an acceptable level. Right now, these are defined as investments providing back-tie capacity (a function which can enable switching operations to reduce the number of customers on outage) or microgrid services (a function which can reduce the frequency and duration of outages for remote customers with an unreliable connection to the grid). If a particular customer or set of customers places a value on reliability above the standard level that is provided, that customer can make investments in DERs to improve their reliability. This should not be a cost that other customers bear through additional incentives for that customer's DER investment.

Discussion	**Evaluate Planned Upgrades Meant to Accommodate Additional DER Growth**
Consensus?	Non-consensus
Action type	WG to analyze further
Description	Any planned upgrades that are due to the need to accommodate additional DERs on the grid, which may be avoided or deferred by DERs, should also be included as a deferrable project.
Supporting Arguments	
Opposing Arguments	Where upgrades are needed to accommodate DERs that increase load (e.g. to serve electric vehicles), such upgrades would be identified in the normal distribution planning process, and would already be considered deferrable in LNBA.

	In cases where upgrades are needed to accommodate DERs that are interconnecting as a wholesale resource, the DER owner/developer would be responsible for that upgrade cost, and should be able to take actions that would reduce that cost in the interconnection process. The remaining upgrades to accommodate DERs might be deferrable by DERs; however, there is not yet an established framework for identifying and planning for those upgrades. Today, these are identified and managed as they emerge. When a planning framework has been established, these upgrades could be considered as deferral opportunities. Wherever possible, a DER that is causing a problem that requires an upgrade should be required to take reasonable actions to mitigate that problem without additional compensation. Utility customers should not provide additional compensation to DER owners/providers to mitigate a problem they are causing and which could be easily mitigated.

Discussion	**Avoiding Maintenance Projects**
Consensus?	Non-consensus
Action type	WG further study required
Description	LNBA methodology should value benefits of DER in reducing the frequency or scope of future maintenance projects.
Supporting Arguments	Maintenance projects are not scheduled far enough in advance for DERs to defer specific maintenance needs. However, by reducing thermal stress, DERs can likely defer maintenance in many cases – this value should be quantified.
Opposing Arguments	There is currently no reliable evidence that DERs actually defer maintenance projects. At minimum, additional data and analysis must be gathered. However, it is quite possible that additional DERs *increase* the need for maintenance projects. In addition, there is no existing method to predict if a piece of distribution equipment will require more or less maintenance during the life expectancy of the DER connected to that piece of distribution equipment.

Discussion	**Downsizing Replacement Equipment**
Consensus?	Non-consensus
Action type	WG further study required
Description	LNBA methodology should value benefits of DER allowing for installation of less costly equipment in the event of an unexpected equipment failure.
Supporting Arguments	Installing DER on a distribution feeder reduces loading on upstream equipment. If an upstream distribution facility fails and needs to be

	replaced, then the IOUs' distribution engineers would not necessarily specify replacement equipment with equipment of the same capacity as the failed device. Instead, they would account for the fact that the DER is on the feeder and may result in the replacement facility being smaller and less costly than a "like-for-like" replacement. Total system load growth has been flat for a decade. Customer self-generation is one reason for that. In the long run, we may need a considerably smaller distribution system. DERs should receive due credit for their contribution to that downsizing.
Opposing Arguments	In theory, this benefit is possible. In reality, this benefit is likely to be small or non-existent: The incremental cost savings of downsizing any particular piece of equipment are quite modest. Furthermore, given that ultimately in the long-term, load tends to grow, downsizing replacement equipment may actually be adding to the long-term cost, as in the future another replacement may become necessary to upsize the equipment. Utility investments are "lumpy" by their nature. When an equipment replacement is necessary, it generally does not make sense to downsize equipment. In addition, downsizing equipment would then reduce the hosting capacity of that particular distribution equipment. If the scenario arises where DER is then causing the need for more capacity, the smaller distribution equipment would then need to be replaced. This would make the distribution system less robust at accepting both increases in load and DER. At minimum, this benefit would require significant additional study and analysis to ensure that downsizing does in fact increase expected ratepayer benefits.

Appendix

a. Parties Participating in the Working Group

The following stakeholder groups attended at least one meeting or webinar of the LNBA WG (parties involved in providing tracked-changes comments in drafting this report are formatted bold underline):

- ABB Group
- Advanced Microgrid Solutions
- Alcantar & Kahl
- AMS
- Artwel Electric
- Bloom Energy
- CAISO
- California Energy Storage Alliance
- California Energy Commission
- **<u>California Public Utilities Commission Energy Division (CPUC-ED)</u>**
- **<u>CPUC Office of Ratepayer Advocates (ORA)</u>**
- **<u>California Solar Energy Industries Association (CALSEIA)</u>**
- City of Burbank
- **<u>Clean Coalition</u>**
- Community Choice Partners
- Community Renewables
- Comverge
- Cross Border Energy
- DNV GL
- ECCO International Inc.
- Energy and Environmental Economics
- Electric Power Research Institute
- Energy Foundation
- Environmental Defense Fund
- Gratisys Consulting
- Greenlining Institute
- Helman Analytics
- ICF International
- Independent Energy Producers Association
- **<u>Independent advocates</u>**
- Independent consultants
- Integral Analytics
- Interstate Renewable Energy Council
- Kevala Analytics
- Lawrence Berkeley National Laboratory
- Lawrence Livermore National Labs
- MRW & Associates
- Natural Resources Defense Council
- Northern California Power Agency
- NextEra Energy
- New Energy Advisors
- Nexant
- Open Access Technology International
- **<u>Pacific Gas and Electric Company (PG&E)</u>**
- PSE Healthy Energy
- Quanta Technology
- Sacramento Municipal Utilities District
- **<u>San Diego Gas and Electric (SDG&E)</u>**
- **<u>Solar Energy Industries Association (SEIA)</u>**
- Siemens
- Smart Electric Power Alliance
- SoCal REN
- SolarCity
- Solar Retina
- **<u>Southern California Edison (SCE)</u>**
- Stem Inc.
- Strategy Integration
- Sunrun
- SunPower
- TerraVerde Renewable Energy
- **<u>The Utility Reform Network (TURN)</u>**
- UC Berkeley
- **<u>Vote Solar</u>**

b. Acronyms

AB: Assembly Bill
ACR: Assigned Commissioner's Ruling
CAISO: California Independent System Operator
CapEx: Capital expenditure
CPUC or PUC: California Public Utilities Commission
CSF: Competitive Solicitation Framework
DAG: Distribution Deferral Advisory Group
DER: Distributed energy resource(s)
DERAC: Distributed Energy Resources Avoided Cost Model
DIDF: Distribution Investment Deferral Framework
DPA: Distribution Planning Area
DRP: Distribution Resources Plan
ED: CPUC Energy Division
GRC: General Rate Case
IDER: Integrated Distributed Energy Resources
IOUs: Investor-Owned Utilities
IRP: Integrated Resource Planning
LNBA: Locational Net Benefit Analysis
NEM: Net Energy Metering
O+M: Operations and maintenance
PG&E: Pacific Gas & Electric
RECC: Real economic carrying charge
SCE: Southern California Edison
SDG&E: San Diego Gas and Electric
T&D: Transmission and distribution
TRR: Transmission revenue requirement
WG: Working Group

c. List of WG meeting Dates and topics covered

Meeting Date	Topic(s)
May 12 – 1:00pm-3:00pm Webinar (combined ICA/LNBA)	Opening meeting
June 1- 9:00am-3:00pm In person (combined ICA/LNBA)	First discussion of demonstration implementation plan before June 16th submission
June 9 – 9:00am-3:30pm In person (combined ICA/LNBA WG meeting)	Second discussion of demonstration implementation plan before June 16th submission
July 5 – 2:00pm-4:00pm Conference call (combined ICA/LNBA)	Call to discuss submission of demonstration implementation plan
July 26 – 9:00am-4:00pm In person	Discussion of submitted stakeholder comments on demonstration implementation plans Use cases (focusing on procurement use case) Grid services (6.1.b) E3 methodology Data & maps (6.1.a)
August 31 – 9:00am – 4:15pm In person (combined ICA/LNBA)	Clarification on use cases Initial scoping discussion on long-term refinement issues (6.2.1.(A-D))
September 30 – 9:00am-4:00pm In person (combined ICA/LNBA)	Demo B status update Data access discussion
October 19 - 9am-12:30pm (webinar)	Second scoping discussion on long-term refinement issues (6.2.1.(A-D))
October 27 – 12:30pm-2:30pm (webinar)	Grid services and project deferability criteria for Demo B
November 16 – 9am-12:00pm (webinar)	Review of outline Data (long-term refinement) Review of LNBA tool Avoided transmission cost component
December 13 – 1pm-2pm (webinar)	Status update
January 6 – 9am-4pm In person (combined ICA/LNBA)	Presentation of IOU Demo B reports
January 11 – 1pm-3pm (webinar)	Discussion on planning use case Presentation of LNBA Tool
January 20 – 9am-4pm In person (combined ICA/LNBA)	Discussion on use cases and recommendations
February 22 – 9am-12pm (webinar)	Discussion of WG Recommendations
February 27 -9am-1pm (webinar)	Discussion of WG Recommendations
March 2 – 9am-1pm (webinar)	Discussion of WG Recommendations

d. References

IOU Final Demo B Reports:

1. PG&E:
   - Final Demo B Report: http://drpwg.org/wp-content/uploads/2016/07/R1408013-PGE-Demo-Projects-A-B-Final-Reports.pdf
   - Map: https://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/DemoBMap/DemoB.html
2. SCE:
   - http://drpwg.org/wp-content/uploads/2016/07/R1408013-SCE-Demo-Projects-A-B-Final-Reports.pdf
   - DERiM Web Map: http://on.sce.com/derim
   - DERiM Web App – load profiles: http://on.sce.com/derimwebapp
   - Expanded DERiM User Guide: http://on.sce.com/derimguide
   - DRP Demo Results Library: http://on.sce.com/drpdemos
3. SDG&E:
   - Final Demo B Report: http://drpwg.org/wp-content/uploads/2016/07/R.14-08-013-DRP-Demos-A-B-Reports-SDGE.pdf
   - Map: http://www.sdge.com/generation-interconnections/enhanced-integration-capacity-analysis-ica

WG reference materials: All presentation materials, webinar recordings, participant lists, and Party comments on drafts of DRP WG reports can be found online at: http://www.drpwg.org.

CPUC Energy Division Memo on LNBA use cases: http://drpwg.org/wp-content/uploads/2016/07/CPUC-Memo-on-LNBA-Use-Cases-Feb-1-2017-mm7.docx

(End of Appendix E)