BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	)	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters	)	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)		
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	)	Application 15-07-005 (Filed July 1, 2015)
And Related Matters	)	Application 15-07-007 Application 15-07-008

LOCATIONAL NET BENEFIT ANALYSIS WORKING GROUP LONG TERM REFINEMENTS FINAL REPORT

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January 9, 2018

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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LOCATIONAL NET BENEFIT ANALYSIS WORKING GROUP LONG TERM REFINEMENTS FINAL REPORT

Pursuant to the *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 Proceedings*, dated June 7, 2017 (the ACR), San Diego Gas & Electric Company (U 902-E), on behalf of itself and Pacific Gas and Electric Company (U 39-E) and Southern California Edison Company (U 338-E) (collectively, the Joint IOUs, hereby submits the Locational Net Benefit Analysis Working Group Long Term Refinements Final Report (Final Report).[1]

[1] The ACR did not identify a specific date to file the Final Report. Rather, the ACR provided that "Long-term refinement discussions shall span six months from the date of the first Working Group meetings, resulting in the submission of the Final Long-Term Refinement reports." ACR, at p. 14. During the Integration Capacity Analysis and Locational Let Benefit Analysis Long Term Refinements Working Group processes, the parties worked toward a filing date for the final reports of January 8, 2018. That date marks the end of the six-month period for "discussions" identified in the ACR that would lead to the development and submission of the final reports. The Joint IOUs were unable to file this Final Report on January 8, but believe this filing remains timely based upon the ACR.

Respectfully submitted,

/s/ Jonathan J. Newlander

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On Behalf of San Diego Gas & Electric Company (U 902-E), Pacific Gas and Electric Company (U 39-E), and Southern California Edison Company (U 338-E)

January 9, 2018

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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 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. The IOUs submitted the results of their Demonstration B (Demo B) projects in December 2016. The locational net benefits analysis (LNBA) Working Group reviewed the Demo B results and submitted the LNBA Working Group Final Report on May 8, 2017. A June 7 ACR provided scope and schedule to the continued long-term refinement activities for ICA and LNBA. Concurrent with the Working Group process, a September 26 Final Decision on Track 1 DRP provided further direction on affirming two consensus[1] use cases and adding a third use case of LNBA to serve a cost-effectiveness use and update the DERAC tool, and set a separate process within the DRP Proceeding led by the Energy Division to consider methodology options to meet the third use case.

This document serves as the Final LNBA Working Group on Long Term Refinements (LTR) Report to the California Public Utilities Commission (CPUC). The Working Group is comprised of the California IOUs and interested stakeholders. Participant lists from each WG meeting may be found in Appendix A. This report summarizes recommendations on long-term refinement issues identified by the June 7 ACR to continue refining and improving LNBA methodology. Some of the long-term refinement issues pertain to the discussion of the third LNBA use case ("DERAC use case") and applicable methodology. Given the timing of the Sept. 26 Final Decision, this report will identify where some long-term refinement recommendations are deferred to this separate process in the DRP Proceeding.

2. Introduction and Background

2.1 Overview and Procedural Background

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)

[1] Use cases 1 and 2 were determined based on Working Group consensus that LNBA could be used to develop public heat maps and for prioritization of deferral opportunities for competitive solicitation in the distribution infrastructure deferral framework (DIDF). These are collectively referred to as the "deferral use case."

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 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.

Pursuant to Commission direction, the IOUs filed their DRPs as Applications, including a proposal to complete a Demonstration of their LNBA methodology ("Demo B"). Stakeholders provided input on the IOU proposals, leading to an Assigned Commissioner's Ruling (ACR) issued in May 2016. That guidance directed the IOUs to complete Demo B. The ACR also established the LNBA Working Group (WG) to monitor and provide consultation to the IOUs on the execution of Demonstration Project B and further refinements to the 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 (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.

In December 2016, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) submitted their final Demo B reports. These reports summarize Demo results, lessons learned, and the IOUs' recommendations on the methodology selection and feasibility of implementation of the LNBA across the entire distribution system. The LNBA WG reviewed Demo B results and submitted its LNBA Working Group Final Report in March 2017.

A June 7 ACR provided a new WG scope and schedule to the continued long-term refinement activities for ICA and LNBA. The LNBA Working Group has convened since July to discuss the identified long-term refinement topics from the ACR. Topics were prioritized in three Groups, with Group 1 being highest priority. The WG has met six times to discuss 13 topics. The June 7, 2017 ACR additionally established two pre-WG scoping documents and two interim reporting milestones. The pre-WG scoping documents were submitted June 22, 2017. The interim report on Group I topics was submitted August 31, 2017, and the interim report on Group II-III topics was submitted October 31, 2017. These documents may be found on the DRPWG website[2].

A September 26 Final Decision on Track 1 DRP provided further direction on affirming two consensus LNBA use cases related to identified project deferrals and adopting a third use case of LNBA to efficiently incorporate DER integration costs and develop location-specific T&D avoided cost values for input into DERAC, and set a separate process within the Energy Division to consider methodology options to meet the third use case. The Decision also included DER integration costs in LNBA, consistent with AB 327.

[2] http://www.drpwg.org/sample-page/drp

2.2 Scope and Process

The "Working Group" (WG) references all active parties participating in LNBA WG meetings, which include the IOUs, government representatives, DER developers, nonprofits, and independent advocates and consultants. Participant lists for each meeting may be found in Appendix A. The final report is the product of written proposals, edits and contributions from participants from the following organizations:

- CAISO
- CALSEIA
- Clean Coalition
- E3
- ORA
- PG&E
- SCE
- SDG&E
- SEIA
- Stem
- Tesla
- TURN
- Vote Solar

For each topic discussed, WG participants were asked to present their proposal to the full WG and develop a written proposal following. All stakeholders were invited to provide edits and comments to the developed proposals, or submit their own written proposal if opinions differed. Certain topics were revisited when additional discussion provided clarity or built consensus, or additional analysis was conducted to support or refine an initial proposal. All submitted written proposals and comments may be found in Appendix B.

3. Recommendations Summary Table

The June 7 ACR directs the WG to document the extent of discussions, reason(s) for rescinding or tabling the topic, and relevant considerations and/or implementation plans (if any) for further discussions and methodological development beyond the WG process.

The following summary table identifies the issues discussed, ACR group (the ACR identified priority topics for discussion by Group), which parties submitted written proposals and comments, which WG members have stated agreement or disagreement with the proposal, and recommended next steps for further development.

Table 1: Summary of WG Recommendations on ACR Topics

Topic	ACR Group	Proposals	Comments	Agree with proposal	Disagree with proposal	Abstain	Recommended Next Steps
Avoided energy	Group I Item 4.i	Joint IOUs		Joint IOUs			CPUC determination whether proposed timing aligns with IRP and IDER
Avoided capacity	Group I Item 4.ii	Joint IOUs	SEIA	Joint IOUs TURN	SEIA		CPUC review of proposals

Avoided line losses	Group I Item 4.iii	Joint IOUs	Clean Coalition	Joint IOUs			IOUS develop project-specific loss factor for deferral framework use; DERAC to be updated with public line losses as they evolve
Smart inverters: input hourly VAR profiles	Group I Item 2.iii	Joint IOUs		Joint IOUs			IOUs modify tool and method to calculate hourly VAR requirements profile
Automatic Input of DER Profiles	Group I Item 2.i	Joint IOUs		Joint IOUs			Include identified EE and solar PV profiles as described
Model portfolio of DER projects to meet single grid need	Group I Item 2.ii	Joint IOUs		Joint IOUs			Refine LNBA tool as described
Avoided transmission value	Group I Item 5	PG&E, SCE, SDG&E TURN SEIA Clean Coalition	CAISO	Deferred to ED Process			
Uncertainty metric	Group II Item 7	Joint IOUs		Joint IOUs		SEIA	For deferral use case: use of prioritization metric pending DRP Track 3 Decision For DERAC: deferred to ED process
Use of single or multiple growth forecasts	Group II Item 11	Joint IOUs		Joint IOUs			For deferral use: single scenario For DERAC: deferred to ED process
Smart Inverters: Conservation voltage reduction (CVR)	Group III	SEIA and Tesla	TURN Joint IOUs	SEIA and Tesla	TURN Joint IOUs		Additional discussion and CPUC decision needed
Smart Inverters:	Group III	Joint IOUs	SEIA and Tesla	Joint IOUs	SEIA and Tesla		

Situational awareness	Item 13	SEIA and Tesla	Joint IOUs	SEIA and Tesla	Joint IOUs		Additional discussion and CPUC decision needed
Asset life extension or reduction	Group III Item 12	Joint IOUs		Joint IOUs	SEIA – with regards to timing of implementation		Additional discussion and CPUC decision needed
Non-capacity related reliability	Group III Item 14	Joint IOUs	SEIA	Joint IOUs	SEIA		Additional discussion and CPUC decision needed
		SEIA	Joint IOUs	SEIA	Joint IOUs		
Valuing unplanned grid needs, value beyond 10 years	Group III Items A, 8, and 9	None (Discussion based)	CALSEIA	Non-consensus; deferred to ED Process			

4. Group I topics

The following topics were identified as Group 1 priority topics for WG discussion in the June 7, 2017 ACR: 1) locational avoided energy value; 2) locational avoided capacity value; 3) locational avoided line losses value; 4) incorporation of reactive power priority (VAR profiles); 4) automatic input of DER profiles; and 5) locational avoided transmission value.

4.1 Incorporate additional locational granularity into energy, capacity, and line losses system-level avoided cost values

4.1.1 Energy

The current avoided energy price forecast in the LNBA tool is taken from the 2016 DERAC calculator. The WG agrees that a more locational avoided energy price forecast should be used. This locational value should reflect the default load aggregation point (DLAP) price, as this represents the price IOUs pay to serve load. The IOUs engaged E3 in further analysis to develop two options on how to develop DLAP forecasts. These options were presented to the WG at the November meeting.

The first option uses a similar approach to the methodology used in DERAC. This proxy methodology would utilize recent historical or forecasted hourly DLAP energy prices modified by heat rate factors to obtain hourly energy prices forecasts. The heat rate factors would be obtained from the CPUC's Integrated Resource Plan (IRP) RESOLVE model. By utilizing the IRP RESOLVE model, the heat rate factors would incorporate the future impacts of California policy (e.g., SB350 and Governor's 2030 Greenhouse Gas Reduction goal). The proxy method would improve the current DERAC methodology (1) by providing more locational granularity (because it utilizes hourly DLAP energy prices) and (2) by utilizing updated heat rate factors that are consistent with the IRP. In addition, this proxy methodology could be implemented in a relatively short time. However, additional analysis of the results from the proxy methodology would be necessary to ensure the validity of the price forecast. For example, the Resolve model only uses 37 representative day-types to simplify the modeling. These 37 day-types would need to be matched to all hours of the year to develop the heat rate factors. When transitioning from one day-type to another, there is the potential for the price forecast to change suddenly due to the difference in day-types.

The second option would be to utilize a full annual, hourly production cost model to develop price forecasts. A production cost model simulates the grid by minimizing the cost of operating the grid subjected to constraints such as serving load, individual generator operational constraints, and transmission limits. Thus, a production cost model would be able to provide a more detailed and precise view of future prices, especially by location if locational price differences change over time in response to load, resource, or transmission changes. The IRP proceeding currently is planning to develop a SERVM model, a hybrid resource adequacy and production cost software, to further assess the impacts of scenarios on the grid and would also incorporate future effects of California policy which could potentially be leveraged to provide an energy forecast. While SERVM can provide an energy price forecast, the software is more focused on resource adequacy. Because of SERVM's focus on resource adequacy, it may be necessary to translate the SERVM model to a more dispatch based production cost model (e.g., PLEXOS, AURORA, or Gridview) which could provide a robust energy price forecast. The IRP's SERVM model is not expected to be finished until the middle of 2018. Additional vetting or analysis may need to occur to validate the results from any production cost model.

The WG discussed both options during the in-person meeting, and the Joint IOUs' presented a revised written proposal in November that considered an overview of findings by E3 to make a recommendation, for WG comment. This written proposal stated that the IOUs recommend using the first proxy methodology as an interim solution to provide locational DLAP forecasts, which is eventually replaced with the results from the IRP production cost model.

The IOUs' final recommendation is that the second option using an IRP production cost model results be used once it is ready and has been validated, assuming that the production cost model price forecast would be determined to be more accurate. Finally, the IOUs recommend that the development of the prices using the proposed phased approach should be done in annual update to the DERAC as part of the IDER proceeding. This would allow stakeholders to review the results of the methodology, leverage the existing process to update the DERAC, and fulfill the DRP Track 1 decision to inform the DERAC of improvements from the LNBA cost effectiveness use case. Once adopted in an updated DERAC, the LNBA tool would be updated to reflect the changes for the LNBA deferral use case.

With regards to next steps, the Commission should determine whether the proposed timing and development of methodology is appropriate and in line with the IRP and IDER proceedings.

4.1.2 Capacity

The WG explored available data to add locational variation to the generation capacity value. Currently, the only public source of generation capacity price information is the annual CPUC Resource Adequacy

(RA) report[3], which provides aggregated RA contract price information, at both the CAISO system-level and the local RA level. Although this report represents best available information, it is based on voluntary responses to a CPUC data request and does not necessarily capture the entirety of RA contracts and transactions.

Local RA best represents a locational RA product, as both the requirements (based on August peak load in the LCR area) and the product are specific to a location in the system. This capacity product can come from an LSE's generation portfolio and/or through contracts with generators to procure the RA-qualifying MW attributes of the generator. RA prices represent the short-run generation capacity avoided cost, since in the near-term, DERs increase or decrease an LSE's RA procurement.

The WG agreed that the available locational information applies to short-run generation capacity costs (i.e., RA prices in the CPUC RA report), but not to the long-run generation capacity avoided cost (expressed as the cost of new entry[4], or CONE). CONE estimates how much generation capacity would cost from a new generator by estimating the levelized annual cost of building a new generator, minus the levelized annual energy and ancillary service revenue the plant would be expected to generate. In any year, CONE represents the maximum generation capacity avoided cost. CONE cost components could be evaluated locationally to calculate location-specific variants of CONE; however, this is not done today. Currently CONE is also adjusted for losses in the DERAC from using utility-scale specific generation capacity loss factors.

The WG is in non-consensus with regards to a methodology to calculate location-specific avoided capacity. The Joint IOUs and SEIA have each submitted a proposed methodology.

The Joint IOUs propose to work with the CAISO to develop locational generation capacity avoided cost values at the CPUC Local RA areas, based on CAISO's Local Capacity Requirement Area (LCR Area) level. Areas outside of a Local RA area would receive CAISO system-level generation capacity avoided cost. IOUs will use the recent, joint-IOU system-level generation capacity price forecast that was provided as a benchmark in the RPS proceeding. Locational generation capacity avoided cost values will be determined using local RA multipliers developed from the most recent data in the CPUC RA Report and applied to a CAISO system-level forecast that includes both short-run and long-run capacity value. In each year, all generation capacity prices are capped at CONE. In the year that system-level generation capacity price forecast reaches CONE, all other areas are also set at CONE. The full methodology for developing locational factors can be found in the written proposal in Appendix B. This proposal also discusses interaction with an IDER Proceeding Decision (D. 16-06-007) on the use of short-run avoided generation capacity in the context of DER cost-effectiveness analysis.

SEIA notes that the IOU proposal uses location-specific short-run RA values, but a system-wide resource balance year (RBY). SEIA agrees with the D. 16-06-007 conclusion to eliminate RBY because distributed

[3] The latest RA report can be found here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942

[4] CONE estimates how much generation capacity would cost from a new generator by estimating the levelized annual cost of building a new generator, minus the levelized annual energy and ancillary service revenue the plant would be expected to generate.

energy resources are displacing new capacity rather than short-term capacity, and because the RBY concept fails to recognize the full value of small-increment, short-lead-time, high priority resources such as DERs. Instead, SEIA proposes to develop locational generation capacity avoided cost values at the IOU level of granularity based on the loss-adjusted Cost of New Entry (CONE) in each IOU service territory. Loss adjustments should be based on peak period line losses in each service territory from generation level to load level, as is currently done.[5] These IOU-specific CONE values would reflect locational differences due to (1) differences in peak period losses in each IOU service territory and (2) different CONE calculations given variations in CONE between service territories due to different siting costs, energy costs, environmental costs, or the base cost of the marginal source of capacity. SEIA states that this would be consistent with D. 16-06-007 which established the CONE as the avoided generation capacity cost for DERs, without the use of a Resource Balance Year (RBY) to transition from short-run to long-run avoided capacity costs that accurately value distributed energy resources.

TURN believes that the IOU approach is more accurate from an actual capacity value and need standpoint. TURN notes that the intent of this work in the DRP is to improve on earlier approaches, including the use of single system-wide long-term capacity value in D.16-06-007.

In determining next steps, it would be helpful for the Commission to further explore:

- For each proposal, does the proposed method reasonably reflect locational differentiation of avoided capacity cost? Does it accurately reflect DERs' ability to avoid costs? Is implementation feasible?

4.1.3 Line Losses

Within Demo B, the LNBA tool uses IOU system-wide, region-specific average loss factors for distribution and transmission. The loss factors were used to estimate the additional avoided energy costs, avoided generation capacity costs, and avoided T&D capacity needs at peak realized by a DER in reducing line losses. The LNBA WG expressed that using a system-average loss value did not account for DERs' ability to produce location-specific line loss reduction, and recommended exploring the issue in greater to detail to determine whether the additional granularity may be worth pursuing.

Over the long-term refinement period, the IOUs conducted additional line loss studies to increase understanding of how DER location may vary line losses across distribution feeders and the impact on secondary system losses. The purpose of these studies was to determine how loss factors may be included in the LNBA and whether a more granular, location-specific methodology is feasible and material.

The IOUs each conducted further study on distribution losses using the following steps:

1. Select a sample size of distribution feeders to evaluate in preliminary study
2. Define circuit types to reflect differing characteristics

[5] From the 2017 Avoided Cost Interim Update Documentation, "The capacity value is therefore increased by the PRM and the applicable loss factors for each utility." See: http://www.cpuc.ca.gov/General.aspx?id=5267

- i.e. Rural large service area, urban small service territory, and suburban medium size territory
- Uniform loading, spot load, express run circuit
- High % loaded circuit, medium %. Low %

3. Evaluate base circuit model for maximum, minimum, and median loading levels to see the baseline %/kW losses on each circuit
4. Model generation on baseline conditions created in #2
5. Record the kW losses from baseline condition determined from #2
6. Calculate maximum losses % change and min loss %
7. Use line loss study results to estimate sensitivity on LNBA results
8. Perform similar study for secondary network scaling generation and load

Some of the results of those studies are shared in the IOUs' full written proposals, found in Appendix B.

SCE's study was based on 15 representative mainline circuits, with a 1 MW generator modeled at each 10% impedance of the circuit from the substation. Observations were based on 4 kV lines versus 12/16 kV lines. SDG&E's study used similar parameters, but focused on three 12kB distribution substations in three distinct geographic regions of its service territory. PG&E additionally modeled the three phase system, including mainline and branches, to better incorporate the relatively diverse nature of PG&E's urban and rural regions into the study.

The joint IOUs presented the following overall conclusions from the additional study:

- For 4 kV distribution lines, the amount of distribution line losses was not significantly reduced when simulating a 1 MW generator at various locations.
- Adding 1 MW generator on 4kV circuit typically resulted in reverse power flow and increased distribution line losses.
- When DER generators cause reverse power flow through the distribution service transformer or the substation transformer, the total distribution line losses is likely to increase because DER generation exceeds the loading on the circuit it's interconnected, which will likely result in increased current flowing on a portion of the circuit, and in turn increase resistive losses.
- Rural feeders tend to be longer and higher impedance, and have more locations with high peak losses as well as overall variance in line losses to feed each line section.
- Back-feeding does cause losses to increase in certain locations on the primary distribution feeder, especially under moderate and low-load conditions.
- Urban feeders are typically stout, low impedance, short length, and have low losses so they are not highly location sensitive.
- Losses on the secondary network are mainly derived from net transformer loading and will be minimal when generation is coincident and sized to match load (i.e. load is fed from generation locally).

The LNBA WG recommends that, for the deferral framework and heat map use case, the LNBA tool could incorporate more locational differentiation of losses within the LNBA tool. For the cost-effectiveness/DERAC use case, the WG does acknowledge that there is variability not currently captured in DERAC, but for now the methodology should stay the same. The WG also discussed that, if more granular public line loss factors become available, there may be opportunity to incorporate those into the DERAC.

For the deferral framework use case, it is apparent that variation in line losses can be significant, particularly for more "outlier" locations. Thus, a project-specific loss factor for distribution deferral will be calculated. The means of evaluation would depend on the number of deferral opportunities and associated number of circuits that pass through the to-be-defined deferral screens in Track 3 of the DRP Proceeding (for example, detailed modeling may be feasible for a small number of deferral opportunities, but not dozens). Non-IOU parties discussed that this change could be included in the 2018 heat map and public tool.

4.2 Location-specific grid services for smart inverters – incorporating reactive power support (VAR profiles)

The LNBA WG grouped multiple ACR topics into the overarching "smart inverter" umbrella: Methods for valuing location-specific grid services provided by advanced smart inverter capabilities was grouped with 1) improve heat map and spreadsheet tool by allowing hourly VAR profiles to be input in order to capture DERs' ability to inject or absorb reactive power; 2) Conservation Voltage Reduction; and 3) Situational Awareness. Smart inverters are generally needed to enable each of these capabilities. Per the June, 7 ACR, it was agreed that developing a methodology to consider VAR profiles was of higher priority. Additional smart inverter capabilities, namely, conservation voltage reduction, are discussed further in the report as a Group III topic.

4.2.1 VAR profiles (reactive power support)

Voltage support is generally provided using capacitors or voltage regulators to maintain voltage within Rule 2 requirements. To defer a voltage investment using DER, the DER must either manage real power (e.g., using energy efficiency to help boost voltage by reducing load) or use smart inverters to provide both real and reactive power support. DER reactive power (VAR) capabilities are generally provided by DERs that utilize smart inverters.

The IOUs need to develop a methodology for calculating the hourly VAR requirement profile. The hourly VAR requirement profile will identify the VARs-needed hourly profile to defer an upgrade. This is dependent on both the IOUs' development of necessary tools and the Rule 21 requirements currently being considered. Rule 21 rules will develop reactive power requirements and power factor limits, which are required for the development of VAR profiles, and are expected to be finalized within R.17-07-007. However, the development of these functions is independent of the Rule 21 proceeding and the effective date of that Resolution.

The LNBA WG also agreed that the LNBA tool could be modified to accept a DER VAR profile and a VAR Requirements profile, by adding an hourly VAR profile and hourly real power (kW) under the User Input for DER Hourly Shape tab, and also modifying the tool to accept a VAR requirements profile and validating that the DER VAR profile input meets or exceeds this requirements profile.

4.3 Automatically populate DER generation profiles

The WG agreed that sample DER hourly profiles should be included within the LNBA tool within a DER Profile Library. The WG agreed these profiles would be illustrative only, and not considered to fully represent real world production. The tool should also allow profiles to be automatically populated.

The WG agreed that profiles should use public sources of information, be normalized to 1 kW, and be scalable by user input of size. Additional profiles can be added to the DER Profile Library to include emerging technologies or meet additional DER use cases. The WG agrees that additional DER profiles should be based on public sources, vetted, and readily available.

The WG agrees to include the following profiles immediately:

- Solar PV: The WG agrees that the National Renewable Energy Laboratory's (NREL) PVWatts Calculator [6] is an appropriate source of solar PV profiles. This calculator allows users to input a location, select appropriate weather data, and provide PV system properties (e.g., size, tile, DC/AC ratio). For the automatically generated profile within the LNBA tool, the WG agrees to default the following inputs:
    - Location: Los Angeles, San Diego, and San Francisco, selecting the nearest TMY2 location to the three cities
    - Array Type: Fixed (roof mount)
    - DC System Size (kW): 1 kW
    - Other PVWatts settings (e.g., system losses): Default

- Energy efficiency: The WG agrees that Energy and Environmental Economics' (E3) 2013-2014 Energy Efficiency Calculator [7] is an appropriate source for energy efficiency profiles. These hourly profiles represent the latest hourly profiles from the Database for Energy Efficient resources (DEER) [8], a CPUC database containing information on energy efficient technologies and measures relevant to California. The WG agrees to include the following EE measures or technologies within the DER Profile Library.

    - Residential HVAC Air Conditioning Efficiency for each of the three IOUs
    - Non-Residential Indoor CFL lighting for each of the three IOUs
    - The residential and non-residential EE profiles noted above are not for a specific climate zone in each of the IOUs. Instead, the EE profiles are for all of the IOU territory.
    - A flat shape normalized to one for all hours of the year.

[6] NREL's PVWatts Calculator can be found at: http://pvwatts.nrel.gov/
[7] E3's 2013-2014 Energy Efficiency Calculator can be found at: https://www.ethree.com/public_proceedings/energy-efficiency-calculator/
[8] DEER information can be found at: http://deeresources.com/

4.4 Enabling modeling of a portfolio of DER projects at numerous nodes to respond to a single grid need/method for evaluating the effect on avoided cost of DERs working "in concert" in the same electrical footprint of a substation

The WG agreed that the LNBA tool could be refined to support benefit analysis of a portfolio of projects at numerous nodes. The WG agrees that the following proposed modifications to the LNBA tool can provide for this analysis:

- To input DER portfolios, IOUs can modify the "User Input DER Profile" section on the DER Dashboard tab by addition multiple columns to allow additional user input of DER profiles and locations. This could allow the tool to consider multiple DERs of different types and locations in aggregate.
- For each new column, the IOUs could create user dropdowns to allow users to select a predefined 8760 hourly profile from a DER profile library to populate the column, so that using the tool will not require manual input. The profile could be normalized to 1 kW (see above discussion on "automatically populate DER generation profiles").
- Each column could include a cell to scale the DER profile up or down.
- The columns could aggregate into the DER profile column on the DER Dashboard tab to analyze the overall financial impact of the portfolio.

A flow factor matrix is used to evaluate the relation between separate DER projects. The WG discussed that these modifications could be included in the first implementation of the LNBA tool.

4.5 Form technical subgroup in long-term refinements to develop methodologies for non-zero location-specific transmission costs

4.5.1 Overview

A technical subgroup of the LNBA WG held 8 calls and 1 in-person meeting to discuss the potential avoided transmission value within a deferral use case and the potential avoided transmission value within a cost-effectiveness use case that extends through the entire life of the DER asset in LNBA.

The subgroup first met in July 2017. At this time, the WG endeavored to better understand the CAISO transmission planning process, including how the CAISO identifies projects for preferred mitigation alternatives. This discussion was thought of as more applicable to the use of LNBA in a deferral context. At this stage of the Track 1 process, the Commission had only noted that the WG was in consensus with regards to the existence and definition of a deferral use case of LNBA, and was in non-consensus as to whether the use of LNBA for cost-effectiveness evaluation was a CPUC-determined use case.

Subsequent to the September Track 1 Decision (D. 17-09-026), it was determined that the primary purpose and near-term objective of the subgroup should be to identify a value for the DERAC tool. The Track 1 Decision asks the IOUs to serve proposals for modeling and/or methodological approaches to achieve the third use case (use of LNBA in cost-effectiveness evaluation and in the DERAC tool). These proposals were due December 6, 60 days after the Decision.

The Decision orders the IOUs to file methodologies for developing DPA-level avoided T&D values for input into DERAC that match the lifespan of DERs (30 years), capture uncertainty in deferrable projects (both within and outside the planning horizon), and reflect a planning scenario using a no-DER forecast. To avoid parallel discussions between the Long Term Refinement Report and comments on the IOUs' methodology filings, which will follow a separate, Energy Division-led process, the WG acknowledges that discussion on an avoided transmission value for DERAC should take place in the Energy Division-led process, envisioned to start no earlier than January 2018.

Mirroring the delineation between these uses of LNBA by the Commission, the WG agreed that in general, discussion on the avoided transmission value could be parsed into 1) discussion related to how incremental DER solutions to identified needs may be considered in the transmission planning process (most related to the planning use case), and 2) discussion on transmission avoided cost most related to the cost-effectiveness use case.

In addition, discussions on the deferral use case are identified as useful, but addressed in parallel through other discussion forums, including CAISO-led discussions on the transmission access charge (TAC) and understanding the outcomes of PG&E's Oakland Clean Energy Initiative project in Oakland. In addition, there are many variables with regards to understanding how DERs may defer transmission projects (including, but not limited to, reliability standards, operational standards, cost recovery, development of integrated wires and DER solutions, and jurisdictional issues) that are out of scope for the LNBA. To that end, the WG identifies discussion items and issues for consideration to date, and agrees that the avoided transmission value for the deferral use case may be revisited at a later date. Further deliberation and comment and further deliberation on methodology for the cost-effectiveness use case are deferred to the separate Energy Division process overseeing the evaluation of the cost-effectiveness use case.

The discussion to-date of both the deferral use case and the cost-effectiveness use case are included here. Subgroup members have submitted written proposals detailing their proposed methodology for calculating an avoided transmission value. The written proposals from the utilities reflect the method proposed in Dec. 5 filings. The full proposals can be found in their individual filings. Non-IOU subgroup members' proposal are summarized in the report and can be found in full in Appendix B.

4.5.2 Avoided cost value of deferring planned projects (i.e. Deferral Use Case)

With regards to the deferral use case, the subgroup developed a better understanding of the California ISO transmission planning process, and discussed how the CAISO currently identifies alternative mitigation opportunities and considers preferred resources both in its forecasting and as incremental solutions to identified needs.

The ISO annual transmission planning process utilizes the California Energy Commission (CEC) energy and demand forecast produced as a part of the Integrated Energy Resource Plan (IEPR) in the planning process in accordance with the Commission's annual Planning Assumptions and Scenarios ruling. The CEC energy and demand managed forecast includes DER such as self-generation and Additional Achievable Energy Efficiency (AAEE). In the transmission planning process, the ISO uses the CEC mid-demand forecast with the mid-low level AAEE in local area planning and mid-mid-level AAEE for system planning as its base scenario analysis. This analysis is used to determine reliability needs on the transmission system and mitigation plans to address any identified reliability constraints on the system per the applicable reliability standards. As a part of the ISO transmission planning process, the mitigation that is considered to address the identified reliability constraint includes assessment of transmission alternatives as well as non-transmission alternatives that include preferred resources and DER beyond the levels already included in the CEC IEPR energy and demand forecast. The ISO transmission planning process is an open and transparent process per the ISO Federal Energy Regulatory Commission (FERC) tariff. Within the process, the ISO conducts the reliability analysis and posts the results of the reliability analysis on August 15 each year at which point parties can submit alternatives to mitigate identified reliability constraints in the ISO Request Window. The Request Window is open from August 15 to October 15. In addition, the ISO holds a stakeholder meeting in later part of September to present the reliability assessment results to stakeholders along with potential mitigation alternatives presented by either the ISO or the participating transmission owner (PTO). The ISO develops recommended mitigation plans in the ISO annual Transmission Plan. The ISO posts the draft annual Transmission Plan for stakeholder comment at the end of January and presents the final Transmission Plan for ISO Board of Governor approval in March. If the mitigation plans include transmission alternatives to "wires" solution as the recommended alternative, the ISO Board of Governors must approve these projects as required by the ISO tariff. However, if preferred resources are identified as the recommended mitigation plan, the ISO Board of Governors does not approve the preferred resources, but rather depends on the California Public Utilities Commission (CPUC) or other relevant local regulatory authority to authorize the procurement of the preferred resources. The ISO Board of Governors only approves transmission projects, not alternative mitigation procurement. In the Transmission Plan, the ISO recommends that the PTO serving the territory in which the reliability constraint occurs pursues the preferred resources through the appropriate state procurement processes.

The subgroup discussed and agreed that existing and ongoing conversations on consideration of preferred resources and alternative mitigation, through CAISO processes and ongoing utility procurement (notably, through PG&E's Oakland Clean Energy Initiative), are worthwhile and should continue. Accordingly, avoided transmission value on a deferral basis should continue to be studied and may be revisited for inclusion into the LNBA at a later date.

4.5.3 Avoided Transmission Value for DERAC Calculator (Cost-Effectiveness Use Case)

With regards to the cost-effectiveness use case, the joint IOUs submitted methodology proposals to the CPUC ED on December 5. Their proposals on an avoided transmission value are summarized below, and can be found in full in their individual filings.

Pacific Gas & Electric (PG&E) Proposal

PG&E states it is currently premature to make a specific proposal regarding development of a geographically differentiated transmission capacity avoided cost at this time, but is open to working with CAISO and other stakeholders to determine whether a geographically differentiated transmission capacity avoided cost is supported by data and consistent with CAISO and FERC guidance and rules. At this time, PG&E's preference is to look to the CAISO market data to determine if there is an observable differential locational value for the provision of transmission services and how that differential value is currently monetized before attempting to develop a shadow price proxy. If a locational transmission avoided cost is supported by the analysis, then development of "transmission factor (T-factor)" criteria (parallel to the D-factor method proposed for distribution avoided cost) that would be required for a DER program to show that is has the right place, right time, right availability and right certainty to capture the location specific transmission avoided cost under prevailing CAISO and FERC guidance and rules. In the meantime, the joint IOU proposal on for locational avoided generation capacity using Local Capacity Requirement data would capture benefits of reducing peak load in identified transmission-constrained areas.

Southern California Edison (SCE) Proposal

In SCE's 60 day filing for the DERAC use case, SCE described a methodology that estimates the transmission value. At a high level, the methodology divides SCE's territory into three categories: import regions, export/transfer regions, and ambiguous regions. These three categories correspond to a positive, negative, and zero transmission value. SCE proposed developing marginal transmission cost with the same methodology as in their GRC Phase 2 as the positive value and the inverse of MTC to as the negative value.

Regions

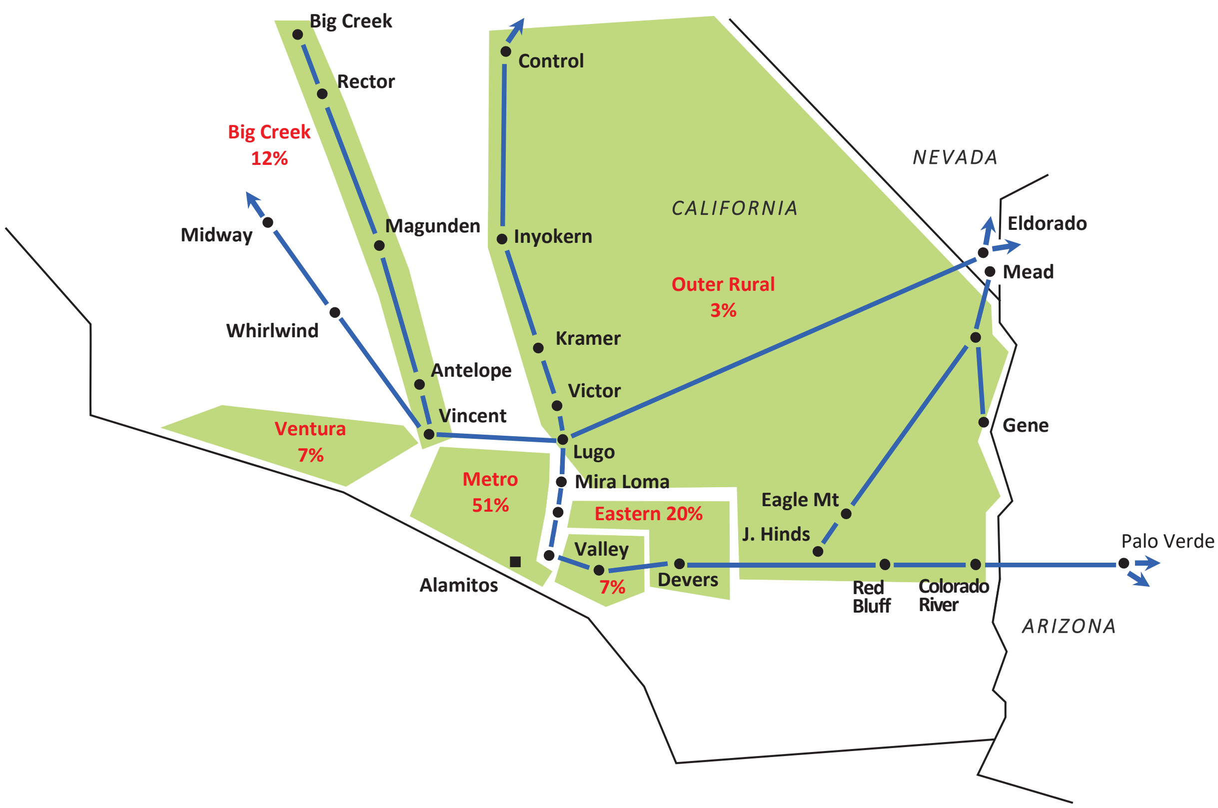
Import Regions (or load centers) are those regions characterized by substantial local load and limited local generation. The transmission system within these regions serves to import energy from other regions that have excess generation. Load growth in these regions may strain existing transmission resources, and continued load growth will eventually require upgrades to the transmission system. Within such regions, DERs that provide net load reductions are valuable: They reduce the forecasted load growth, and thus defer the upgrades to the transmission system. In SCE's territory, this region is limited to the Metro and Ventura regions. In these region, DERs may create transmission value by decreasing net load at peak times.

Export/Transfer Regions are those regions characterized by limited local load and extensive local generation. In these regions, the transmission system serves primarily to move energy to other regions that have greater load. In other words, the majority of the energy that flows across the transmission assets in these regions does not get consumed within the region; it instead flows onward to other regions. These regions are defined by having excess energy due to the surplus of generation. This fact is critical when considering the net load reduction provided by DERs: when even less energy is consumed within the region, a *greater* quantity of energy must flow out of the region to the load centers. Consequently, DERs deployed in these regions provide negative value if they decrease net load on peak: they increase need for future transmission upgrades to handle increased energy transfer from these regions to the load centers, and thus they increase the expected future customer costs. In SCE's territory, this region corresponds to the Outer Rural.

Ambiguous regions are defined by uncertainty in the mix of generation and peak load growth: The uncertainty is significant such that one cannot clearly assert whether the region is likely to be an import region or an export region. Indeed, within these regions, it is likely that some years the region will be a load import region, and some years the area will be an export/transfer region. Consequently, one cannot assert with any confidence that a net peak load reduction will relieve transmission constraints or exacerbate transmission such constraints. As a result, one cannot state with confidence whether DERs will add value or impose costs to the transmission system. In SCE, these regions are Big Creek, Valley, and Eastern.

The Regions are shown on the following *illustrative* graphic:

Figure 1: SCE Regions



Estimated Value

For Positive Value regions, SCE will define avoided cost based on the marginal transmission cost (MTC). MTC represents the opportunity cost of new capacity, in terms of $/kW-year. This cost represents the incremental cost of new transmission facilities related to peak load growth need. The actual value assignment will be based using an "escalating fraction" approach: The value begins at zero in early years, as there is no opportunity to defer capital in the early years. Then, the value increases as an increasing percentage of MTC, growing from 10% MTC in year 11 to 100% MTC in year 20 and all years beyond. The derivation of marginal costs will incorporate use of the Real Economic Carrying Cost (RECC) methodology, which calculates the present value of the one year deferral of capacity related capital investments.

For Negative Value Regions, SCE will define value to be the "inverse of MTC." The "inverse of the MTC" means taking the MTC value, but applying it in the negative rather than the positive. The same escalation schedule will apply. DER resources that reduce net load during peak periods will thus see a negative value. However, DERs that *increase* load during the peak period will see a positive value.

For Neutral Regions, the transmission value is defined to be zero in all years.

The table below summarizes the proposal and the application to SCE's regions.

Table 2: Summary of SCE Proposal By Region

Category	Regions Included	Value
Positive Value	Metro, Ventura	MTC (using RECC) based on escalating fraction approach: Years 1-10: Zero Years 11-20: Straight line escalation from 10% to 100% (10% increase each year) Years 21-30: 100%
Negative Value	Outer Rural	Inverse of MTC using RECC; same schedule as above
Neutral	Big Creek, Valley, Eastern	Zero in all years

San Diego Gas & Electric (SDG&E) proposal

SDG&E continued to emphasize the need to perform additional work/studies with the CAISO to develop a transmission level project assessment that can generate similar datasets to that of the distribution data that was produced in the LNBA for the IOU demonstration C/IDER pilots; the most important of which being location specific load reduction values that mitigate a given project need. Without more thorough understanding of the specific magnitudes and locations of load reductions needed to offset a transmission project SDG&E also believes it is premature to make a specific proposal regarding development of a geographically differentiated transmission capacity avoided cost. SDG&E remains adamant that for avoided transmission cost to be realized by ratepayers via DER(s), that the CAISO should be able solicit for and analyze DERs in being able to offset a specific grid need through the existing TPP process and be confident that any DER project alternative is consistent with all CAISO and FERC guidance and rules. Since CAISO is the ultimate owner of the TPP process it will be necessary for them to have the analytical tools to produce the needed datasets. SDG&E desires to support the CAISO as necessary to enable them to develop these tools to derive avoided cost values and to enhance the existing TPP process to more easily include DER alternatives.

California Independent System Operator (CAISO) Comments for Consideration

In addition to the IOUs' filed proposals, the subgroup discussed whether it was feasible for CAISO to similarly use a no-DER growth forecast. CAISO has additionally submitted the following comments for consideration regarding the cost-effectiveness use case:

As agreed between the ISO, CEC and CPUC, the transmission and resource planning use the CEC's IEPR managed forecast for energy and demand as the base scenario for all planning processes. Using the CEC IEPR forecast, the ISO annual transmission planning process assesses the reliability needs and develops mitigation plans with the forecast DER that are incorporated into the base scenario. The ISO does not conduct counterfactual analysis to assess the reliability needs or mitigation plans without the DER included in the CEC IEPR energy and demand forecast. This analysis would be overly burdensome and would require the ISO to develop mitigation plans to meet the requirements of the applicable reliability standards under the counterfactual scenario. The ISO does conduct sensitivity analyses that are incorporated into the annual study plan. The annual process allows for stakeholder comments in February of each annual planning process cycle. These sensitivities have included assessments of the reliability constraints that would occur if the AAEE in the managed forecast does not materialize; however mitigation plans are not developed for these conditions as they provide information only on potential reliability needs if the planned AAEE identified in the CEC IEPR forecast does not materialize as forecast. This information can be used to identify potential areas of targeting for AAEE or applicable other DER programs to ensure that the forecast load modifiers in the CEC IEPR energy and demand forecast are developed as planned. The ISO analysis does not provide valuation of mitigation for these as the ISO does not develop mitigation plans for these sensitivity assessments as the AAEE is assumed to be a part of the managed forecast as agreed to between the CEC, CPUC and ISO.

Some members of the subgroup have developed the following written proposals for consideration; they are included in full in the Appendix and summarized below:

The Utility Reform Network (TURN) proposal

The Utility Reform Network (TURN) submits this following proposal, and believes that the proposal is equally applicable to the use of DERs for transmission deferral and to the cost-effectiveness use case.

TURN has identified process recommendations and outlined an avoided cots methodology for identified planned projects. TURN believes additional fact-finding is necessary before any meaningful value is incorporated into the DERAC tool and a Commission decision is made. Thus, TURN first recommends that the CPUC coordinate with CAISO to develop a process that would allow for the use of relevant CAISO data from the transmission planning process to address gaps in data. In addition to this fact-finding process, TURN recommends that the CPUC coordinate explicitly with the CAISO to ensure that any avoided cost value in the DERAC reflects a reality in which the CAISO actually defers transmission projects through procurement of DERs, better forecasting, and other mechanisms.

TURN's avoided cost methodology to address deferring planned projects is based on the following four guiding principles: 1) all values must correspond to revenue requirement reductions for the IOUs and CAISO. Otherwise, ratepayers may pay twice for the same project; 2) Forecast impacts from DERs that are intended to reduce transmission investments must flow through appropriate CPUC or CEC forecasts to impact CAISO TPP; Values must be determined in an analytical fashion and be based in known fact; and 4) Estimated avoided cost values should be for evaluation purposes only; actual payments to DERs should be based on competitive solicitations so that ratepayers have the opportunity to save money in comparison with business-as-usual.

The deferral value for planned projects should use the CAISO TPP as a starting point for identified planned projects, and be updated annually. The deferral value should be based on:

- Deferral values for DERs related to transmission projects planned due to load growth should be based on an understanding of the peak hourly demand of the project combined with expected peak hourly reduction from a given DER. For example, a resource that does not contribute to reducing peak load would not be awarded value for a particular project.
- Only projects identified by CAISO as potentially deferrable by DERs (generically any "non-wires" or "preferred resource" alternative) should be included in the avoided cost value. Projects should be removed if CAISO determines through the TPP that a non-wires alternative is not feasible. This includes the following two categories of projects:
    1) Transmission projects identified by the CAISO as *potentially* having a non-wires alternative;
    2) Transmission projects for which alternative proposals to deploy DERs are *received* by CAISO from an outside entity (PTO, DER provider, etc.).
- Deferral values should be locational in nature wherever possible, applying to an entire DLAP, sub-lap, or other area of granularity where a project is proposed to be built. In the future, the Commission should base locational values on load-flow models to determine where DERs have the most impact on reducing peak load for a given constraint. Existing load-flow exercises conducted in the TPP or for local capacity determinations may be leveraged to this end.
- A price cap on Local Reliability Areas marginal transmission costs could be set equal to the costs of generation alternatives, such as market prices for local Resource Adequacy capacity in each area or the CAISO's Capacity Procurement Mechanism price. A computation of the deferral value of new generation investment could also be applied as a price cap to ensure reasonable deferral value results.
- Computation of deferral values of avoided transmission investments should be computed using the "NERA Method" which the utilities now use to compute marginal transmission and distribution costs for rate design purposes

Solar Energy Industry Association (SEIA) proposal

The Solar Energy Industry Association (SEIA) proposed to develop the counterfactual, long-run transmission costs avoided by DERs by first calculating a long-term system avoided cost value that can be used over the full 25-year lifetime of DER, then developing a means to increase locational granularity. With regards to the system-level value, this should reflect long-run avoided bulk transmission costs for each of the IOU service territories. This should be the system value for use in the DERAC calculator and also be the Commission's priority. SEIA recommends that this calculation use the National Economic

Research Associates' (NERA) regression methodology that the utilities often employ to calculate marginal sub-transmission and distribution costs. Additional input, such as including more data from the IOUs, will allow for further methodology refinement. Alternatively, the avoided transmission cost could be divided into two components: 1) the marginal cost per kW of peak demand for all transmission investments related to load growth, reliability, or economics and (2) the marginal cost per kWh of transmission built to access RPS resources. The first component would use the NERA regression method discussed above, but limited to transmission investments related to load growth, reliability, or economics as a function of planned peak capacity. The second component would be a separate calculation of the marginal cost of RPS-related transmission, with kilowatt-hours as the driver because the RPS goal is based on kWh sales. In this calculation, renewable generation from DERs would be assumed to displace RPS generation on a kWh-for-kWh basis, because both contribute equally to meeting the state's long-term carbon reduction goals. DERs that simply reduce loads (such as energy efficiency measures) would be assumed to avoid marginal RPS transmission costs by the kWh saved times the applicable RPS percentage-of-sales requirement.

To develop more granular, locational avoided costs, SEIA recommends that all stakeholders continue to work to refine the CAISO's transmission planning process to support consideration of DERs as a non-wires alternative for specific local areas (for example, the transmission investments developed to resolve capacity deficits in the Western LA Basin from SONGS retirement identified a cost benchmark for alternative resources).

SEIA also takes the position that all transmission costs should assume to be deferrable by DERs, and presents rationale why DERs can defer all four primary drivers of transmission investments (to serve peak loads, reliability, economic, and policy-driven investments). Further, given the networked nature of the transmission system, projects built principally to meet one need can provide secondary benefits, necessitating that all transmission investments need to be included when calculating marginal transmission costs.

Clean Coalition (CC) Proposal

Clean Coalition agrees with the SEIA proposal in that it agrees that a system-wide marginal cost of transmission should serve as a starting point, building upon CAISO data to improve locational value. As a starting point, Clean Coalition proposes using the per-MWh valuation of transmission revenue requirement (TRR) reduction achieved by DER, consistent with the CAISO transmission access charge. Clean Coalition's Transmission Impact Analysis Model that calculates this value, reflecting the impact profile of each DER category on both total load and peak load. Clean Coalition also supports locational variation factors to be applied to the default marginal cost value based on forecast regional transmissions needs if DER growth did not occur.

Clean Coalition additionally echoes SEIA in that DERs can reduce the need for transmission investments for peak capacity, reliability, economic, and policy purposes.

5. Group II topics

5.1 Incorporating an uncertainty metric

The LNBA WG had previously identified the incorporation of an uncertainty metric as a non-consensus topic. The WG has considered the "uncertainty metric" with regards to load forecasting, to provide an indication of the likelihood that the forecasted need is likely to occur. For example, a project based on a forecasted need five years out is less certain that a projected based on a forecast two years out. The LNBA tool does not currently incorporate forecast uncertainty. The WG discussed the development of the uncertainty metric within the LNBA use cases, including both how the value could be included in the LNBA tool as well as how it may be represented on the LNBA heat map.

With regards to the deferral framework use case, the WG is in consensus that the uncertainty/certainty metric should be used as one of the prioritization variables within the Distribution Investment Deferral Framework (DIDF) to select deferrable projects to move to RFO for DER procurement and solicitation, to screen out non-desirable candidates for deferral. The WG recognizes that determinations on this measure will be made as part of a pending Decision on DRP Track 3 issues.

The WG discussed that the uncertainty/certainty metric will not be used to screen out projects that would otherwise be included in the LNBA – this screening has been identified through the IDER Decision on competitive solicitation, and will be more fully developed in a pending decision on DRP Track 3 issues, whereby projects that pass technical screens to identify grid services and the timing screen are included as projects within the LNBA tool.

The WG discussed that the uncertainty/certainty metric is a qualitative screen reflecting the timing of the distribution need and load growth or generation project driving that need. Distribution needs closer to present day are deemed more certain and of higher priority. Another way to assess certainty is the presence of a formal interconnection request. The IOUs will use the certainty/uncertainty metric as one assessment of distribution need, to prioritize potentially deferrable projects to be included within the RFO process.

The WG discussed that, pending a DRP Track 3 Decision on the deferral framework, this qualitative metric can be reflected in the LNBA maps through an additional layer indicating certainty as "low", "medium", or "high".

With regards to the cost-effectiveness use case defined by the Track 1 Decision on ICA and LNBA, the Decision directs the IOUs to calculate the probability of unanticipated T&D projects up to a 30-year window and the necessity to determine grid needs and planned projects absent of the anticipated "autonomous growth" of DERs. The methodology for this use case will be included in the IOU-filed proposals due December 6. The WG engaged in discussion regarding how the uncertainty metric may be included within the LNBA methodology, but agreed that further discussion regarding its incorporation should be conducted through the ED-led workshops envisioned in the Decision on the IOU-filed methodologies.

5.2 Incorporation of Growth Scenarios

The IOUs used two growth scenarios in Demo B: a planning scenario (representing the forecast used for distribution planning) and a "very high" scenario (representing full implementation of ambitious policy objectives and resulting high-DER adoption). The WG discussed whether the LNBA should use multiple growth scenarios or a single planning scenario. This topic additionally requires coordination with the DER Growth Scenarios developing under DRP Track 3, Sub-track 1. Currently, IOU distribution planning only uses a single forecast, and existing tools and resources only support the use of one forecast. Conducting multiple scenarios requires additional IOU resources to develop the requisite enhancements to planning tools.

The WG agrees that, for the time being, the LNBA should remain as consistent with growth scenarios assumptions made in the distribution planning process as possible. The WG may consider appropriate refinements to the LNBA tool after the Track 3 Sub-track 1 on growth scenarios is resolved. The WG also recognizes that the September Decision on Track 1 issues (D.17-09-026) establishes a process to discuss the implementation of an alternative DER growth scenario "to calculate Distribution Planning Area-level avoided Transmission & Distribution values for input into the Distributed Energy Resources Avoided Cost Calculator[9] to better inform decisions on programs and tariffs."

6. Group III topics

6.1 Explore asset life extension/reduction value provided by DERs

Asset life extension or reduction is identified in the Track 1 Decision as a long-term LNBA refinement which could provide possible DER benefits outside of capital investment deferral. Asset life extension or reduction refers to how DERs may impact or reduce the likelihood of equipment failure. This is separate from routine operations and maintenance tasks and distribution capacity upgrade deferrals. Distribution assets are removed from service due to 1) failure (e.g., manufacturing defects, environmental factors, specific incidents, wear and tear, and thermal degradation), 2) obsolescence (when the old design is no longer considered safe or functional for current needs), and 3) redeployment (when transformers that are not at end-of-life which are replaced during a capacity upgrader are kept in stock and redeployed). The WG identified, discussed, and agreed that DERs may impact the life of distribution assets removed from service only for a subset of failures (wear and tear, thermal degradation). Further, while the physical bases for these two modes of failure are relatively well understood, the specific DER impacts are not fully characterized today.

The IOUs' proposal, found in Appendix B, summarizes current research by the California Solar Initiative, IEEE, UC Berkeley, EPRI, and others on DERs' impact on asset life. The current research suggests that DER effects on asset life are likely small and are not consistently positive (i.e. sometimes DER increase

[9] D.17-09-026, p. 62.

asset life) or negative (i.e. sometimes DER decrease asset life). In addition, the IOUs list a number of key questions that remain when trying to relate a given DER profile to the wear and tear or thermal degradation of a distribution device and then relating those impacts to actual avoided cost. The Joint IOUs' October presentation to the WG[10] provides an overview of some of these key questions, which include:

- What assets fail due to thermal degradation or wear and tear – both type and quantity/percent? (In general, IOUs seek to avoid operating equipment at loading levels which might reduce expected life)
- How do different DER profiles, combined with different underlying load profiles, affect transformer temperatures?
- How do different DER profiles, combined with different underlying load profiles, affect number of tap changer or switch operations?
- How significant is the benefit or cost of an increase or decrease in distribution asset life?

The IOUs noted their outreach to seek available research, including to EPRI, and evaluating ongoing studies at SCE. At this time, the IOUs believe that, with the limited state of knowledge in this area, it is not appropriate to prospectively include this component as either a cost or a benefit.

The WG agrees on how asset life impacts of DERs should be calculated, using the methodology outlined in the IOU's proposal. The WG does not agree as to whether the value should be incorporated into the LNBA tool at this time given existing research.

The IOUs propose that equipment life extension should not be incorporated into LNBA currently, due to lack of potential value relative to the cost to achieve value stream certainty. The IOUs would prefer to not include any such value until some future study more clearly confirms how one can accurately calculate and assign this value stream.

In contrast, SEIA argues that this timing would mean the LNBA will not include this value during the time horizon of the DER Action Plan when these values are expected to be determined. SEIA believes there is not much work to take the IOUs methodology and translate it into value. SEIA argues that the utilities have not only provided a conceptual model for understanding DER-enabled equipment life extension, but have also established a mathematical relationship between thermal load and equipment degradation. SEIA believes that what is needed is a means of translating the relevant revenue requirement which can provide a present value revenue requirement for extended equipment life. SEIA proposes that the Commission should direct the IOUs to use their calculations to derive this revenue requirement and subsequently a value for inclusion in the LNBA.

In determining next steps, it would be helpful for the Commission to further explore:

[10] https://drpwg.org/wp-content/uploads/2016/07/10.16-and-10.17-ICA-and-LNBA-deck-final.pdf

- Based on current understanding of DER impacts and the existing scope of research, is there sufficient information to incorporate an initial value for asset life extension into the LNBA or should the issue be revisited at a later date? If the later, what is an appropriate timeline?

6.2 Conservation voltage reduction (CVR)

The LNBA WG discussed a stakeholder proposal jointly submitted by SEIA and Tesla to create a locational value for CVR benefits that can be realized through utilities' existing CVR schemes when DERs are available at the low-voltage customers on a distribution circuit, typically at the end of a circuit. This proposal states that distributed PV combined with smart inverters provide CVR benefits, primarily at the secondary level, that should be included as a value within LNBA.

Existing utility CVR programs address voltage delivery oversupply by flattening distribution voltage profiles while meeting Rule 2 standards to lower voltages at customer points of service. CVR programs are often implemented via changing the load tap changer (voltage regulator) settings on a substation bank and its downstream circuits as well as distribution capacitor settings. Distributed PV and smart inverters may enable savings from utility CVR programs by raising end of line service voltage. When the end of line voltages are raised the utility can modify the settings on its larger regulating devices to more aggressively lower voltages at the feeder head resulting in lower service voltages for the majority of circuit customers. Distributed PV and energy storage with smart inverters can increase or decrease the voltage at any individual customer location, these resources could potentially be used to more granularly control secondary service voltages.

Tesla and SEIA propose to calculate the CVR benefit as a locational value for solar and smart inverter deployment on areas of distribution circuits with the lowest voltage. This value could be represented in the LNBA/ICA maps of the utilities' distribution grids. In their full written proposal, Tesla and SEIA provide formulas to compute the maximum percentage voltage reduction made possible on a particular circuit by raising the voltage of the lowest-voltage secondary lines, assuming optimal utility voltage control. This voltage reduction could then be converted to MWh of energy and MW of capacity reduction induced on the circuit – full details of this methodology are included in the written proposal (see Appendix B). If utilities do not have sufficient information on all of their secondary lines to develop a locationally-specific CVR value, SEIA and Tesla propose an alternative method where averaged CVR value (based on average contribution of solar PV and smart inverters to existing utility CVR programs) is integrated into the LNBA and included in instances where CVR is one of the benefits provided by DERs – for example, in the evaluation of a voltage management tariff developed in the Integrated Distributed Energy Resources proceeding.

The LNBA WG is in non-consensus with regards to the proposed SEIA/Tesla methodology, with the Joint IOUs and TURN both submitting comments. The IOUs state that it is inappropriate to use a system-wide value for CVR when the benefit is contingent upon load/feeder characteristics, locations of smart inverters and quantities, utility voltage regulating device availability, level of utility device control, and existing device settings. The IOUs state they currently do not have the needed control capabilities to manage voltage-regulating equipment such that CVR benefits could be increased using distributed smart inverters, and calculating a prospective value is not appropriate. Further, adopting any CVR scheme with smart inverters requires all customers served by a substation to have smart inverters that participate in that scheme. Every smart inverter and the substation bus will need to communicate with each other to understand how there are operating to keep voltage within Rule 2 limits. Finally, the IOUs state that the proposal improperly suggests calculating CVR benefits that are based on customer bill savings rather than utility avoided cost (as specific customers operate more efficiently through optimized voltage levels in CVR, they individually realize a financial benefit of paying for less consumption) and refers to a value for smart inverters providing CVR that is mostly attributable to a voltage optimization scheme rather than to the smart inverters themselves. None of the IOUs has comprehensively implemented this voltage optimization scheme which is both necessary to enable smart inverters' ability to provide CVR and also would be responsible for the vast majority of energy savings that can be realized via CVR. Attributing CVR value to an individual or small group of smart inverters is premature, and does not represent real savings until a fleet or group of smart inverters communicate with utilities and each other to optimize voltage and actually achieve benefits.

TURN asserts any avoided cost or benefit included in the tool must be captured by all ratepayers and the inclusion of CVR within the LNBA tool does not meet this principle. They reason these benefits are based on active utility involvement that is not currently performed – currently, these benefits are only theoretical. TURN asks developers to continue working with utilities to implement and test CVR programs to demonstrate an actual avoided cost value. Attributing CVR value to an individual or small group smart inverters is premature and does not represent real savings until a fleet or group of smart inverters communicate with utilities and each other to optimize voltage and actually achieve benefits.

SEIA, TURN, and the Joint IOUs have identified distinct recommendations for next steps.

The Joint IOUs recommend that, given that it is currently very difficult to calculate the actual recorded energy savings from the reduction in voltage, that they continue ongoing research on the extent of sensing and communication equipment required to implement CVR with smart inverters before determining how to incorporate CVR energy savings as a value stream within the LNBA.

TURN recommends that the Joint IOUS work with DER developers to implement and test CVR programs before an actual avoided cost value methodology is incorporated into the LNBA tool.

SEIA recommends that the Commission adopt a calculation for CVR using the methodologies outlined in Tesla and SEIA's memo to the working group[11]. SEIA agrees with TURN that the benefit of CVR should not be ascribed to programs where smart-inverter-enabled CVR is not going to be operationalized by the utility. However, since the Commission is expected to evaluate means of sourcing locational distribution grid services, including voltage management, in the Integrated Distributed Energy Resources (IDER) proceeding, it is critical that the Commission have a value in the LNBA for determining compensation for such a service or, at the very least, evaluating the cost effectiveness of a tariff that includes such services. As California moves towards a greater reliance on DERs to provide distribution grid services, the LNBA must be able to not only support evaluating current benefits but also services that are

[11] https://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-4-Tesla_SEIA_Conservation_Voltage_Reduction-22AUG17.docx

proposed to be developed in open proceedings so that the valuation methods for such services are available as they are developed.

In determining next steps, the Commission should consider:

- Does either the primary or alternative methodology proposal from SEIA provide a value that reflects actual utility avoided cost?
- Do the needed control capabilities exist to manage and enable distributed smart inverters? What is the current extent or future capabilities of utilities to implement CVR? Is there additional research needed?

6.3 Situational awareness

The concept of a DER distribution service related to data for grid visibility and situational awareness emerged during the IDER CSF WG discussions; however, no consensus on the definition or viability of this service was reached. The June 7 ACR states that "value of data-as-service for situational intelligence is likely hard to quantify on avoided or marginal cost basis, and is driven to some degree by Commission policy on the use of DER data for grid operations and/or planning."

The WG is in non-consensus with regards to whether a value for situational awareness is appropriate for the LNBA, how it may be calculated, and what are appropriate next steps. In WG discussions, two proposals for defining the benefit and quantifying the value of situational awareness were discussed, one by the Joint IOUs and one by SEIA. These discussions helped expand understanding of this DER service, primarily through exploration of what grid data may be provided by DERs, how these data could assist IOUs, and whether this can or should be quantified within the LNBA tool.

The joint IOUs proposed to define situational awareness as the provision to the utility distribution company (UDC) of grid information which is collected using DERs and which meets the following conditions: 1) the information meets a specified grid need for which the IOUs are planning an investment, 2) the information meets the data requirements as specified by the IOU (e.g. for data type, detail, frequency, location, voltage level, security, completeness, etc.), and 3) the information is not already required to be provided by the DER (e.g. as a requirement to interconnect). The value of this service would be equal to the avoided revenue requirement of deferring the otherwise-needed capital investment calculated using the Real Economic Carrying Charge (RECC) method, or equal to the avoided RRQ associated with an expense that would otherwise be incurred to meet the same need.

The SEIA proposal outlines the type of grid information that DERs can provide. This includes voltage, frequency, outage information and loading information. This information can be used to 1) calculate gross load and better understand load profiles; 2) ID faults for faster service restoration; 3) provide data at a greater frequency than through existing communications infrastructure; and 4) provide nodal level data on power quality conditions. SEIA proposes the value of this service as the avoided cost of other equipment needed to provide the utilities with situational awareness that would otherwise need to be deployed in the absence of DER equipment providing these services, including: avoided cost of additional bandwidth needed on wireless communication networks to backhaul data; avoided cost of additional metering for on-site generation to calculate gross load; reduced truck rolls from improved fault location; and avoided cost of line sensors. These investment costs can be estimated from utilities' GRCs and Advanced Metering Infrastructure (AMI) Applications.

SEIA proposes that the Commission use data from utility General Rate Cases, AMI and Smart Grid applications to develop a general estimate of the value of situational awareness on utility distribution systems to be used in the Locational Net Benefit Analysis. As SEIA has noted on Conservation Voltage Reduction, a value must be calculated and available in the LNBA as a tool for valuing distribution grid services which have not yet been developed but are reasonable to expect may be developed as part of the Integrated Distributed Energy Resources proceeding or other CPUC proceedings; SEIA does not believe that resources should be assigned this value unless it is being provided. This information could be used to provide a general assessment or approximation of the cost of providing situational awareness.

SEIA argues that, recognizing that DER providers should not be assigned value for services that the utilities are already obtaining using previously deployed equipment, a forward looking value for situational awareness should be ascertained using the cost of proposals to deploy infrastructure for the purpose of providing situational awareness that are pending before the Commission but not yet approved.

The Joint IOUs argue that the services identified by SEIA are insufficient in addressing IOUs' situational awareness needs, and do not result in a clear avoided cost that may be included in the LNBA. With regards to calculating gross loads, the IOUs note that DERs do not provide load information, only generation output information. Further, DER generation data could only be obtained from a subset of DERs with sufficiently reliable communication. With regards to fault identification, the IOUs note that DERs can only provide data that is obtained by the IOUs today via AMI data, and that the DER cannot actually locate the faulted circuit segment, particularly for outages spanning multiple circuits – thus, DERs cannot provide the necessary precise fault information currently provided by line sensors, SCADA data, and fault indicators. DERs can display outage information for the specific set of customers for which a DER installation is located, which IOUs have today, but not locate the actual location of a fault or downed wire causing those customers to be out of power. Therefore, they will be unable to reduce outage times or replace the need for fault detecting devices, such as fault indicators, or sectionalizing devices, such as switches. With regards to power quality, the IOUs note that DERs cannot provide voltage information on the primary distribution system, while utility AMI systems can. DERs provide voltage information only at the metered locations installed on the secondary system beyond the distribution service transformer. Further, reporting frequency from AMI systems can be increased if necessary and justified (currently they report once a day). Finally, the IOUs note that while real-time generation output information is useful, this particular localized real-time outage or power quality information provided by DERs is not useful, as it's specific only to customers with DER installed at their locations. IOUs have this information today and thus it should not be valued as a benefit of DERs within the LNBA.

Within written comments, WG members engaged in discussion on avoided costs from data collection, additional hidden costs of DERs providing grid data, minimum interconnection requirements for smart inverter-based DERs, and whether DERs should instead market data services on a competitive basis to the IOUs rather than being assessed as a value within LNBA.

In determining next steps, it would be helpful for the Commission to further explore:

- What additional information is needed to verify claims with regards to whether DER can sufficiently provide situational awareness services?

6.4 Non-capacity related reliability benefits

DERs may provide value in providing increased reliability via outage frequency reduction. In Demo B, non-capacity related reliability projects were identified as either deferrable or non-deferrable. In Demo B, deferrable reliability and resiliency projects were identified as back-tie and microgrid projects, respectively, while non-deferrable projects were identified as fault-related projects and standards violation projects. The WG discussed whether additional projects outside of projects providing back-tie capacity and microgrids services produce reliability benefits that should be captured within the LNBA tool.

The WG is in consensus with regards to the characterization of non-capacity reliability projects to include: 1) detecting faults on the grid (e.g., circuit breakers, automatic reclosers), 2) locating faults on the grid (e.g., sensing equipment); 3) sectionalizing circuits to minimize the impacts of faults (e.g., switches); and 4) fixing standards violations (e.g., reconfigure underground structure or distribution pole).

The WG is in non-consensus with regards to defining the additional reliability benefits that should be valued within LNBA and how to appropriately account for their value. Among the identified project types, the WG agrees that DERs cannot address standard violations., meaning the replacement of defective equipment. However, the WG is in non-consensus over whether DERs can provide the same reliability improvements that traditional utility investments could provide, and how they should be appropriately valued.

The IOUs' proposal identifies how DERs may provide some of these grid services but cannot fully replace or defer the need for these investments. While circuit breakers and automatic reclosers both detect faults and de-energize equipment for public safety, DERs cannot de-energize circuits and therefore cannot replace traditional breakers and reclosers. Switches on a circuit can isolate and de-energize a portion of a circuit, and transfer customers from one circuit to a neighboring circuit, while DERs cannot. Further, DERs cannot defer or replace fault indicators as they do not provide specific locational information to identify where the issue lies on the circuit segment. Finally, for utilities to truly avoid the need for reliability-driven grid modernization investments, customers would need to each install their own backup generation to maintain service during an outage scenario, which is less cost-effective than utility-driven investment – and in this situation, utilities would still need to invest in equipment to identify faults and restore service, to support customers coming off backup generation. Finally, Rule 21

SIWG Phase 3 requires information capabilities for all smart inverters. With Phase 2 Communications available, the IOUs should be able to get inverter production data.

SEIA argues that the utilities' characterization of what providing improved reliability entails does not reflect how DERs could provide a comparable or superior alternative for systemic reliability projects at lower costs than proposed by the utilities. The SEIA proposal argues that only considering back-tie projects and microgrid services provides a narrow valuation of DERs, and does not account for their ability to reduce customer outages. DERs should not be compared to traditional equipment on a one-on-one basis (e.g., comparing a solar-plus-storage system against a fault indicator or switch) given their different functionality; indeed, one of the benefits of DERs is that some can provide multiple services and perform numerous functions whereas switches, fault indicators, and other distribution grid equipment can only perform one limited function. However, it is reasonable to consider the ability of these resources to offset costs that might otherwise be addressed through utility grid modernization investments for improved reliability. SEIA proposes two possible methods to quantify this value. The first is to consider the value of lost load to the utility customers who would otherwise be subject to power outages.; as SEIA notes in their memo on this topic[12], this is how utilities in California and nationally justify the reasonableness of their grid modernization proposals. The second is to consider utility investments in infrastructure that have been approved or proposed in GRCs for the purpose of improving reliability and resiliency. SEIA reasons that it is likely more appropriate to use the latter method and pull data from GRCs to determine a standard cost to reduce service disruption or restoration of service. This value could be made location-specific by accounting for location-specific measures of reliability.

In making a Decision, it would be helpful for the Commission to consider:

- How should non-capacity related reliability projects be defined?
- Do the proposed methodologies' calculated added benefit reflect an avoided cost to ratepayers and properly account for the value that the DER provides?

6.5 Valuing unplanned grid needs within and beyond 10 years

The WG discussed how unplanned grid needs may be defined, both within a 10-year planning horizon and beyond 10 years. Valuing unplanned grid needs and providing a long-term value for DERs was discussed both in the context of modifying the existing LNBA tool as well as in the context of the IOU methodology to serve the cost-effectiveness use case. The WG defers all conversation with regards to the cost-effectiveness use case to the separate process to be established by the CPUC Energy Division. However, some discussion points prior to the September Decision to date are noted in the written proposals, written comments, and meeting notes from this WG process.

With regards to unplanned grid needs within the planning horizon that can be captured within the existing LNBA tool, the WG is in non-consensus on how unplanned needs should be defined.

[12] https://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-14-Non-Capacity-Reliability_SEIA.docx

The Joint IOUs propose that unplanned grid needs should be defined as projects that are required in very short timeframes (2 years or less), accommodating unforeseen load growth that drives load above and beyond an acceptable threshold for a given distribution substation/circuit. Unforeseen projects that arise within this timeframe are primarily derived from large, spot capacity needs (E.g., a large casino or development), that will grow the load so rapidly that an area's existing excess capacity will be completely utilized and/or exceeded. These needs, due to their timing and size, are unlikely to be deferrable by DERs. This is in contrast to the vast majority of projects which are developed under normal load growth conditions and are planned for implementation when the capacity of a distribution area begins to be limited. To reduce instances of projects arising in a timeframe that does not allow DERs ample opportunity to defer them and to be included in the LNBA heat maps, the IOUs propose to continue their work in refining the forecasting process and work to identify capacity projects further in advance of forecasted need. Further, the IOUs note that Demo C and projects through IDER provide an opportunity to potentially shorten the presumed window of DER implementation, giving DERs more opportunity to be considered for deferral of any unplanned grid needs. Going forward, the IOUs propose that, if the Commission finds it material, that they consider assessing the number of unplanned projects that may arise and amount spent on unplanned capacity investments to better understand the potentially opportunity and likelihood of DERs deferring unplanned grid investments. However, the IOUs do not think it is appropriate to generically apply a value to DERs at any one location for deferring unplanned grid investments, as this value in most locations will never be realized as actual avoided ratepayer cost.

Non-IOU stakeholders are not in consensus with the IOUs' characterization, and have raised concerns that projects that are loosely identified in the utilities' long range plans but are not clearly identified as specific projects with anticipated construction dates could not enter the solicitation process but would still benefit from incremental DER adoption. DERs could delay the timing of when a project progresses from a general concern to a specific planned project. This benefit could continue for years and even lead to distribution system concerns being removed from long range plans altogether without having developed into clearly defined projects with anticipated construction dates. DERs could also create additional flexibility for the IOUs with regards to engineering and construction resources for projects with anticipated completion dates that become less urgent without specific contracts for non-wires alternatives. Non-IOU stakeholders note that these benefits should be clearly reflected in the IOUs' methodology proposals to meet the cost-effectiveness use case.

Further, the non-IOU stakeholders note that the definition of unplanned needs for the deferral use case, while it may apply to large spot capacity projects, may not apply to voltage-related projects. The WG discussed that, under existing planning and DER sourcing approaches, it is difficult to identify voltage projects that fit a specific targeted deferral. Voltage-only upgrades are fairly inexpensive compared to capacity projects, so utilities use a blanket budget rather than an identified line item budget to account for voltage upgrade needs on a system wide basis. Further, the IOUs note that any inverter-based, voltage regulation-related projects would require sensors, communication, and IT systems which currently do not exist.

With regards to unplanned grid needs outside of the 10-year planning horizon, the WG is in non-consensus on how this should be valued. The WG sees that issue is more germane to the cost-effectiveness use case than the deferral use case, and defers discussion with regards to the cost-effectiveness use case to the separate Energy Division-led process on the third LNBA use case.

7. Topics not covered

The July 7 ACR identified four Group III topics as: “value proposition is speculative and potentially low; Working Group should only address these issues if time permits.” Based on feedback from participants about their priority topics to address given time limitations, the WG did not address the following two topics: 1) benefits of DERs reducing the frequency/scope of maintenance projects; and 2) benefits of DER penetration allowing for downsized replacement equipment.

Appendix A

Table 3: Summary of LNBA Working Group Meetings and Meeting Documents

July 7	Webinar recording Slide deck High level project plan proposal Meeting notes Participant list
August 15	Webinar recording Slide deck Participant list
September 19	Webinar recording Slide deck Participant list
October 16	Webinar recording Slide deck Participant list
November 13	Webinar recording Slide deck Participant list
December 14	Slide deck Participant list

Table 4: Summary of LNBA Avoided Transmission Subgroup Meetings

July 19	Webinar recording Slide deck participant list Meeting notes Circulated links and documents: • E3 avoided costs (2016 interim update) • PG&E's 2017 GRC Phase 2 testimony
August 2	meeting notes (draft) participant list webinar recording SEIA Avoided CAISO Transmission Presentation to DRP Working Group 2AUG17 Circulated links and documents: • CEC San Joaquin DER study (2016)
August 16	meeting notes (draft) webinar recording participant list slide deck
August 30	webinar recording participant list

	meeting notes (draft)
September 13	Webinar recording Draft Statements V1 (edits: Clean Coalition, Joint IOUs, TURN) Draft Statements V2 (edits: Clean Coalition, SEIA, E3, CAISO) Draft Statements V3
September 29	webinar recording slide deck
October 16	Slide deck Participant list
November 30	Slide deck

Table 5: Summary of Written Proposals and Written Comments

All proposals may additionally be found online at: http://drpwg.org/sample-page/drp.

Topic	**ACR or Working Group Report Item**	**Written proposals**	**Written comments**
Method of evaluating the effect on avoided cost of DER working "in concert" in the same electrical footprint of a substation/improve heatmap and spreadsheet tool by including options to automatically populate DER generation profile input	Group 1: ACR Item D/WG Report Item 2.ii	Joint IOUs	
Incorporate additional locational granularity into Energy, Capacity, and Line Losses system-level avoided cost values	Group I: WG Report Item 4	*Energy:* Joint IOUs initial proposal Joint IOUs revised proposal	
		Capacity: Joint IOUs SEIA	
		Line losses: Joint IOUs initial proposal Joint IOUs revised proposal	Clean Coalition
Form technical subgroup in LT refinements to develop methodologies for non-zero location-specific transmission costs (requires coordination/ co-facilitation with CAISO)	Group I: WG Report Item 5		Deferred to ED Process

Improve heatmap and spreadsheet tool by allowing hourly VAR profiles to be input in order to capture DERs' ability to inject or absorb reactive power	Group I: WG Report Item 2.iii and ACR Item B*[13]	Joint IOUs	
Incorporate a (forecasting) uncertainty metric in LNBA tool for planned deferrable projects	Group 2: WG Report Item 7	Joint IOUs	
Only use base DER growth scenario, not high growth scenario – requires coordination with DER growth scenarios under development in DRP Track 3 Sub-track 1	Group II: WG Report Item 11	Joint IOUs	
Methods for evaluating location-specific benefits over a long-term horizon that matches with the offer duration of the DER project; likelihood of an unplanned grid need emerging in a given location; locational value of DERs beyond 10 years	Group III: ACR Item A, WG Report Item 8 and Item 9	No formal proposal was submitted; the Joint IOUs provided initial thoughts during the October WG meeting via presentation slides and WG engaged in additional discussion during the November WG meeting	CALSEIA
Explore asset life extension/reduction value provided by DERs	Group III: WG Report Item 12	Joint IOUs	
Smart inverter capabilities: conservation voltage reduction (CVR)	Group III	SEIA and Tesla	Joint IOUs, TURN
Explore possible value of situational awareness or intelligence (*likely hard to quantify on avoided or marginal cost basis, and is driven to some degree by Commission planning on use of DER data for grid operations and/or planning)*	Group III: WG Item 13	Joint IOUs SEIA and Tesla	Joint IOUs SEIA (provided in tandem with SEIA written proposal)

[13] The WG discussed and agreed that Item 2.iii (hourly VAR profiles) and Item B (smart inverter capabilities) could be merged with Item B (smart inverters) as a Group I priority topic, and that additional smart inverter topics (conservation voltage reduction, situational awareness) would be discussed as Group III topics

Include benefits of increased reliability (non-capacity related) provided by DERs	Group III: WG Report Item 14	[SEIA](#) [Joint IOUs](#)	[Joint IOUs](#) SEIA (provided in tandem with SEIA written proposal)
Value of DERs reducing the frequency/scope of maintenance projects	Group III: WG Report Item 16	Non-priority item; WG did not discuss	
Benefits of DER penetration allowing for downsized replacement equipment due to be installed in the case of equipment failure or routing replacement of aging assets	Group III: WG Report Item 17	Non-priority item; WG did not discuss	

Appendix B

Appendix B is provided for reference only, i.e., to provide context for the proposals in the Final Report, but should not be considered a full component of the Final Report's recommendations.

Item 2.i: Automatically populate DER generation Profiles

Joint IOUs' Initial Proposal
LNBA Working Group

Summary of Recommendations

At the first long term refinement LNBA working group (WG) meeting held on July 7, 2017 the joint IOUs presented to the greater WG what was believed to be reasonable alterations to the LNBA spreadsheet tool to address long term refinement item 2.i in the Assigned Commissioner's Ruling dated June 7, 2017. This is a priority refinement in the ACR. The proposed alterations included the following:

1. Pre-Populate the LNBA Tool with publicly available DER shapes for solar, energy efficiency, and a generic baseload generation (flat shape).
    - IOUs recommend using public profile sources, specifically include NREL's PVWatts Calculator and E3's Energy Efficiency Calculator for solar and EE, respectively.
2. The solar and energy efficiency generation profiles would be obtained from public, vetted sources. This allows users to reproduce and obtain the DER shapes independently.
3. Location and PV system properties need to be determined to generate the appropriate solar profiles from PV watts.
4. A desired list of energy efficiency measures and technologies will need to be determined to obtain the appropriate EE profiles.
5. Other typical DER profiles can be included in the LNBA tool but should be publicly available.
    - It is expected that the WG stakeholders will submit all the DER profiles they wish to include in the new DER library.

Introduction and Background

After reviewing the IOUs demonstration B projects (Demo B), "the LNBA WG identified short-term improvements that improve the functionality of the LNBA tool and heat map. These improvements do not change the underlying LNBA analysis."[14]

The current version of the LNBA tool requires users to provide DER information such as the DER hourly profile. One of the improvements to the LNBA tool recommended by the WG and specified by the ACR is

[14] "Locational Net Benefits Analysis Working Group – Long Term Refinement Topics Scoping Document," More Than Smart, pg. 3.

to include options to automatically populate DER generation profiles.[15] The sample profiles provided in the LNBA tool would be illustrative only.

Discussion

IOUs propose to create DER profile library that includes a reasonable amount of normalized profiles of common DER types. The profiles will be normalized to 1 kW which would facilitate the scaling of the selected DER profile by a user inputted size. The DER profile library would be included in the updated LNBA Tool.

By including a library of profiles with stakeholder input, the needs of a large majority of users should be met. Future additions can be made to the profile library to keep up with emerging technologies or DER use cases.

For the public sources of DER generation profiles, the IOUs recommended using National Renewable Energy Laboratory's (NREL) PVWatts Calculator[16] and Energy and Environmental Economics' (E3) 2013-2014 Energy Efficiency Calculator[17] to obtain typical solar and energy efficiency profiles, respectively.

Solar

The PVWatts Calculator allows users to input a location, select an appropriate weather data, and provide PV system properties (e.g., size, tilt, DC/AC ratio). Once the above information is provided through the online website, an hourly generation profile can be downloaded.

The next steps to develop the solar generation profile would be to determine the necessary inputs: location, associated weather data location, and PV system properties for the generic profile to be pre-populated in the tool. Once the inputs have been determined, solar profiles can be created and added to the LNBA tool.

Energy Efficiency (EE)

E3's Energy Efficiency Calculator provides hourly energy efficiency profiles for various measures. These hourly profiles represent the latest hourly profiles from the Database for Energy Efficient Resources (DEER)[18]. The DEER is a CPUC database that contains information on energy efficient technologies and measures relevant to California.

The next step would be to select representative energy efficiency measures or technologies and obtain the hourly profiles to be added to the LNBA tool.

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[15] "Assigned Commissioner's Ruling Setting Scope and Schedule for Continued Long Term Refinement Discussions Pertaining to the Integration Capacity Analysis and Locational Net Benefits Analysis in Track One of the Distribution Resources Plan Proceeding," June 6, 2017, pg. 12.
[16] NREL's PVWatts Calculator can be found at: http://pvwatts.nrel.gov/
[17] E3's 2013-2014 Energy Efficiency Calculator can be found at: https://www.ethree.com/public_proceedings/energy-efficiency-calculator/
[18] DEER information can be found at: http://deeresources.com/

Other

Stakeholders are welcome and encouraged to submit additional typical hourly DER profiles to be included in the tool. However, it is recommended that the source of the profiles be public, vetted and readily available.

Conclusion and Next Steps

- The Joint IOUs recommend using public profile sources include NREL's PVWatts Calculator and E3's Energy Efficiency Calculator for solar and EE, respectively.
- To obtain solar profile(s) from PVWatts, input assumptions must be determined. These inputs include location, associated weather locations, and PV system properties. The joint IOUs seek input from the solar parties in the working group for a typical solar installation.
- To obtain the energy efficiency profiles, a set of recommended energy efficiency measures and technologies will need to be selected. The Joint IOUs will select some energy efficiency measures and present that selection to the working group.
- Working group members are encouraged to submit additional sources to other typical DER profiles that can be included in the LNBA Tool. These sources should be publicly available.

Item 4.i: Additional Locational Granularity into Avoided Energy

Joint IOUs' Initial Proposal
LNBA Working Group

Note: In the June 7 ACR, Item 4 states: "Incorporate additional locational granularity into Energy, Capacity, and Line Losses." The IOUs have subdivided this item into three separate items covering energy, line losses, and capacity (respectively).

Summary of Recommendations

6. Replace the system-wide avoided energy forecast from the 2016 DERAC with DLAP price forecasts for each IOU.
    - Remove the system-wide avoided energy values currently obtained from Energy and Environmental Economics' (E3) 2016 Distributed Energy Resource Avoided Cost (DERAC) model. Add default load aggregation point (DLAP) forecast for the three IOUs. DLAP prices represent the cost that the IOUs incur when serving its customers' load.
7. Consistent with current system-wide avoided energy values, the any GHG avoided cost component would be removed from the DLAP forecast since the LNBA tool incorporates a GHG forecast as a separate avoided cost component.
8. The next step is to propose a methodology for forecasting the DLAP prices.

Introduction and Background

The current avoided energy cost utilizes a system-wide forecast obtained from the 2016 DERAC model. The system-wide forecast does not provide any value differentiation between locations. As part of the recommendations following the IOUs' DRP demonstration project B, the LNBA WG recommended to update the avoided energy cost with more location specific values as an improvement to the LNBA tool.[19] For the long term refinement of the LNBA, this task is one of the priority items to be accomplished.[20]

At the first long term refinement LNBA working group (WG) meeting held on July 7, 2017 the joint IOUs presented to the greater WG what was believed to be reasonable alterations to the LNBA spreadsheet tool to address long term refinement item 4 – locational avoided energy in the Assigned Commissioner's Ruling dated June 7, 2017.

[19] "Locational Net Benefits Analysis Working Group – Long Term Refinement Topics Scoping Document," More Than Smart, pg. 4.

[20] "Assigned Commissioner's Ruling Setting Scope and Schedule for Continued Long Term Refinement Discussions Pertaining to the Integration Capacity Analysis and Locational Net Benefits Analysis in Track One of the Distribution Resources Plan Proceeding," June 6, 2017, pg. 12.

Discussion

The DLAP price is a weighted average of all the locational marginal prices (LMPs) within the DLAP area. The DLAP area represents a geographic area within CAISO where demand bids "shall be submitted and settled."[21] As noted by California Independent System Operator (CAISO), "load is bid in and settled at the DLAP LMP as opposed to the nodal LMP."[22] In other words, the DLAP price is what the IOUs pay to serve their customers. To follow the avoided cost methodology of the LNBA tool, the locational avoided energy forecast should be the DLAP forecasts associated with each IOU.

In order for the LNBA tool to be updated with the DLAP forecasts, a methodology must be developed to forecast the DLAP prices.

Conclusion and Next Steps

- Replace the system-wide avoided energy forecast from the 2016 DERAC with DLAP price forecasts for each IOU.
- DLAP prices represent the cost that the IOUs incur when serving their customers' load.
- The next step is to propose a methodology for forecasting the DLAP prices.
- The IOUs are currently evaluating the suitability of existing public DLAP forecasts.

[21] "Business Practice Manual for Definitions & Acronyms," CAISO, version 16, October 3, 2016, pg. 36.
[22] "Load Granularity Refinements, Pricing Study Results and Implementation Costs and Benefits Discussion," CAISO, January 14, 2015, pg. 11.

Item 4.i: Locational Avoided Energy

Joint IOUs' Revised Proposal
LNBA Working Group

Summary of Recommendations

1. Use IRP models to develop long-term forecasts of energy avoided cost at the DLAP level
2. Use a proxy methodology as an interim solution to develop DLAP price forecasts.
3. Once an IRP production cost model is built and vetted, consider using it to produce price forecasts to replace the proxy results.
4. Develop the price forecasts in the IDER as part of the update to the DERAC.
    a. Once adopted in the DERAC, the price forecast would be inputted into the LNBA tool.

Introduction and Background

As part of the Distribution Resource Plan (DRP) Track 1's Demonstration Project B (Demo B), the current avoided energy price forecast was obtained from the 2016 Distribution Energy Resource Avoided Calculator (DERAC, also known as the 2016 Avoided Cost Model). In the DERAC, the energy price forecast is determined in two steps. The first step determines an average annual system wide energy price. This annual energy price represents the price necessary to keep a CCGT "whole". In other words, the energy price plus capacity revenues must equal the fixed and variable costs of the CCGT. The second step shapes the annual price to hourly values. The DERAC utilizes 2015 day-ahead prices for NP-15 and SP-15 that are adjusted for forecasted heat rate changes from the RPS Calculator to determine hourly heat rate shapes. Applying the shape to the annual energy provides the DERAC with an hourly NP-15 and a SP-15 energy price forecast.

As part of the long term refinements for LNBA, the working group was tasked to explore more locational avoided energy price forecasts. In the July working group meeting, the IOUs proposed using three default load aggregation point (DLAP) price forecasts, one for each IOU, as an improvement to the current DERAC forecasts. To serve load, the IOUs pay the DLAP price. Thus, in an avoided cost methodology, the DLAP price represents the proper value for avoided energy prices from DER. The IOUs requested that E3 provide analysis and methodologies assessing the IOU proposal.

Discussion

In the November working group meeting, E3 provided an overview of their findings. During the discussion, E3 presented two options available to develop DLAP forecasts.

The first option is to utilize a similar approach to the methodology used in the DERAC. This proxy methodology would utilize recent historical or forecasted hourly DLAP energy prices modified by heat rate factors to obtain hourly energy prices forecasts. The heat rate factors would be obtained from the CPUC's Integrated Resource Plan (IRP) RESOLVE model. By utilizing the IRP RESOLVE model, the heat rate factors would incorporate the future impacts of California policy (e.g., SB350 and Governor's 2030

Greenhouse Gas Reduction goal). The proxy method would improve the current DERAC methodology (1) by providing more locational granularity (because it utilizes hourly DLAP energy prices) and (2) by utilizing updated heat rate factors that are consistent with the IRP. In addition, this proxy methodology could be implemented in a relatively short time. However, additional analysis of the results from the proxy methodology would be necessary to ensure the validity of the price forecast. For example, the Resolve model only uses 37 representative daytypes to simplify the modeling. These 37 daytypes would need to be matched to all hours of the year to develop the heat rate factors. When transitioning from one daytype to another, there is the potential for the price forecast to change suddenly due to the difference in daytypes.

The second option would be to utilize a full annual, hourly production cost model to develop price forecasts. A production cost model simulates the grid by minimizing the cost of operating the grid subjected to constraints such as serving load, individual generator operational constraints, and transmission limits. Thus, a production cost model would be able to provide a more detailed and precise view of future prices, especially by location if locational price differences change over time in response to load, resource, or transmission changes. The IRP proceeding currently is planning to develop a SERVM model, a hybrid resource adequacy and production cost software, to further assess the impacts of scenarios on the grid and would also incorporate future effects of California policy which could potentially be leveraged to provide an energy forecast. While SERVM can provide an energy forecast, the software is more focused on resource adequacy. Because of SERVM's focus on resource adequacy, it may be necessary to translate the SERVM model to a more dispatch based production cost model (e.g., PLEXOS, AURORA, or Gridview) which could provide a robust energy forecast. The IRP's SERVM model is not expected to be finished until the middle of 2018. Additional vetting or analysis may need to occur to validate the results from any production cost model.

Recommendation

Based on the availability and benefits of the above two methodologies, the IOUs recommend using the proxy methodology as an interim solution to provide locational DLAP price forecasts. Once an IRP production cost model is ready and has been validated, the IOUs recommend that the interim methodology results be replaced with the production cost model results, assuming that the production cost model price forecast would be more accurate. Finally, the IOUs recommend that the development of the prices using the proposed phased approach should be done in annual update to the DERAC as part of the IDER proceeding. This would allow stakeholders to review the results of the methodology, leverage the existing process to update the DERAC, and fulfill the DRP Track 1 decision to inform the DERAC of improvements from the LNBA cost effectiveness use case. Once adopted in an updated DERAC, the LNBA tool would be updated to reflect the changes for the LNBA deferral use case.

Item 4ii. Capacity: Incorporate additional locational granularity into Capacity avoided cost values

Joint IOUs' Initial Proposal
LNBA Working Group

Summary of Proposal

1. The Joint IOUs (SDG&E, SCE and PG&E) propose to develop locational generation capacity avoided cost values at the CPUC's Local Resource Adequacy (Local RA) areas, which are based on CAISO's Local Capacity Requirement Area (LCR Area) level.
    1.1. Areas outside of a Local RA area would receive a system-level generation capacity avoided cost
2. The IOUs propose to use the recent, joint-IOU system-level generation capacity price forecast that was provided as a benchmark in the RPS proceeding.
3. Locational generation capacity avoided cost values will be determined using Local RA multipliers developed from the most recent data in the CPUC RA Report and applied to a system-level forecast that includes both short-run (i.e. RA-based) and long-run generation capacity value.
4. In each year, all generation capacity prices are capped at the net cost of new entry (CONE) for that year.
5. In the year that the system-level generation capacity price forecast reaches CONE, all other areas are also set at CONE

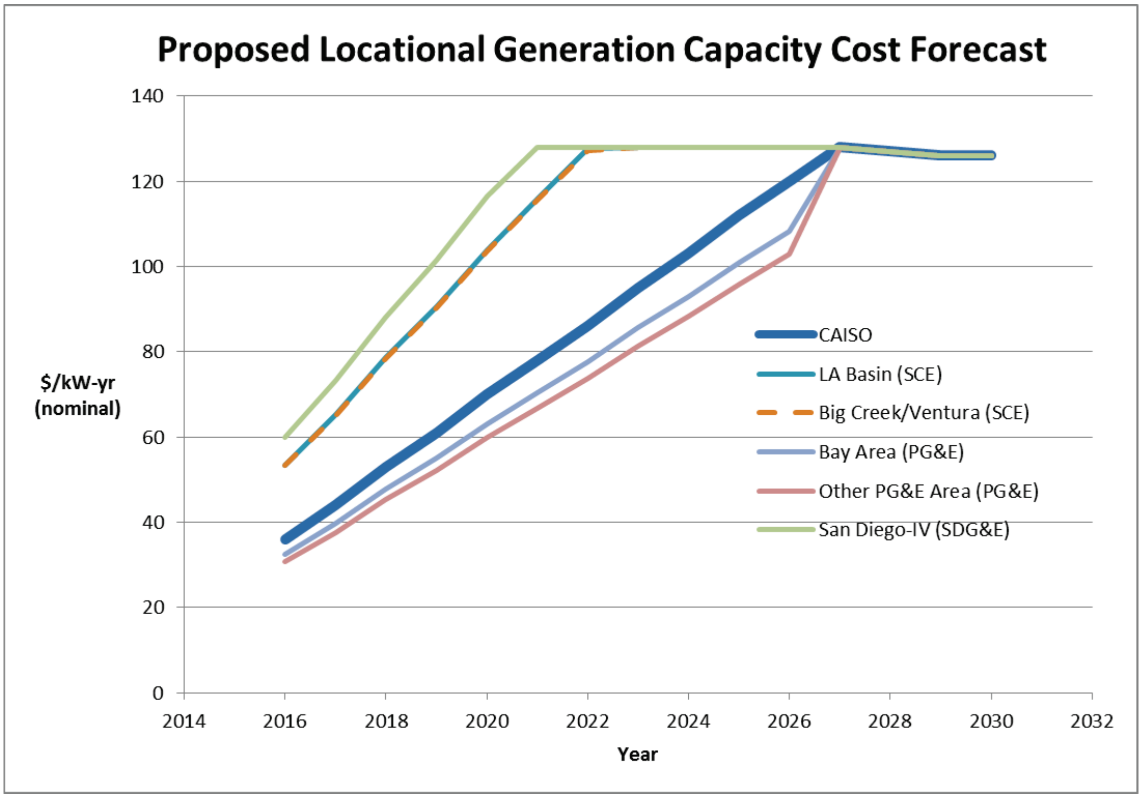


Fig. 1

Introduction and Background

1. **Available Data on Locational Variation in Generation Capacity Value: The CPUC RA Report**
    1.1. The annual CPUC Resource Adequacy (RA) Report is the only public source of generation capacity price information in California. It provides aggregated RA contract price information at both the system-level and the Local RA area. Note: six small CAISO LCR areas in PG&E's territory are aggregated as one CPUC Local RA area, called "Other PG&E Area".
    1.2. Since RA is not transacted in a centralized capacity market, this is the only public source of information with RA price information for system-level and Local RA.
    1.3. Although this is the best available information, this report is based on voluntary responses to a CPUC data request and does not necessarily capture the entirety of RA contracts and transactions.
    1.4. The CPUC's latest RA report is available here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942
2. **Resource Adequacy (RA) and Short-Run Generation Capacity Value**
    2.1. Load Serving Entities (LSEs) subject to CPUC jurisdiction must participate in the Resource Adequacy (RA) program.
    2.2. RA refers to the program as well as the "capacity product" that LSEs must use to meet their System RA, Local RA and Flexible RA requirements. The capacity product can come from an LSE's generation portfolio and/or through contracts with generators to procure the RA-qualifying MW attributes of the generator.

2.3. Here we focus on System and Local RA, since Flexible RA does not vary within the CAISO.
2.4. In general, CAISO determines the RA requirements for reliable operation of the grid, and CPUC allocates those requirements to its jurisdictional LSEs. This requirement includes a 15% planning reserve margin.
2.5. Local RA is essentially no different from System RA, except that it is located in specific areas (i.e. load pockets) that have limited access to the transmission system.
  2.5.1. Local RA is the only RA product that is "locational" – i.e. both the requirements, which are based on the August peak load in the LCR area, and the product are specific to a location on the system.
2.6. On a monthly basis, each LSE must demonstrate to CPUC that they have in their resource portfolio, either through ownership or contract, sufficient RA resources (i.e. operational generating capacity) to meet their RA requirement.
2.7. When DERs qualify as an RA resource, they can be compensated through a contract with an LSE for their RA attribute.
2.8. When DERs don't qualify as RA but have an impact on the LSE's RA requirement, those DERs can avoid or increase the LSE's RA compliance costs.
  2.8.1. For example, if EE reduces the LSE's peak load by 5 MW, then one can calculate the associated RA procurement cost reduction.
  2.8.2. Conversely, if EVs increase the LSE's peak load by 5 MW, one can calculate the associated RA procurement cost increase.
2.9. Regardless of whether DERs qualify as RA or impact an LSE's RA requirement, RA prices represent the short-run generation capacity avoided cost, since in the near-term, DERs simply increase or decrease an LSE's RA procurement.

3. Long-Run Generation Capacity Avoided Cost and Net Cost of New Entry (CONE)

3.1. In general, the near-term RA prices are low relative to the cost of new generation, because there is an excess of generators available to provide additional RA if needed.
3.2. In the long-run, however, generators may be retired and loads may grow such that there is no-longer an excess of generators. In this year, the "resource balance year" (RBY), LSEs will need to contract with a new generator in order to meet their RA obligation.
3.3. The net cost of new entry (CONE) is an estimate of how much generation capacity would cost from a new generator. It is an estimate of the levelized annual cost of building a new generator less the levelized annual energy and ancillary service revenue the plant would be expected to generate.
3.4. In the RBY and beyond, DERs are reducing the amount of new generating capacity that must be built; hence the CONE represents the long-run generation capacity avoided cost.
3.5. In any year, CONE represents the maximum generation capacity avoided cost, since it reflects the cost of increasing generating capacity by building a new generator.
3.6. CONE includes cost components, such as the cost of land for a new generator, which could vary by location; however, since CONE is based on a system-level shortage of resources, such components are evaluated locationally to calculate location-specific variants of the CONE.

Discussion

1. Level of Granularity for Generation Capacity

1.1. As described above, RA can be either System or Local, depending on whether a resource is located in a CPUC-designated Local RA area, informed by CAISO's LCR Areas.

1.2. The highest level of granularity for RA price variation is therefore at the Local RA level.

2. LNBA WG discussions

2.1. During the 7/15 LNBA WG meeting, the IOUs introduced the CPUC RA report and existing public generation capacity price forecasts, including the forecast currently in the Demo B LNBA tool.

2.2. Discussion centered on the need to reconcile the requirement for location-specific generation capacity avoided costs in LNBA with the fact that the only locational information available (i.e. the CPUC RA report) applies to the short-run generation capacity cost (i.e. RA prices) but not to the long-run generation capacity avoided cost (i.e. CONE). Stakeholders expressed openness to an IOU proposal which used RA price data to develop short-run locational generation capacity avoided costs.

2.3. During the 8/15 LNBA WG meeting, the IOUs presented the proposal described here and answered questions. This proposal incorporates feedback from that discussion.

3. Use of the Resource Balance Year in Light of IDER Decision D.16-06-007

3.1. Decision 16-06-007 in the IDER proceeding required the use of capacity benefits based on the long-run avoided capacity cost when doing cost-effectiveness analyses of demand-side management programs. Similarly, it prohibited the concept of resource balance year (a.k.a. year of need) in the Commission's DER avoided cost model.

3.2. LNBA is not currently used for the purpose of evaluating cost-effectiveness of DER programs and tariffs. Rather it is an indicator of locational value for DER benefits that could be calculated using Least-Cost/Best-Fit methodology in an IOU's procurement solicitation. As such, this proposal is not considered to be limited by D.16-06-007 regarding the use of resource balance year.

3.3. If this proposal is incorporated into the LNBA methodology and if a Commission decision directs the LNBA to be used for purposes of DER cost-effectiveness in IDER, the Commission would also have to modify D.16-06-007 and potentially require additional stakeholder review in the IDER proceeding.

Proposal

1. Calculate short-term LCA Multipliers

1.1. The IOUs propose to develop short-term RA price multipliers for each Local RA area by dividing the most recent[23] weighted average Local RA prices (see Table 8 in the CPUC RA Report) by the weighted average price for the CAISO system.

1.2. This yields the following locational factors for identified areas within the CAISO territory:

Area	LA Basin (SCE)	Big Creek/ Ventura (SCE)	Bay Area (PG&E)	Other PG&E Area (PG&E)	San Diego-IV (SDG&E)	System
2016-20 Wtd. Avg. Price x 12 ($/kW-yr)	43.44	43.32	26.4	25.08	48.72	29.28
LCA factors based on wtd. avg. LCA price WRT system price	1.48	1.48	0.90	0.86	1.66	1.00

[23] The prices in this table are for "compliance years 2016 – 2020." Since LSEs procure RA in advance of the year that it's needed, the most recent transactions will include RA purchases for "delivery" in future years. These are all lumped together in the RA Report.

Table 1

2. **Apply Local RA Multipliers to Short-Run Generation Capacity Price Forecast to yield locational Generation Capacity Values**
   2.1. These locational factors, since they are based on RA prices, are applicable to short-run avoided generation capacity cost.
   2.2. For this proposal, the IOUs propose using the Joint IOU RA Benchmark Price Forecast Proposal filed in the RPS Proceeding
      2.2.1. When LSEs request offers in an RPS solicitation, they estimate the value of each resource to decide which to procure. This includes estimating the resource's RA value.
      2.2.2. In 2016, the joint IOUs filed a public, informational RA price forecast to help RPS providers understand how RA is valued.
      2.2.3. The joint IOUs developed this forecast using a version of E3's DERAC calculator used in the SGIP program with inputs developed using public information to mimic how the IOUs view the value of RA in procurement.
      2.2.4. This forecast includes both short-run and long-run generation capacity prices.
      2.2.5. This filing is available here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M168/K107/168107777.PDF
   2.3. These locational factors are thus multiplied by the system-level short-run (i.e. pre RBY) RA price forecast for each year provided by the joint IOUs in the RPS proceeding, with the result capped at CONE, since this would be the maximum avoidable cost in any year. Though some areas will reach CONE before the RBY, this does not necessarily mean that that area has a need for new capacity or has an area-specific RBY.
   2.4. For the RBY and subsequent years, the CONE becomes the RA price forecast across all areas.
   2.5. The result is provided here in Fig. 1.

Conclusion and Next Steps

1. The proposed approach uses the available public data on locational generation capacity value – the RA price report – to develop locational generation capacity avoided costs in a way that is consistent with the nature of that data as short-term RA price information.
2. The proposed method yields results that more accurately reflect the IOUs' actual avoided costs than the current DERAC values.
3. LNBA WG participants are invited to provide written comments on this proposal, including on concerns regarding consistency with D.16-06-007 for inclusion in the 8/31 LNBA WG status report.

Topic 4ii-Capacity: Incorporate additional locational granularity into Capacity avoided cost values

SEIA Proposal
LNBA Working Group

Summary of Proposal

SEIA proposes to develop locational generation capacity avoided cost values based on the loss-adjusted Cost of New Entry (CONE) in each IOU service territory. This would be consistent with D. 16-06-007 which established the CONE as the avoided generation capacity cost for DERs, without the use of a Resource Balance Year (RBY) to transition from short-run to long-run avoided capacity costs that accurately value distributed energy resources.

Introduction and Background

4. **Available Data on Locational Variation in Generation Capacity Value: The CPUC RA Report**
    - 4.1. The annual CPUC Resource Adequacy (RA) Report is the only public source of short-run generation capacity price information in California. It provides aggregated RA contract price information at both the system-level and the Local RA area.
    - 4.2. Since RA is not transacted in a centralized capacity market, this is the only public source of information with RA price information for system-level and Local RA.
    - 4.3. Although this is the best available information, this report is based on voluntary responses to a CPUC data request and does not necessarily capture the entirety of RA contracts and transactions.
    - 4.4. The CPUC's latest RA report is available here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942
5. **Resource Adequacy (RA) and Short-Run Generation Capacity Value**
    - 5.1. Load Serving Entities (LSEs) subject to CPUC jurisdiction must participate in the Resource Adequacy (RA) program.
    - 5.2. RA refers to the program as well as the "capacity product" that LSEs must use to meet their System RA, Local RA and Flexible RA requirements. The capacity product can come from an LSE's generation portfolio and/or through contracts with generators to procure the RA-qualifying MW attributes of the generator.
    - 5.3. Here we focus on System and Local RA, since Flexible RA does not vary within the CAISO.
    - 5.4. In general, CAISO determines the RA requirements for reliable operation of the grid, and CPUC allocates those requirements to its jurisdictional LSEs. This requirement includes a 15% planning reserve margin.
    - 5.5. Local RA is essentially no different from System RA, except that it is located in specific areas (i.e. load pockets) that have limited access to the transmission system.

5.5.1. Local RA is the only RA product that is "locational" – i.e. both the requirements, which are based on the August peak load in the LCR area, and the product are specific to a location on the system.

5.6. On a monthly basis, each LSE must demonstrate to CPUC that they have in their resource portfolio, either through ownership or contract, sufficient RA resources (i.e. operational generating capacity) to meet their RA requirement.

5.7. When DERs qualify as an RA resource, they can be compensated through a contract with an LSE for their RA attribute.

5.8. When DERs don't qualify as RA but have an impact on the LSE's RA requirement, those DERs can avoid or increase the LSE's RA compliance costs.

5.8.1. For example, if EE reduces the LSE's peak load by 5 MW, then one can calculate the associated RA procurement cost reduction.

5.8.2. Conversely, if EVs increase the LSE's peak load by 5 MW, one can calculate the associated RA procurement cost increase.

6. Long-Run Generation Capacity Avoided Cost and Net Cost of New Entry (CONE)

6.1. In general, the near-term RA prices are low relative to the cost of new generation, because there is an excess of generators available to provide additional RA if needed.

6.2. In the long-run, however, generators may be retired and loads may grow such that there is no-longer an excess of generators. In this year, the "resource balance year" (RBY), LSEs will need to contract with a new generator in order to meet their RA obligation. Before its elimination the RBY was a much debated concept and year and was based on when lumpy supply-side solutions would be needed to meet capacity needs. As. D16-06-007 finds, the RBY is no longer appropriate in a high-DER world.

6.3. The net cost of new entry (CONE) is an estimate of how much generation capacity would cost from a new generator. It is an estimate of the levelized annual cost of building a new generator less the levelized annual energy and ancillary service revenue the plant would be expected to generate. The value of CONE can differ by utility service territory, due to factors such as siting costs, the expected energy and ancillary service rents, and different environmental regulations.

6.4. In the RBY and beyond, DERs are reducing the amount of new generating capacity that must be built; hence the CONE represents the long-run generation capacity avoided cost.

6.5. In any year, CONE represents the maximum generation capacity avoided cost, since it reflects the cost of increasing generating capacity by building a new generator.

6.6. CONE includes cost components, such as the cost of land for a new generator, which could vary by location; however, since CONE is based on a system-level shortage of resources, such components are evaluated locationally to calculate location-specific variants of the CONE.

6.7. CONE also should be adjusted for losses, because 1 MW of capacity supplied by DERs behind the meter is equivalent to 1 + Loss % MW of generation-level capacity from a new utility-scale generator, as a result of the losses between the utility-scale generator and loads. These loss percentages will vary by location, and thus so will CONE.

Discussion

4. Level of Granularity for Generation Capacity

4.1. As described above, RA can be either System or Local, depending on whether a resource is located in a CPUC-designated Local RA area, informed by CAISO's LCR Areas.

4.2. The highest level of granularity for RA price variation is therefore at the Local RA level.

5. **LNBA WG discussions**
   5.1. During the 7/15 LNBA WG meeting, the IOUs introduced the CPUC RA report and existing public generation capacity price forecasts, including the forecast currently in the Demo B LNBA tool.
   5.2. Discussion centered on the need to reconcile the requirement for location-specific generation capacity avoided costs in LNBA with the fact that the only locational information available (i.e. the CPUC RA report) applies to the short-run generation capacity cost (i.e. RA prices) but not to the long-run generation capacity avoided cost (i.e. CONE). Stakeholders expressed openness to an IOU proposal which used RA price data to develop short-run locational generation capacity avoided costs.
   5.3. During the 8/15 LNBA WG meeting, the IOUs presented a proposal to parties and answered questions. This document outlines SEIAs concurrence on some issues of fact but rejection of the proposed replacement of CONE with local RA and a local RBY, in light of the long-run value of DERs and the Commission's recent elimination of the Resource Balance Year in D.16-06-007.
6. **Use of the Resource Balance Year in Light of IDER Decision D.16-06-007**
   6.1. Decision 16-06-007 in the IDER proceeding required the use of capacity benefits based on the long-run avoided capacity cost when doing cost-effectiveness analyses of demand-side management programs. Similarly, it prohibited the concept of resource balance year (a.k.a. year of need) in the Commission's DER avoided cost model.
   6.2. The IOUs argue that the LNBA will not be used for the purpose of evaluating cost-effectiveness of DER programs and tariffs. A Proposed Decision in R.14-08-013 released August 25, 2017 reaffirms that a revised DERAC calculator is an intended use case of the LNBA.
   6.3. If this proposal is incorporated into the LNBA methodology and if a Commission decision directs the LNBA to be used for purposes of DER cost-effectiveness in IDER, the Commission would also have to modify D.16-06-007 and potentially require additional stakeholder review in the IDER proceeding.
   6.4. SEIA also observes that the IOU method uses location-specific short-run RA values, but a system-wide resource balance year. Local areas with high short-run RA values are presumably closer to the RBY in that local area than the system as a whole, and thus should increase more quickly than system-average capacity values. However, the IOU method does not use RBYs for local resources areas.
   6.5. SEIA and its members supported D. 16-06-007's elimination of the resource balance year concept when determining the cost-effectiveness of DERs. SEIA agrees with D. 16-06-007's conclusion to eliminate the RBY because distributed energy resources are displacing new capacity rather than short-term capacity, and because the RBY concept fails to recognize the full value of small-increment, short-lead-time, high priority resources such as DERs.

Proposal

1. **Calculate the loss-adjusted CONE for each IOU service territory.** SEIA proposes to develop IOU-specific, loss-adjusted CONE values for each IOU service territory. Loss adjustments should be based on peak period line losses in each IOU service territory from the generation level to the load level. These IOU-specific CONE values would reflect locational differences due to (1) differences in peak period losses in each IOU service territory and (2) different CONE calculations given variations in

CONE between service territories as a result of differences in siting costs, energy rents, environmental costs, or the base cost of the marginal source of capacity.

Conclusion and Next Steps

4. SEIA proposes to use loss-adjusted CONE values specific to each IOU service territory as the locational avoided cost of capacity for the LNBA.
5. The proposed method yields results that more accurately reflect the IOUs' actual avoided costs than the current DERAC values which do not use IOU-specific CONE values.

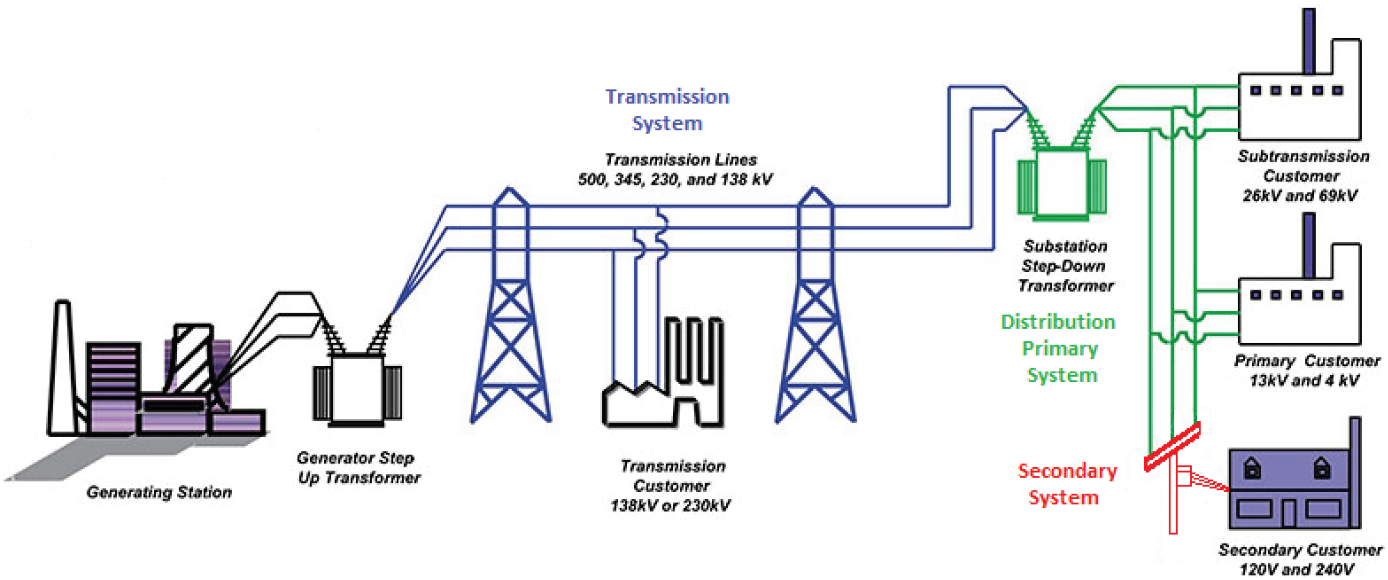
Item 4iii: Locational Based Line Loss Calculations

Joint IOUs' Initial Proposal

LNBA Working Group

Summary of Recommendations

- The LNBA working group (WG) collectively recommends that the existing system loss factor in the LNBA tool be split into several loss factors separately accounting for losses any DER may alter on a local transmission area, sub transmission, distribution primary, and distribution secondary systems they are interconnected and downstream of. The diagram below illustrates these separate systems.



- The LNBA WG recommends that the transmission loss factor remain the same for all DERs in each respective IOU's service territory as transmission losses will not be significantly impacted by deploying DER in one location vs another.
- SCE will perform a study on their own behalf to evaluate if their sub-transmission losses vary significantly by location. (SCE specific)
- The IOUS will expend the most effort evaluating distribution primary losses in a more detailed circuit modeling exercise for some subset of each IOUs distribution circuits. The evaluation will help determine the effect of DER location on distribution circuit losses and will help guide how loss factors should be included in the LNBA and whether the IOUs should pursue a more elaborate/labor intensive methodology of calculating location specific loss factors for each circuit/section
- The IOUs will also perform an evaluation of secondary system losses

- Future analysis may evaluate losses incurred by backfeeding secondary networks and distribution transformers.
- IOUs will develop high level cost estimates/timeframes of implementing various line loss calculation methodologies

Introduction and Background

As part of Demonstration Project B (Demo B), the IOUs coordinated with E3 to develop the LNBA tool which includes IOU system wide specific loss factors. The loss factors were used to estimate the benefit that DERs provide by avoiding line losses. For example, if a customer needs 0.9 MWh of energy, a generator would need to provide 1.0 MWh of energy to account for 10% line losses to deliver that energy. Locating DERs near the customer to provide the energy would avoid the both the energy needed by the customer as well as the energy needed to account for the line losses.

As part of the assigned commissioner ruling on long term refinements to ICA and LNBA, the Commission requests to “incorporate additional locational granularity into…line losses.” The working group has suggested, as a first step, assess the variability of the line losses.

Discussion

- For a typical Electric system with large scale transmission interconnected generation feeding customers far away from its generating sources average losses are typically around 10%
- The existing LNBA tools currently calculates a DERs ability to reduce losses by either reducing load or delivering generation closer to load by multiplying the DER output by 1+system average loss factor. (if the average system losses was 10% this number would be 1.1) In addition to this the LNBA tool also evaluates the DER as providing 1.1 * its output for capacity reduction which help smaller DERs meet larger load reduction requirements in the interest of deferring a project
- Calculating losses is computationally intense because losses increase or decrease based on many different variables. Loading, load frequency, load allocation on a circuit, circuit conductor length, voltage level, conductor type, generation location, capacitor location, power factor, system operations, and other factors all play a role in determining losses.
- Because so many components go into line loss calculations one requires a large amount of data as well as data accuracy to accurately calculate line loss reductions caused by a DER. Even with precise data and calculations the distribution systems are dynamic in that loads, generation, and circuits configurations are subject to change all the time so the value of reduced losses is an estimate only.
- The LNBA WG acknowledges there may not be evidence that the variation in loss reduction is significant enough to warrant intense IOU effort to develop the tools necessary to estimate line loss reduction more accurately, however the IOUs will conduct a preliminary evaluation of line loss variation in order for the greater WG to determine if it is actually worth pursuing and if so to what degree of accuracy. The results of this preliminary study will be presented at the November WG meeting.
    - Each IOU will perform an analysis that follows the following steps:
        - Select a set of feeders for analysis seeking to capture a cross section on characteristics most likely to influence losses (e.g. length, voltage, loading)

    - Evaluate variability of losses among the selected feeders
    - Evaluate variability of losses within the selected feeders (i.e. different locations on each feeder)
    - Evaluate LNBA results sensitivity to losses
    - Recommend locational loss factor approach for LNBA tool (e.g. level of granularity, method for developing loss factors) that balances complexity with need to capture loss factor variability as a driver of LNBA results
- The preliminary study will serve to allow the allocation of resources to studying issues that have a more quantifiable impact to the LNBA than line losses in the interim.

Conclusion and Next Steps

Perform the Preliminary study on distribution primary line losses, secondary losses, and export losses and share results with working group at meeting in November.

Item 4.iii: Locational Based Line Loss Calculations

Clean Coalition suggested edits

Clean Coalition submitted edits to the Joint IOUs' proposal recommending that the transmission loss factor remain the same for all DERs in each respective transmission area identified by CAISO as transmission losses will not be significantly impacted by deploying DER in one location vs. another within these areas. Clean Coalition additionally submitted an addendum referencing the CAISO's local capacity technical analyses final reports and study results from 2012 and 2013. To preserve the tracked changes, these may be found here:

https://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-4-Line-loss-LT-Refinement-write-up-Clean-Coalition-edits.docx

Item 4.iii: Locational Based Line Loss Calculations

Joint IOUs' Revised Proposal

LNBA Working Group

Summary of Recommendations

After performing additional line loss studies to enhance understanding of line loss variance across distribution feeders and distribution secondary systems, the joint IOUs have the following proposals for how line loss changes should be accounted for in the various LNBA uses cases.

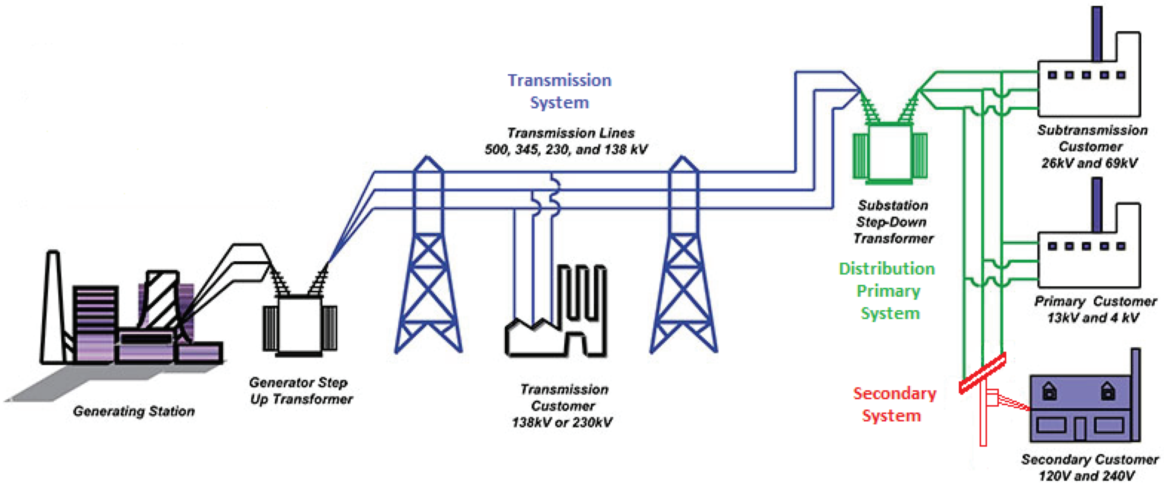
1. **For the DERAC calculator/cost effectiveness use cases** the IOUs recommend that we continue to use each IOU's respective publicly available transmission and distribution loss factors as multipliers to the avoided energy cost/peak generation capacity value streams a DER is forecasted to provide. The system average values[24] will adequately reflect the added value of typical DERs in reducing line losses without overcomplicating data input to the calculators or the analysis required to produce the LNBA mapping layers. The previously used distribution factors include both distribution primary and secondary system losses. Variation in secondary system losses will be disregarded due to lack of significance when evaluating DERs cost effectiveness at a high level
2. **For the project deferral/deferral framework use case** the IOUs recommend that some level of locational differentiation of losses will be incorporated into the LNBA tool; the level of detail is contingent on volume of projects identified in each IOU's system-wide rollout of LNBA for the deferral use case. The more location specific loss factors will be included in the LNBA tool to be recalculated and displayed on the heat maps. As a potential future improvement of the LNBA tool, locational loss factors would also reflect different voltage levels at which DER may be deployed: primary or secondary. Considering the challenges and variation of secondary systems, the first initial implementation will include loss factors from the primary distribution system. Consistent with the analysis presented here, some DERs not coincident with load that may increase losses and will be assessed as providing less generation avoided costs.

Introduction and Background

DERs alter the amount of energy losses on various parts of the electric grid differently, therefore the IOUs have segregated the evaluation of line losses to different portions of electric system. The IOUs have evaluated DER impact on the losses realized on the transmission, sub transmission (blue),

[24] The DERAC tool currently uses PTO-level average transmission loss factors; however, once LCR area granularity for generation capacity avoided costs is incorporated into LNBA, then LCR area specific transmission loss factors can be applied.

distribution primary (green), and distribution secondary systems (red). The diagram below illustrates these separate systems.



As part of Demonstration Project B (Demo B), the IOUs coordinated with E3 to develop the LNBA calculator tool which includes IOU system wide average loss factors for distribution and transmission. The loss factors were used to estimate the additional avoided energy costs, avoided generation costs, and avoided capacity needs at peak realized by a DER in reducing line losses. To clarify how these loss factors were applied in evaluating DER value see the example below.[25]

EXAMPLE:

IF….
Distribution System Losses (D_{Losses}) =4%
Transmission System Losses (T_{Losses}) =2%
Pre DER Circuit load = 6 MW continuous
DER Rating= 1 MW continuous

THEN
Pre DER yearly circuit energy consumption = 6MW *8760 Hours = 52,560 MWh
Pre DER yearly circuit energy losses = 52,560 MWh*(T_{Losses}+ D_{Losses}) =52,560 MWh * .06 = 3153.6 MWh

Yearly avoided energy credited to DER = DER Rating *(1 + (T_{Losses}+ D_{Losses}))* 8760 hours =
1 MW *1.06 *8760 = **9285.6 MWh** -8760MWh = **525 MWh** exclusively derived from reduction in yearly line losses

[25] Note that since the load is flat in all hours, the peak loss factor used to calculate avoided generation capacity is the same as the average loss factor used to calculate avoided energy. More typically, a distinction is made to calculate generation capacity and energy avoided cost, respectively.

Avoided Generation Capacity (Resource Adequacy) = DER Rating * (1 + (T_{Losses}+ D_{Losses})) = 1MW *(1+(.02+.04) = **1.06MW** resultant avoided RA

Increased Distribution Circuit Capacity = DER Rating * (1 + D_{Losses}) = 1MW *(1+.04)= **1.04 MW** Line capacity increase (For project deferral)

The LNBA working group expressed concern that using the system average loss values was not a sufficient way to account for the locational variability in DER line loss reduction. While the LNBA working group acknowledged that the variation in losses may not be significant enough to warrant intense IOU effort to develop the tools necessary to estimate line loss reduction more accurately and then extend the LNBA tool to incorporate more granular losses system-wide, the working group decided it was worth examining in greater detail. The IOUs then performed a more detailed evaluation of line loss variation for the greater WG to determine if detailed calculations of line losses were worth pursuing and if so to what degree of accuracy. The results of this preliminary study were presented at the November WG meeting and are included below.

Line Loss Variability Study Results

Per the September LNBA WG meeting each IOU was to perform an analysis using the following steps:

1. Select a sample size of distribution feeders to evaluate in preliminary study
2. Define circuit types to reflect differing characteristics
    a. i.e. Rural large service area, urban small service territory, and suburban medium size territory
    b. Uniform loading, spot load, express run circuit
    c. High % loaded circuit, medium %. Low %
3. Evaluate base circuit model for maximum, minimum, and median loading levels to see the baseline %/kW losses on each circuit
4. Model generation on baseline conditions created in #2
5. Record the kW losses from baseline condition determined from #2
6. Calculate maximum losses % change and min loss %
7. Use line loss study results to estimate sensitivity on LNBA results
8. Perform similar study for secondary network scaling generation and load

Example Results:

To aid with interpretation of the results, consider the following example:

Power flow results with no new DER added:

- Feeder Native Load (aka end use consumption): 5 MW
- Feeder Line Losses: 250 kW
- New DER Generation: 0 MW

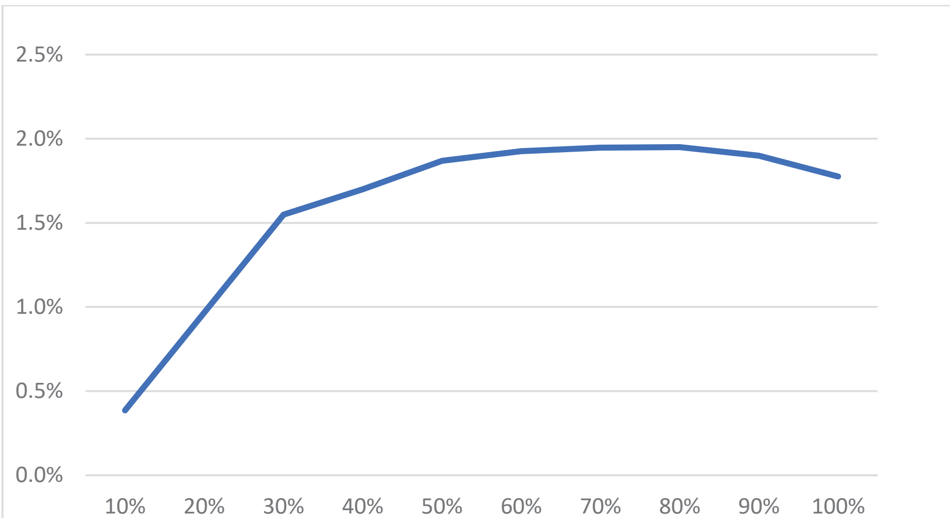
Power flow results with new DER added:

- Feeder Native Load (aka end use consumption): 5 MW
- Feeder Line Losses: 200 kW
- New DER Generation: 1 MW

The effect of adding a 1 MW DER on the line losses was a 50 kW reduction. Hence as a percent of the DER size, the loss factor is 50kW/1000kW = 5%. The results below are presented as percent as in the example above as well as kW. To convert kW to percent simply divide by 1,000. A hypothetical meter at the feeder head would read 5,250 kW before the DER is added and 4,200 kW after the new DER.

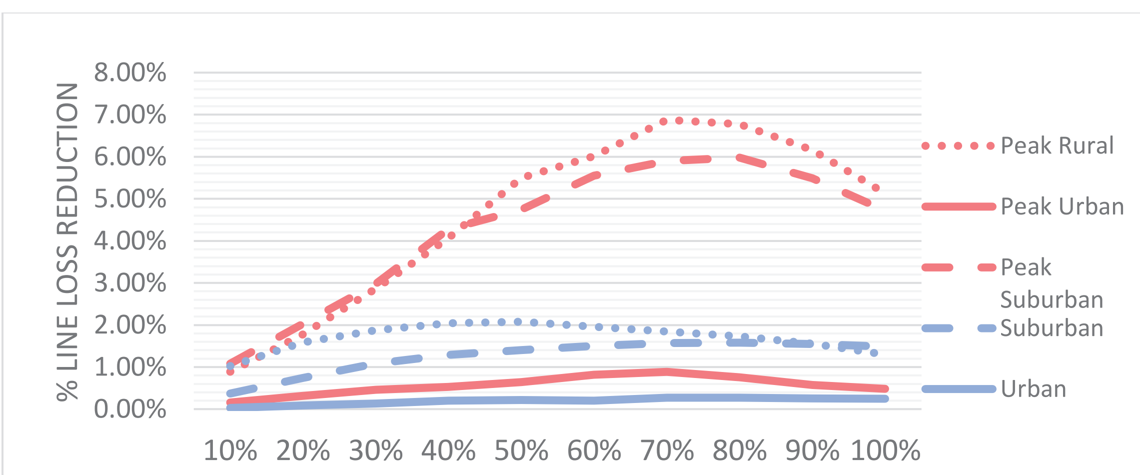
Southern California Edison Results

Distribution Primary % Line Loss Reduction Relative to 1 MW Generator Nameplate

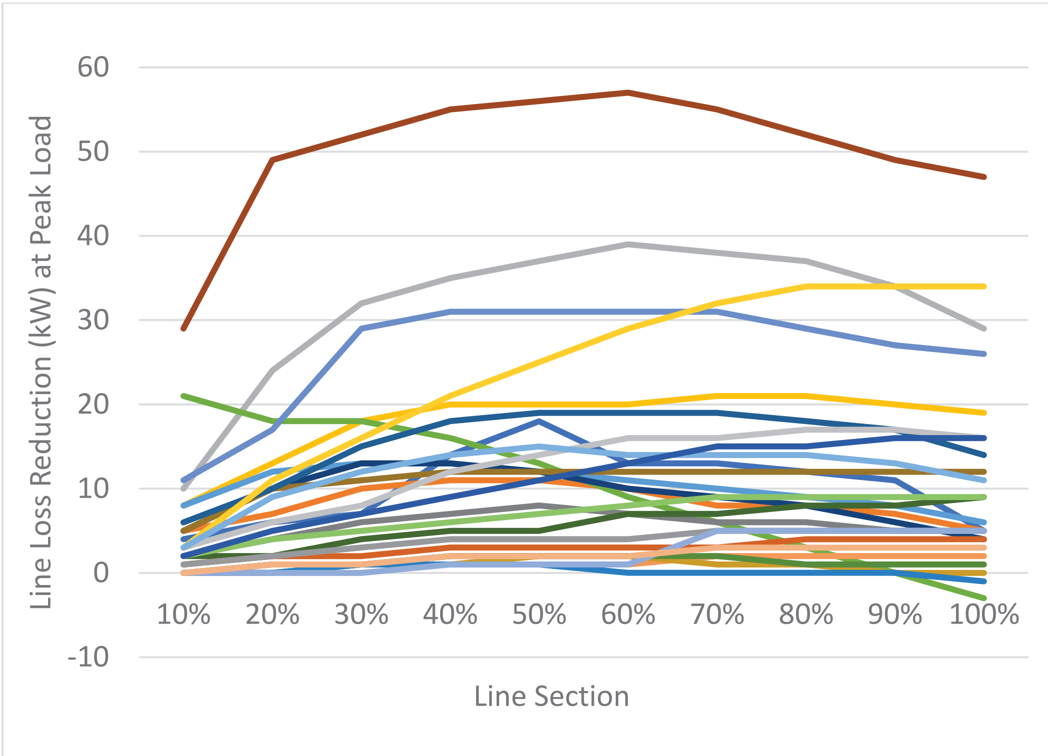


San Diego Gas & Electric Results (12kV)

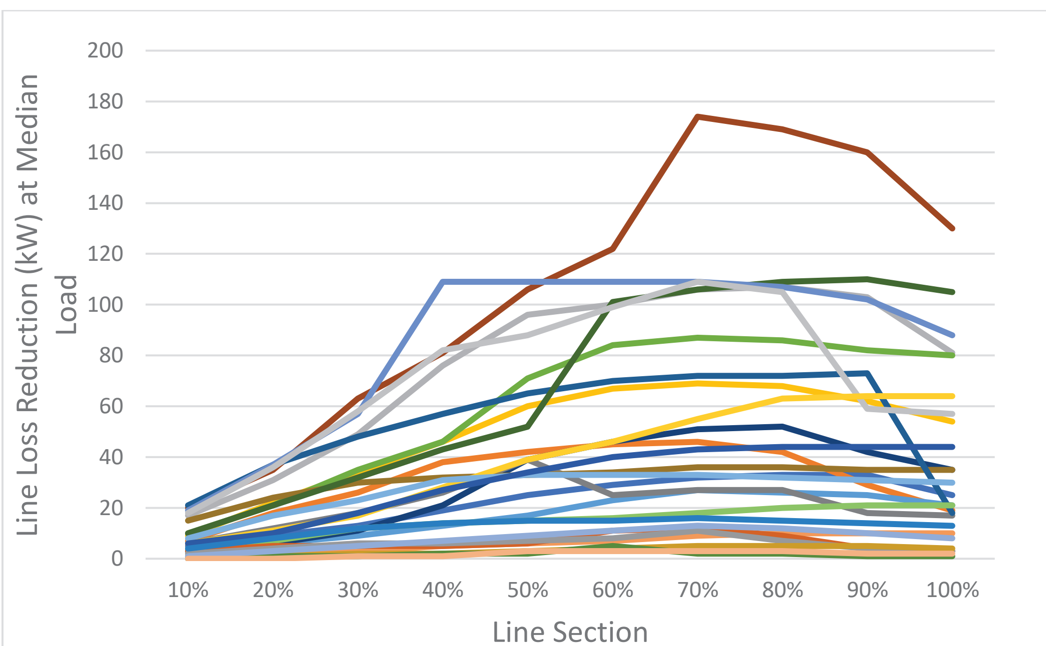
% Line Loss Reduction Relative to 1 MW Generator Nameplate



Individual Circuit kW Line Loss Reduction with 1 MW Generator at Median Load

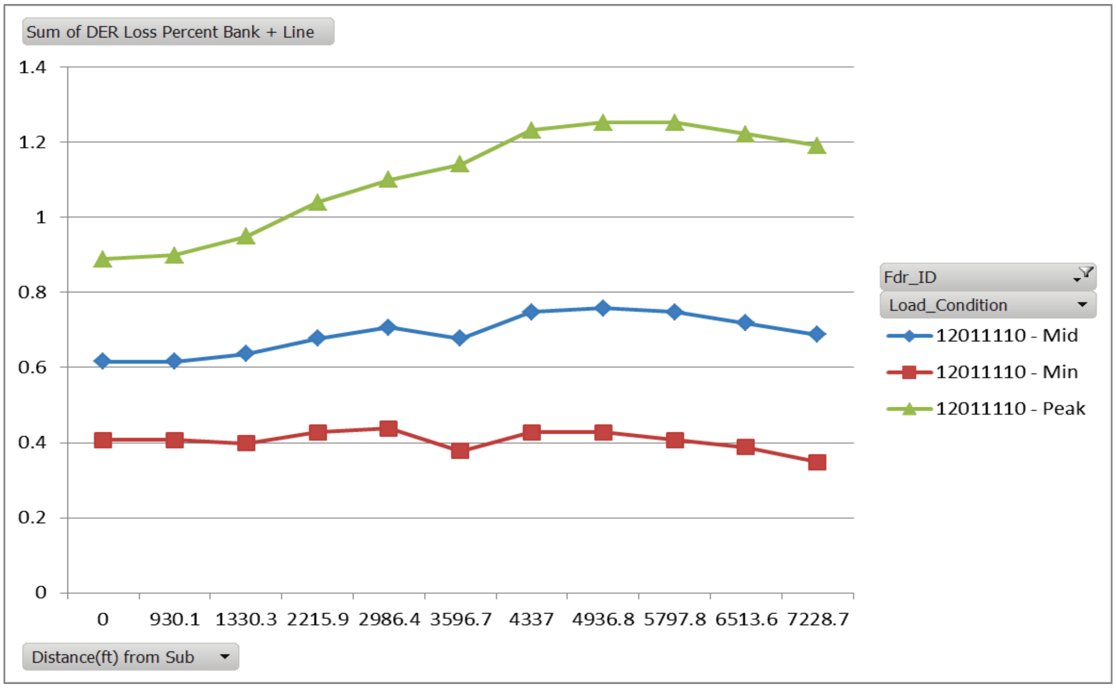


Individual Circuit kW Line Loss Reduction with 1 MW Generator at Peak Load

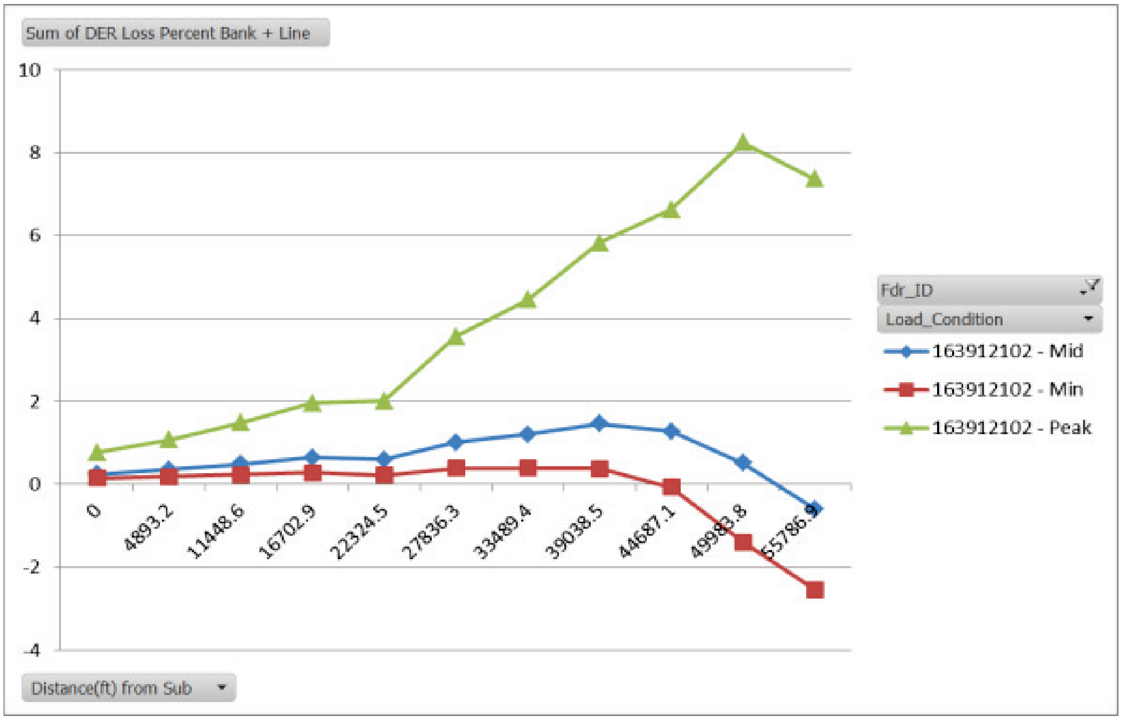


Pacific Gas & Electric

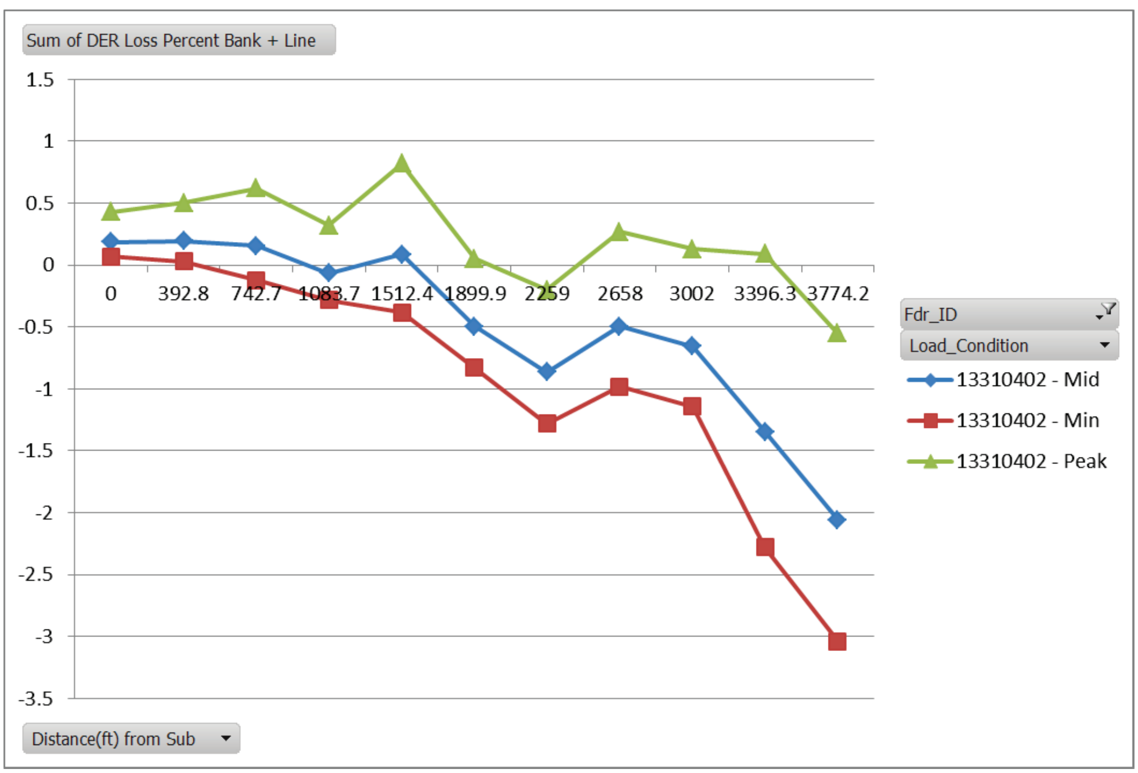
Loss Reductions as % of nameplate for 1 MW Generator on Representative Urban/Suburban Substation Circuit



Loss Reductions as % of nameplate for 1 MW Generator on Representative Rural Substation Circuit

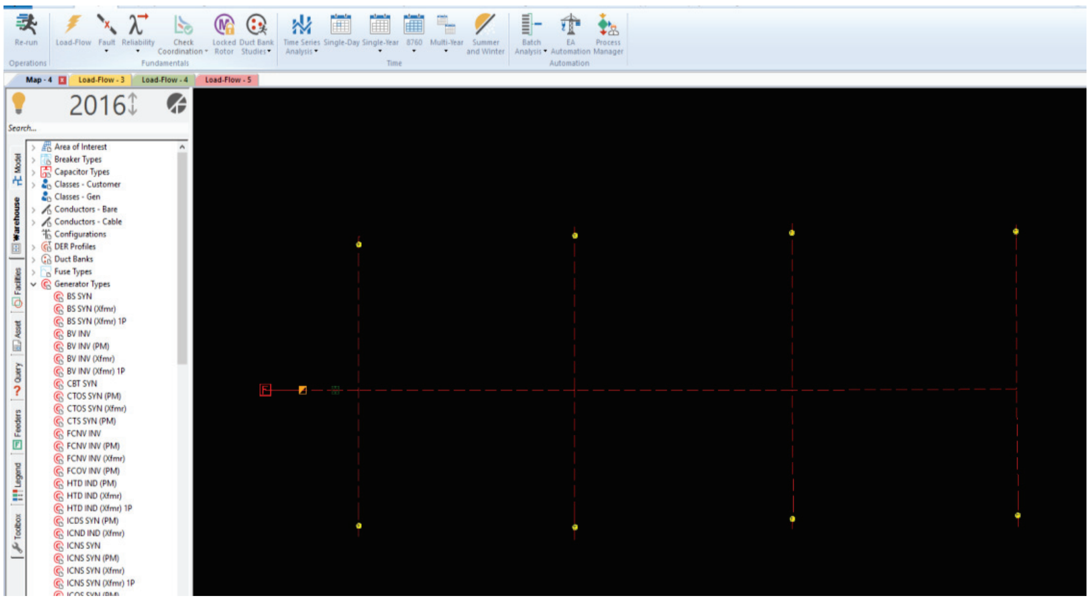


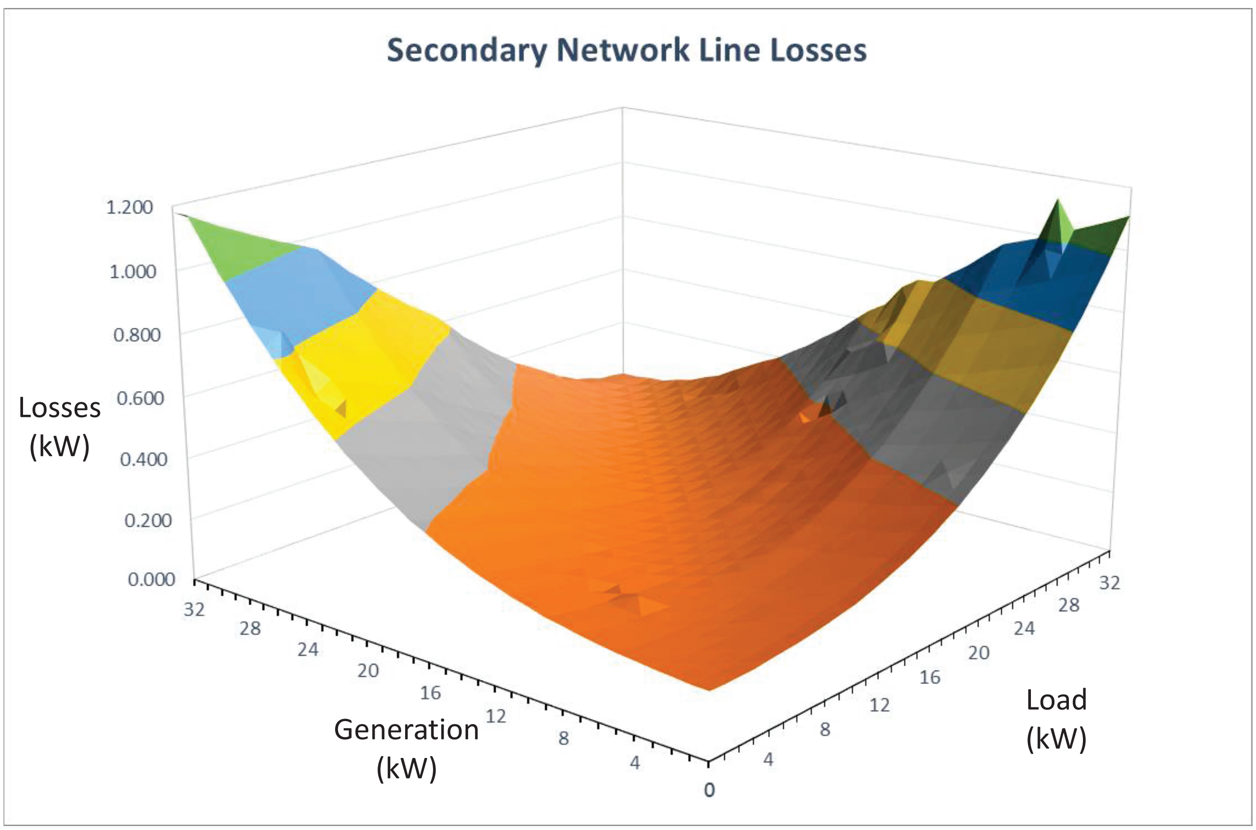
Loss Reductions as % of nameplate for 1 MW Generator on Representative Lightly-Loaded Circuit



Secondary System Losses Study

Model of Secondary Network with 8 Residences with Generators





Overall study Findings

- For 4 kV distribution lines, the amount of line losses was not significantly reduced when simulating a 1 MW generator at various locations.
- Adding 1 MW generator on 4kV circuit typically resulted in reverse power flow and increased line losses.
- When DER generators cause reverse power flow through the distribution service transformer or the substation transformer, the total distribution line loss benefit decreases, can reach zero, or negatively impact losses if DER generation exceeds the loading on the circuit it's interconnected.
- Rural feeders tend to be longer and higher impedance, and have more locations with high peak losses as well as overall variance in line losses to feed each line section.
- Back-feeding does cause losses to increase in certain locations on the primary distribution feeder.
- Urban feeders are typically stout, low impedance, short length, and have low losses so they are not highly location sensitive.

Losses on the secondary network are mainly derived from net transformer loading and will be minimal when generation is coincident and sized to match load (i.e. load is fed from generation locally).

Conclusion

- **For Cost Effectiveness Use Case in DERAC**
  - Maintain Status Quo in publicly available LNBA Calculator tool and DERAC calculators.
  - As DERAC becomes more granular, incorporate additional public loss factors corresponding to additional granularity (e.g. LCR-level transmission loss factors).
- **Deferral Framework Use Case**
  - Incorporate more locational differentiation of losses within the LNBA tool
  - Variation in losses can be significant for "outlier" locations (e.g. at a location with 25% losses at peak, a 800 kW generator can provide 1 MW load reduction at the transformer)
  - Evaluation approach will depend on number of deferral opportunities and associated circuits that pass through deferral screens TBD in track 3
    - If a small number of feeders, more detailed modeling could be feasible
    - If a large number of feeders, a clustering/representative feeder approach may be needed.
  - IOUs will incorporate one of the above approaches in the 2018 roll out of LNBA heat map and public tool

Item 5: Avoided Transmission Sub-Group

LNBA Working Group

Clean Coalition

Recap of Clean Coalition Avoided Transmission Valuation Proposal

We proposed and saw consensus on using the full lifetime TRR value of avoided transmission capital investment, as is consistent with utility practice elsewhere. However, we believe there should be further review of the discount rate applied to long-term avoided costs and benefits to ensure these are not undervalued.

We have proposed and demonstrated that DER can reduce the need for transmission investments for peak capacity, reliability, economic, and policy purposes.

Demonstrating that DER can reduce the need for transmission investments, we referenced by example PG&E's 2015 Distribution Resources Plan. This indicated that in 2014, PG&E's net peak demand in June, July, and August was approximately 17,600 MW after accounting for DER generation. Based PG&E's 2016 distributed generation (DG) forecast of 3,695 MW generation at peak hour, peak transmission load, and associated additional new transmission capacity needs, would have been 3,700MW (17%) higher in PG&E territory alone if not for the presence of distributed generation.

This means that the peak transmission load forecast used in the Transmission Planning Process was reduced by 17% as a result of Distributed Generation, and further reduced as a result of other DER – Energy Efficiency, Demand Response, and a minor quantity of Energy Storage.

Additionally, each of these factors has directly reduced the total MWhs of transmission sourced renewable energy required to meet RPS (Policy) requirements. California energy efficiency measures are elsewhere credited with reducing energy use by at least 50% per capita since 1974 relative to trajectory usage absent these measures, meaning that total associated transmission requirements would otherwise be more than double their current level.

We have also cited the ability of DER to meet Local Capacity Requirements for reliability, creating a cost-effective alternative to either transmission or conventional generation locally. (As such, the avoided transmission value should be the lesser of the avoided transmission or conventional generation alternative, including emission mitigation). This was established in CAISO modeling of energy storage alternatives to Oxnard's' Puente peaker facility and Goleta's Ellwood peaker facility, and Clean Coalition's more cost-effective PV+Storage alternative;[26] SCE's Orange County Preferred Resource

[26] http://www.clean-coalition.org/regulatory-filings/cec-proposing-a-cost-effective-solarstorage-alternative-to-puente-gas-plant/

Procurement program; and PG&E's recently proposed local distributed resources Oakland Reliability Proposal.[27]

We proposed as a starting point the per MWh valuation of TRR reduction achieved by DER consistent with the CAISO Transmission Access Charge, and provided a Transmission Impact Analysis model for calculating that value,[28] and shared the model initial results reflecting the impact profile of each DER category on both total load and peak load.

We support use of the system-wide marginal cost of transmission over average cost, as proposed by SEIA and utilities, and rely upon CAISO to provide the data from which this value would be developed. Likewise, we proposed and support locational variation factors to be applied to the default marginal cost value based on forecast regional transmission needs if DER growth did not occur. We support SCE's Nov 30 proposal for regional categorization by energy import or export.

Pacific Gas & Electric

A summary of PG&E's proposal is included in this report, and references the full proposal submitted Dec. 5, 2017, which may be found here:

San Diego Gas and Electric

A summary of SDG&E's proposal is included in this report, and references the full proposal submitted Dec. 5, 2017, which may be found here:

Solar Energy Industry Association

SEIA has participated actively in the sub-group on avoided bulk transmission costs. The mandate of this group has been to develop a methodology to fill a significant "hole" in the valuation of distributed energy resources (DERs) – the long-term avoided costs on the high voltage transmission system in California that will not be incurred as a result of the widespread deployment of DERs.

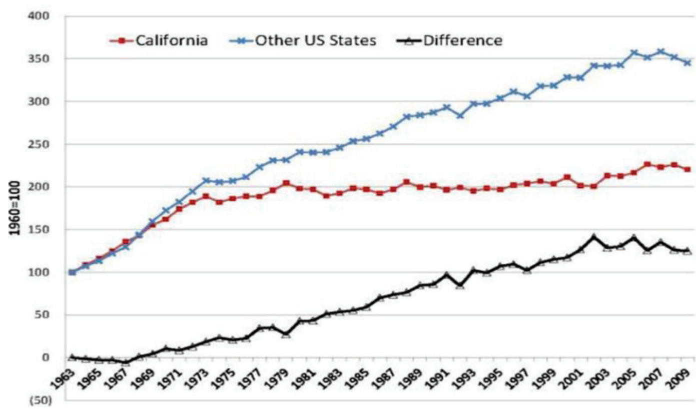
1. Avoided bulk CAISO-level transmission costs are not zero.

The bulk transmission costs that California utilities will avoid as a result of DERs are, by definition, counter-factual costs – they are costs that the utility will avoid, i.e. will never incur. They will be the costs for the transmission projects that utility planners drop during the planning process as no longer needed, or that they never have to plan in the first place because of the lower loads on the grid that result from DERs. As a result, these avoided costs typically will not be readily observable or publicly acknowledged. Despite the difficulty in observing these counterfactual costs directly, examples occasionally have emerged of major transmission projects on the CAISO grid that DERs have avoided. These examples include the 13 CAISO-level transmission projects that PG&E cancelled in 2016, saving

[27] https://www.caiso.com/Documents/Day2_PG_E-Presentation_2017-2018TransmissionPlanningProcess_PreliminaryReliabilityResults.pdf
[28] http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=21F0889F-3A84-4622-8F09-E8653BF3D02C

ratepayers $192 million,[29] and the Central Valley Power Connect project, costing between $115 and $145 million,[30] which may no longer be necessary largely as the result of DER development. There should be no doubt that avoided bulk transmission costs are non-zero and potentially of significant magnitude.

More broadly, California's distributed energy resources on the customer's side of the meter – principally, energy efficiency – have been responsible for avoiding transmission and distribution resources for decades. The reduction in electricity demand can be seen in the famous Rosenfeld Curve (see figure below), which shows that California has flattened its per capita electricity usage over the last four decades even as per capita electric consumption continued to grow in the rest of the United States. If California had followed the per capita demand trajectory of the rest of the U.S., electric demand in California would be more than 50% higher today.



This accomplishment has allowed California to avoid major investments in transmission and distribution infrastructure, including significant investments that have never appeared in the utility planning process as a result of the lower demand trajectory. Assessing the counterfactual, long-run transmission costs avoided by DERs is challenging, but is necessary to value accurately these long-lived resources on which California has and will rely to meet its energy needs.

2. Calculate avoided bulk CAISO-level transmission costs on both a system and locational basis.

There are two central challenges in developing a reasonable metric for avoided bulk transmission costs. The first is determining a long-term "system" avoided cost value that can be used over the full 25-year life of a long-lived DER such as on-site solar, when the transmission planning process extends at most 10 years into the future.[31] The second challenge is developing a way to include

[29] See http://www.fresnobee.com/news/local/article122063189.html.
[30] See https://www.greentechmedia.com/articles/read/Californians-Just-Saved-192-Million-Thanks-to-Efficiency-and-Rooftop-Solar.
[31] It is also not reasonable to use a value of zero as the long-term avoided costs for CAISO transmission simply because the FERC regulates CAISO-level transmission costs and calculating marginal CAISO costs is not part of the FERC ratemaking process.

more locational granularity into these avoided costs, to reflect most accurately how these avoided costs may vary across the CAISO grid.

To accomplish these two goals, we suggest starting at the simplest level – calculating distinct long-run avoided bulk transmission costs for each of the IOU service territories. This IOU-specific long-run avoided transmission cost should serve as the "system" value for use in the DERAC calculator for DER cost-effectiveness evaluations in that service territory.

To develop more granular, locational avoided costs, SEIA recommends that all interests – the Commission staff, the CAISO, the IOUs, DER providers, environmental groups, and ratepayer advocates – continue to work to refine the CAISO's transmission planning process (TPP). It is our understanding that the TPP is evolving to include consideration of DERs as non-wires alternatives to specific transmission projects that are planned to meet local resource adequacy needs in local reliability areas (LRAs). SEIA supports further work on the TPP so that there is an effective and transparent means for DERs to provide a reasonable alternative to specific upgrades of the bulk transmission system. The refinements to the TPP should include the explicit calculation and publication of the incremental transmission costs to meet specific local RA needs, with a meaningful opportunity for DERs to defer these transmission costs.

3. All transmission costs should be assumed to be deferrable by DERs.

SEIA's central concern with the calculation of marginal or avoided bulk transmission costs at the "system" level is the IOUs' assumption that a significant portion of the bulk transmission projects in their CAISO transmission plans cannot be deferred by DERs. It is SEIA's position that the calculation of marginal transmission costs should assume that all future transmission investments potentially are deferrable by DERs. Indeed, since the purpose of transmission is to transmit energy from where it is generated to where it is consumed, it is illogical to conclude that there is any transmission that could not be avoided by siting generation in the same location where the energy is consumed.

The CAISO has described four primary drivers of transmission investments:

- **Serve peak loads**, including existing and expected peak end-use demands;
- **Reliability**, such as preventing overloads under certain contingencies;
- **Economic** – for example, to reduce congestion costs; and
- **Policy-driven** transmission to access renewable resources.

As discussed below, DER deployment can avoid future transmission investments in all of these categories. As a result, all transmission investments should be included in calculating the transmission costs that are avoidable by DERs.

Load growth. DERs serve or reduce peak loads at the sites where they are located, or export power that serves the peak demands of nearby customers on the distribution system.[32] Accordingly, DERs can reduce load growth, and defer or avoid transmission investments needed to serve load growth. We observe that, even if loads are not growing, transmission projects whose principal purpose is to replace existing transmission facilities (with no increase in system capacity) can be considered marginal investments if they are needed to keep system capacity from declining. Thus, even projects that replace existing transmission facilities should be considered in calculating marginal transmission costs.

Reliability. Transmission investments can be driven by a need to upgrade circuits or substations to avoid overloads that are modeled to occur during certain contingencies, such as the loss of a transmission line. These contingencies typically occur during times of high flows on the transmission system, that is, during times of high demand. DERs can reduce the loads that cause these reliability issues. There can be circumstances in which DERs can increase flows at the transmission level – for example, DERs located along a major radial transmission line that is moving power downstream to a load center can have the effect of increasing downstream flows on that line. However, as illustrated in SCE's presentation of November 30, 2017, those areas typically constitute just a small portion of the utility's loads.[33]

Economic. Some transmission projects are designed to reduce congestion on the transmission system, and thus are justified as reducing market costs for electricity. Congestion occurs when a line serving a load center reaches capacity, forcing the dispatch of higher-cost units serving the load center to prevent the line from overloading. DERs located within the load center can reduce the frequency and magnitude of such congestion by supplying additional power downstream from the constraint.

Policy-driven. The state's DER and Renewable Portfolio Standard (RPS) programs have long proceeded in parallel, with both programs resulting in the construction of significant new renewable generation. Today, it is clear that the state needs both programs to reach its long-term goals to reduce GHG emissions. The fact is that if there were no DER programs, the state would need (1) to replace the lost DG output and (2) to serve the higher end use load on a one-for-one basis with more utility-scale renewable power through the RPS program, in order to maintain the same overall penetration of renewable generation on the California grid and to maintain progress toward the state's GHG goals. This additional RPS generation would require significant additional investment in bulk transmission to deliver the power to the state's load centers. Thus, California's active encouragement and reliance on DERs as a key strategy for reducing carbon emissions in the electric sector show that DERs clearly avoid the need for RPS-related transmission investments.

Finally, it is important to recognize that the transmission system is a network, and a transmission project built principally for one of the above purposes may also provide benefits in the

[32] Some DERs, such as solar DG, do not reduce peak demands by 100% of their nameplate capacity. However, there are well established methods to calculate the effectiveness of DERs at reducing peak demands, such as effective load carrying capacity (ELCC) or peak capacity allocation factor (PCAF) methodologies.
[33] *See* SCE's presentation of November 30, 2017, at Slides 5 and 6, showing just 3% of its service territory (the "Outer Rural" area) has a negative impact on avoiding bulk transmission costs.

other categories. For example, a line built to access new renewable generation may have secondary benefits of reducing congestion and providing capacity to serve future load growth. The networked nature of the high-voltage grid argues for considering all transmission investments in the calculation of the marginal transmission costs that DERs can avoid.

4. Recommended regression method to calculate long-run avoided CAISO transmission costs at the system level.

The Commission already uses calculations of long-run marginal costs for sub-transmission and distribution at the system level as foundational inputs into cost allocation and rate design. These system-level marginal costs also have been used in the NEM 2.0 Public tool and in the DERAC calculator, for use in cost-effectiveness evaluations of DERs. IOU GRCs have calculated marginal costs for CAISO-controlled transmission,[34] as have other studies of distributed solar,[35] although the use of these values in CPUC ratemaking has been limited.

One well-developed approach to calculating long-run marginal costs at the system level is the National Economic Research Associates' (NERA) regression methodology that California utilities often employ to calculate marginal sub-transmission and distribution costs. This approach regresses at least 15 years of cumulative investment data (typically, 10 years of historical data and five years of forecasted data) against cumulative load growth, then converts the resulting marginal investment cost into a levelized revenue requirement. This approach has the benefit of using the regression to separate the portion of transmission investments that are peak-load-related from those that are not. As SEIA has discussed above, at least three of the four primary drivers of transmission investments (peak load growth, reliability, and economics) are directly or closely tied to peak demands on the grid, and all types of additions to the networked grid may contribute to serving peak demands. Accordingly, this method should be applied to all of an IOU's CAISO-level transmission investments, without assuming that any investments are "non-deferrable" by DERs.

SEIA has used this method to calculate marginal CAISO transmission costs for PG&E alone, based on PG&E's historical investments and the forecasted 2017-2021 investments in its 2016 CAISO-approved transmission plan. For the reasons discussed above, SEIA has included all of PG&E's planned future investments in this calculation. The result is a marginal transmission cost of $54 per kW-year over the 2007-2021 period, shown in the following figure. This result is similar to the $59 per kW-year for marginal CAISO-level transmission costs that SCE has used in its recent Phase 2 cases.

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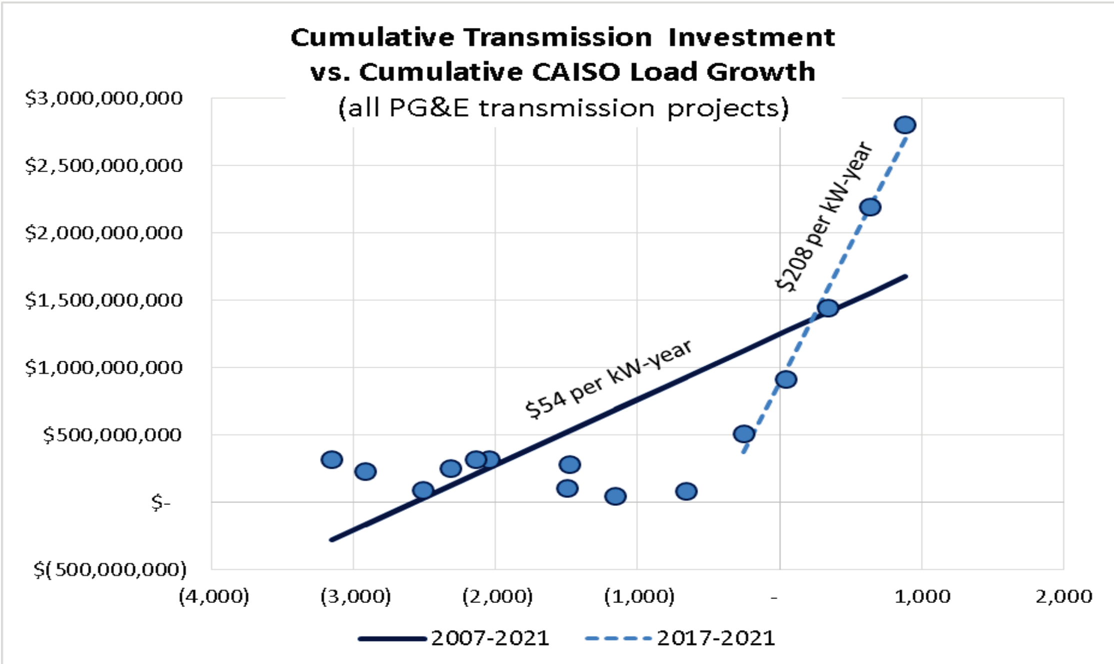
34 SCE's recent GRC Phase 2 cases (A. 17-06-030 and A. 11-06-007) have included a marginal cost for CAISO-controlled transmission of $59.18 per kW-year. See A.17-06-030, SCE Workpapers, "MCCR" sheet, "Input Sheet" tab, cell D22. In the A. 11-06-007 workpapers, see "MCCR" sheet, "Input Sheet" tab, cell D17.

35 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.



SEIA recognizes that there are several issues with this methodology that are likely to require further refinement, including more data from the IOUs. For example, the slope of the regression line in the above figure is moderated by the many recent historical years with relatively modest historical transmission additions and declining loads. This may be due to the impacts of PG&E's declining loads during and for many years after the Great Recession of 2008. The fit of the regression may be improved through the use of the planned capacity in historical years, rather than the actual peak loads.[36] Utilities plan transmission investments to serve their planning loads, which can differ from the loads actually experienced. PG&E's historical investment data also may not include all of its CAISO-level transmission plant, as PG&E apparently does not consider much of its recent transmission additions to be load-related. The figure also shows that the PG&E 2017-2021 forecast data supports a much higher marginal transmission cost of $208 per kW-year (dashed line), suggesting that this approach is, if anything, conservative on the low side.

As a variation on the method proposed above, the avoided CAISO transmission cost could be divided into two components: (1) the marginal cost per kW of peak demand for all transmission investments related to load growth, reliability, or economics and (2) the marginal cost per kWh of transmission built to access RPS resources. The first component would use the NERA regression method discussed above, but limited to transmission investments related to load growth, reliability, or economics as a function of planned peak capacity. The second component would be a separate calculation of the marginal cost of RPS-related transmission, with kilowatt-hours as the driver because the RPS goal is based on kWh sales. In this calculation, renewable generation from DERs would be assumed to displace RPS generation on a kWh-for-kWh basis, because both contribute equally to

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[36] SCE has used planned capacity instead of recorded loads in its NERA regressions in its recent Phase 2 cases "to minimize cost-to-growth distortions." A. 17-06-030, SCE 2018 GRC Phase 2 Workshop presentation (November 2, 2017), at Slide 27.

meeting the state's long-term carbon reduction goals. DERs that simply reduce loads (such as energy efficiency measures) would be assumed to avoid marginal RPS transmission costs by the kWh saved times the applicable RPS percentage-of-sales requirement.

5. Using the TPP for more locational granularity in avoided transmission costs.

SEIA recommends that the Commission's first priority should be the calculation of system-level marginal CAISO transmission costs, for the use cases such as the DERAC calculator that require such values.

The second priority after calculating system-level values is to develop more locational granularity in avoided transmission costs. To accomplish this, SEIA supports leveraging the existing TPP to calculate locational values based on the transmission investments needed to serve specific local areas. For example, the CAISO developed transmission alternatives to resolve capacity deficits in the western Los Angeles Basin resulting from the retirement of coastal once-through-cooling power plants and the SONGS nuclear units. These transmission investments provided cost benchmarks against which to evaluate generation alternatives in the western L.A. Basin LRA, including DERs and other preferred resources. Thus, the locational value of transmission in a specific LRA would be the cost to meet identified transmission needs to serve that area in the utility's CAISO-approved transmission plan. This would be similar to the process to identify locational values based on the utility's Distribution Resource Plan.

The locational avoidable transmission costs identified through the TPP can be used as the benchmark for competitive RFOs for DERs to replace the identified marginal transmission upgrades. This is what SCE and SDG&E did to procure capacity needed to replace SONGS, and what PG&E announced today it will do as an alternative to the transmission upgrades that would be needed once the aging peakers in downtown Oakland are retired.[37] Locational avoidable transmission costs also can be the basis for new DER tariffs that provide compensation to encourage DERs to be sited in locations where they provide net benefits to ratepayers that are greater than system avoided transmission costs, but less than the higher locational marginal transmission cost in that location.

Southern California Edison

A summary of SCE's proposal is included in this report, and references the full proposal submitted Dec. 5, 2017, which may be found here:

The Utility Reform Network

Introduction

TURN appreciates the work conducted by the avoided transmission cost working group (WG) over the last several months. There has been meaningful progress primarily in framing what the issues *are*, but

[37] See http://www.sfchronicle.com/business/article/Proposal-to-go-solar-at-old-Oakland-power-plant-12408069.php?cmpid=gsa-sfgate-result.

little in the way of deeper analysis. For example, there has been virtually no use of historical or forecast data to better understand fundamental issues regarding transmission projects that DERs can or will actually defer. This limits the factual basis on which TURN and other stakeholders have to rely for a very complex topic, and TURN believes that additional fact-finding is necessary to incorporate any type of meaningful value into the DERAC tool that actually improves upon the existing methodology.[38] TURN presents recommendations regarding next steps and TURN's avoided transmission cost proposal in the ensuing sections.

Additional Fact Finding and Coordination with CAISO is Necessary

TURN plans on responding to other stakeholder proposals to supplement the record. However, as noted there is a paucity of information and facts on which the Commission can rely in making its decision on how to develop more granular avoided transmission cost values. Rather than arbitrarily picking methodologies and numbers, the Commission must rely on some record evidence. TURN suggests two possible paths.

First, the Commission could order a study be performed by an outside consultant, with input from the utilities, to address basic gaps in knowledge. Such a study should include at a minimum discussion and explanation on the following issues:

- The types of transmission projects that can reasonably be deferred by DERs (including discussion of proper deferral screens);
- The types and value associated with transmission projects that have been deferred by DERs historically (and the accompanying value to ratepayers);
- How each DER's load/generation profile affects transmission projects (or not).

Alternatively, the Commission could set a procedural schedule for litigation that includes expert testimonies and evidentiary hearings to determine a methodology for transmission avoided costs.

TURN recommends the CPUC coordinate with CAISO to develop a process that would allow for the use of relevant and necessary CAISO data from the Transmission Planning Process to help address basic gaps in understanding or data.

In addition to a fact-finding process conducted through a study or litigation as discussed above, TURN recommends that the CPUC coordinate explicitly with the CAISO to ensure that any avoided cost value in the DERAC reflects a reality in which the CAISO actually defers transmission projects through procurement of DERs, better forecasting, and other mechanisms. Ratepayers would be harmed if the CPUC adopts a value for avoided transmission costs that does not in some way influence actual transmission planning and project construction.

TURN Avoided/Deferred Transmission Cost Proposal

[38] TURN notes that presently the DERAC does include a system-wide avoided transmission value based on each utility's marginal cost.

TURN provides an outline for an avoided transmission cost methodology below. It is based on the WG's discussions to-date and the following principles which TURN believes should help guide any ultimate implementation of an avoided transmission cost value:

1. All values must correspond to revenue requirement reductions for the IOUs and CAISO. Otherwise ratepayers may pay twice for the same project.
2. Forecast impacts from DERs that are intended to reduce transmission investments must flow through appropriate CPUC or CEC forecasts to impact CAISO TPP.
3. Values must be determined in an analytical fashion and be based in known fact.
4. Estimated avoided cost values should be for evaluation purposes only; actual payments to DERs should be based on competitive solicitations so that ratepayers have the opportunity to save money in comparison with business-as-usual.

TURN proposes a deferral value over the initial 10 year CAISO planning period based on the WG's discussions to-date. The annual CAISO transmission planning process ("TPP") should be the starting point for planned projects included in the avoided cost calculation. The values that form a basis for the transmission avoided cost should be updated annually and based on the following elements:

- Deferral values for DERs related to transmission projects planned due to load growth should be based on an understanding of the peak hourly demand of the project combined with expected peak hourly reduction from a given DER. For example, a resource that does not contribute to reducing peak load would not be awarded value for a particular project.
- Only projects identified by CAISO as potentially deferrable by DERs (generically any "non-wires" or "preferred resource" alternative) should be included in the avoided cost value. Projects should be removed if CAISO determines through the TPP that a non-wires alternative is not feasible. This includes the following two categories of projects:
    3) Transmission projects identified by the CAISO as *potentially* having a non-wires alternative;
    4) Transmission projects for which alternative proposals to deploy DERs are *received* by CAISO from an outside entity (PTO, DER provider, etc.).
- Deferral values should be locational in nature wherever possible, applying to an entire DLAP, sub-lap, or other area of granularity where a project is proposed to be built. In the future, the Commission should base locational values on load-flow models to determine where DERs have the most impact on reducing peak load for a given constraint. Existing load-flow exercises conducted in the TPP or for local capacity determinations may be leveraged to this end.
- A price cap on Local Reliability Areas marginal transmission costs could be set equal to the costs of generation alternatives, such as market prices for local Resource Adequacy capacity in each area or the CAISO's Capacity Procurement Mechanism price. A computation of the deferral value of new generation investment could also be applied as a price cap to ensure reasonable deferral value results.

- Computation of deferral values of avoided transmission investments should be computed using the “NERA Method” which the utilities now use to compute marginal transmission and distribution costs for rate design purposes.

TURN notes the above proposal is just for “planned” transmission projects. The category of “unplanned” projects encompasses two categories of projects – 1) those that would have been planned if not for forecast DERs and 2) projects outside of the ten year planning period. For the latter, TURN believes the current (IOU or system-level) marginal cost values in the DERAC calculator should continue to be utilized. For the former, TURN will respond at the appropriate time to IOU proposals. TURN reserves the right to modify its proposal at a later stage of this proceeding

Topic 2.iii-VAR Profiles: Improve spreadsheet tool by allowing hourly VAR profiles to be input

Joint IOUs' Initial Proposal
LNBA Working Group

Summary of Proposal

6. The Joint IOUs (SCE, SDG&E, and PG&E) propose to collapse item 2.iii (VAR profiles) under item B (location-specific smart inverter capabilities)
7. The IOUs propose additions to the LNBA tool to enable both users to input a DER VAR profile as well as a VAR requirements profile to validate that the DER VAR profile meets the requirements to defer a voltage project

Introduction and Background

7. Voltage support investments – generally capacitors or voltage regulators – are made on the distribution system where needed to maintain the voltage within Rule 2 requirements.
8. In order to defer a voltage project, a DER must be able to bring the voltage on the relevant distribution line section within Rule 2 requirements. This can be done by managing real power alone (e.g. using energy efficiency to help boost voltage) or using smart inverters to provide both real and reactive power support.

Discussion

9. The Joint IOUs (SCE, SDG&E, and PG&E) propose to collapse item 2.iii (VAR profiles) under item B (location-specific smart inverter capabilities).
   9.1. In general, a smart inverter is needed for a DER to provide reactive power; hence it makes sense to consider adding DERs' reactive power (VAR) capabilities to the LNBA tool as a subset of item B
   9.2. Additional smart inverter capabilities will be addressed after VAR profiles, since item 2.iii is a "priority item" while item B is not.
   9.3. When this proposal was discussed during the 7/15 and 8/15 WG meetings, WG participants expressed support for this suggestion; no WG member expressed opposition.

Proposal

3. Modify the LNBA Tool to accept a DER VAR Profile

3.1. This modification simply involves adding an hourly VAR profile along with the current hourly active power (kW) input. This is mocked up below.

DER Hourly Shape and Calculations

User Input for DER Hourly Shape				
PST Hour Starting	Month	Hour	DER at meter (kW)	DER at meter (VAR)
1/1/15 12:00 AM	1	0	0.00	0.00
1/1/15 1:00 AM	1	1	0.00	0.00
1/1/15 2:00 AM	1	2	0.00	0.00
1/1/15 3:00 AM	1	3	0.00	0.00
1/1/15 4:00 AM	1	4	0.00	0.00
1/1/15 5:00 AM	1	5	0.00	0.00
1/1/15 6:00 AM	1	6	0.00	0.00
1/1/15 7:00 AM	1	7	0.00	0.00
1/1/15 8:00 AM	1	8	105.30	105.30
1/1/15 9:00 AM	1	9	720.21	720.21
1/1/15 10:00 AM	1	10	154.16	154.16
1/1/15 11:00 AM	1	11	293.76	293.76

Fig 1.

4. **Modify the LNBA Tool to accept a VAR Requirements Profile**
   4.1. As with the real power requirements for reducing load to mitigate a thermal constraint and defer a capacity upgrade, a VAR requirement profile is needed for deferring voltage projects.
   4.2. The tool must simply be modified to accept a VAR requirements profile and to validate that the DER VAR profile input meets or exceeds this requirement profile, again analogous to real power for capacity project deferrals. This modification is mocked up below.

Area	**DPA 1**									
Threshold	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
	Load (kW)									
Date & time										

Area	**DPA 1**									
Threshold	-	-	-	-	-	-	-	-	-	-
	VAR (kVAR)									
Date & time (Hour Beg)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
1/1/13 0:00	-	-	-	-	-	-	-	-	-	-
1/1/13 1:00	-	-	-	-	-	-	-	-	-	-
1/1/13 2:00	-	-	-	-	-	-	-	-	-	-
1/1/13 3:00	-	-	-	-	-	-	-	-	-	-
1/1/13 4:00	-	-	-	-	-	-	-	-	-	-
1/1/13 5:00	-	-	-	-	19	19	19	25	25	25
1/1/13 6:00	-	-	-	-	19	19	19	30	30	30
1/1/13 7:00	-	-	-	-	19	19	19	30	30	30

Fig 2.

Conclusion and Next Steps

6. The IOUs must develop a methodology for calculating the hourly VAR requirement profile.

   6.1. The IOUs don't currently have all the tools required to do this, though they're currently in development as part of the ICA work
   6.2. At the same time, Rule 21 rules are currently in flux regarding reactive power requirements and power factor limits which would also influence the development of VAR profiles.
   6.3. DERs will always have both a real and reactive power contribution, and both real and reactive power have an impact on voltage. Hence assumptions for DERs' power factor are needed, and these will be impacted by Rule 21 requirements currently being considered.
7. Subsequent discussions will address additional smart inverter capabilities related to other grid services (e.g. CVR and situational awareness).

WG Report Item 7: Incorporate (Forecasting) Uncertainty Metric in LNBA Tool for Planned Deferrable Projects

Joint IOUs' Initial Proposal
LNBA Working Group

Note: in the June 7 ACR, Item 7 states: "Incorporate a (forecasting uncertainty metric in LNBA tool for planned deferrable projects." "Requires coordination with development of deferral screening criteria under development in the DRP Track 3 Sub-track 3."

Summary of Recommendations

1. All potentially deferrable projects that are a product of the IOU distribution planning process that pass the technical and timing deferral screens provided in the DIDF Energy Division Staff proposal will be evaluated in LNBA (pursuant to a final DRP Track 3 Sub-track 3 decision).
    a. The technical screen is based services DERs can provide identified in the IDER OIR
    b. The timing screen is based on the amount of time required for DERs to be deployed before the need date given existing procurement and interconnection processes and timelines.
2. Uncertainty metric is qualitative and will be utilized as one of the metrics to select the potentially deferrable projects that will be included in a future RFO for DER products/services
    a. IOUs will develop a process to rate DER deferrable projects' certainty in order to inform selection of projects to move forward to RFO with the greatest chance to be successfully deferred by DER.
3. IOUs will display a qualitative certainty metric rating for all projects included in the LNBA maps illustrating low, medium, and high certainty of the need staying in the year in which it's currently forecasted.

Introduction and Background

Currently the LNBA tool does not incorporate forecast uncertainty within the distribution need calculations or in the output calculations of the tool. Incorporating an uncertainty metric within the LNBA tool was a non-consensus item in the LNBA working group final report. The LNBA long term refinements working group will discuss how the deferral framework within DRP Track 3 addresses uncertainty and/or how such a value could be included in the LNBA tool and represented on a heat map.[39] The Assigned Commissioners Ruling on the Track 1 long term refinements identified this topic as a second tier item that is to be discussed after higher priority tier 1 topics.[40] At the third long term refinement LNBA working group meeting held on September 19, 2017, the Joint IOUs presented to the greater working group the recommendations for project certainty to be used as one of the prioritization metrics to select potentially deferrable projects to be included in an RFO for DER products/services and a qualitative certainty metric would be included on the LNBA maps. This aligns with the current expectations of DRP Track 3 Sub-Track 3 and meets the goals of the long term refinement item 7 - Incorporate (forecasting) uncertainty metric in LNBA tool for planned deferrable projects in the Assigned Commissioner's Ruling dated June 7, 2017.

Discussion

The "certainty" or "uncertainty" metric referenced in this topic relates specifically to forecasting and more precisely to the year in which a projected distribution need is forecasted to occur. Certainty in this context is not related to the feasibility of DERs successfully meeting the identified distribution need. The certainty metric should be used as one of the prioritization variables to select deferrable projects to move to RFO for DER procurement but should not be used to further screen out or remove projects that would otherwise be included in the LNBA. In this way, the LNBA will not be limited to the select number of projects in which DERs are actively being procured to defer. Projects that pass the existing assumed technical screen, based on services identified in the IDER OIR: Capacity, Volt/VAR, Reliability (Back-Tie), Resiliency (Microgrid), and the timing screen: the length of time to procure and install DER, will be included in the LNBA tool. If the screens are modified or expanded in future decisions the inclusion of projects within the LNBA would reflect those changes.

The total set of projects included in the LNBA will then be further prioritized for selection to be incorporated in a future RFO for DER products/services. A certainty metric will be applied within the prioritization process that will further screen out non desirable candidates for deferral. Certainty is a qualitative metric that relatives to the timing of the distribution need and load growth or generation project that is driving the need. Since forecasts are inherently uncertain, as forecasts look further into the future, distribution needs closer to present day are more certain and would be prioritized higher to be selected for RFO purposes. In addition, as customers become closer to completing construction (e.g., new building, solar farm) formal interconnection requests are received indicating those customers intend to actually connect and utilize the distribution system. Combining these qualitative assessments with how persistent and significant the capacity limits are exceeded in multiple planning cycle iterations allows the IOUs to make an assessment on how likely a distribution need is to occur in the year forecasted. The IOUs will utilize these metrics to rate the potentially deferrable projects to then move to the RFO process and also be reflected in the LNBA maps.

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[39] "Locational Net Benefits Analysis Working Group – Long Term Refinement Topics Scoping Document," More Than Smart, pg. 6.

[40] "Assigned Commissioner's Ruling Setting Scope and Schedule for Continued Long Term Refinement Discussions Pertaining to the Integration Capacity Analysis and Locational Net Benefits Analysis in Track One of the Distribution Resources Plan Proceeding," June 6, 2017, pg. 13.

The working group seemed to have consensus that the IOU proposals for application of the certainty metric is appropriate for the heat map use case and the distribution infrastructure deferral framework (DIDF) use case stated in the recent Track 1 LNBA and ICA short term issues Decision. However, consensus was not reached regarding how uncertainty of a traditional project can be further incorporated into the LNBA calculation. Certainty should not be incorporated into the LNBA calculation and only be used to prioritize which projects are selected for potential deferral through procurement of DER services. Distribution projects are developed by analyzing a forecast and comparing against equipment limitations. That being the case, the forecast used for distribution planning purposes should be as certain as possible to which distribution projects are created.

The third use case as part of the recent Track 1 Decision on LNBA and ICA short term issues indicates future iterations to the LNBA tool will be required to develop location-specific avoided T&D costs for input into the DERAC.[41] The Decision further explains expectations for the third use case referencing the need for IOUs to calculate the probability of unanticipated T&D projects up to a 30-year window and the necessity to determine grid needs and planned projects absent of the anticipated “autonomous growth” of DERs.[42] The Decision then illustrates the need for these types of analysis to enable DERAC to accurately inform DER tariffs and programs.[43] Concerns from the working group identified that if the LNBA will begin to inform DER tariffs and programs, that an uncertainty metric should be incorporated into the LNBA calculation. Ordering paragraph 15 requires the IOUs to file a proposal within 60 days containing methodological approaches to achieve the third use case referenced above.[44] Ordering paragraph 15 continues to reference the CPUC to solicit further stakeholder input and convene joint workshops to discuss proposals. Further discussion regarding forecast uncertainty metrics being incorporated into the LNBA calculation could be warranted if the CPUC issues a decision requiring the third use case referenced above to be achieved based on the requirements in the decision. If future discussion on forecast uncertainty inclusion in the LNBA calculation is to take place, it should occur during the workshops used to develop the third use case.

Conclusion and Next Steps

- LNBA will include all potentially deferrable projects that are output from the Distribution Planning Process
- IOUs will display the qualitative certainty metric (low, medium, high) as an additional LNBA map layer

[41] Decision on Track 1 Demonstration Projects A (integration Capacity Analysis) and B (Locational Net Benefits Analysis), Proposed Decision Rev 1, 9/28/2017 pg 46

[42] IBID. p. 48

[43] IBID, p.49

[44] IBID, p. 60

- Certainty will be applied as one of the prioritization metrics utilized to select the best project to move forward to the RFO process to procure DER for products/services

Further discussion regarding the incorporation of forecast uncertainty within the LNBA calculation could be warranted. The third use case directs further iterations of the LNBA tool for input into DERAC to inform future tariffs and programs, for which IOUs would submit a proposal. Future discussions on this subject should take place in workshops driven by the Track 1 ICA and LNBA Short term issues decision.

WG Report Item 11: Only Use Base DER Growth Scenario, not high growth scenario

Joint IOUs' Initial Proposal
LNBA Working Group

Summary of Recommendations

- LNBA should remain consistent with distribution planning process
- When Track 3 has addressed the issue, consider appropriate refinements to LNBA

Introduction and Background

Context in consideration of the Track 1 Decision

The Track 1 Decision also considers use of an additional forecasting scenario. However, as discussed below, this additional scenario is distinct from the use of scenarios under discussion in this item.

Long-term Refinement Item 11: use of High Growth Scenario

This item contemplates analyses of multiple DER scenarios of "expected" or "potential" outcomes. The purpose is to develop additional analysis and understanding regarding identifying *needs that are expected to occur*, and investments/solutions for those needs (whether conventional investments or DER solutions). The origin of this item is in Demo B where the IOUs were directed to use both a trajectory DER growth scenario and a "very high" DER growth scenario to develop two different versions of LNBA results. This topic is closely related to issues in Track 3 Sub-track 1. In particular, see the August 9 ACR, Issue #8: "How the high and low DER growth scenarios may be used in the Grid Needs Assessment."

Track 1 Decision: new counterfactual analysis to support 3rd use case

Conversely, the Track 1 Decision contemplates a counterfactual scenario, a baseline "no DER programs" scenario which is distinct from a planning forecast. The purpose is not to determine future needs and investments, but rather to understand "what would have happened" without existing DER programs, solely for purpose of cost-effectiveness analysis of those programs.

The Working Group Focus is on Item 11

As discussed above, there are two distinct questions with respect to Growth Scenarios:

1. Should LNBA incorporate multiple growth scenarios to analyze what needs/investments are expected?
2. Should LNBA incorporate a counterfactual "no programs" scenario?

The focus of this proposal and the long term refinement should be on first question discussing multiple growth scenarios and what needs/investments are produced from the scenarios. The second question on the counterfactual DER scenario is specific to a use case discussed in the Track 1 Decision, and is not currently captured in scope for the LNBA long term refinements Working Group.

Background on Item 11

For the IOUs Demo B, each IOU incorporated two distinct growth scenarios: a planning scenario consistent with the forecast used by IOUs for their distribution planning activities, and a very high scenario, representing the full implementation of a number of ambitious policy objectives, resulting in dramatic acceleration of growth for many DER types.) During the working group sessions, there was discussion concerning whether it makes sense to incorporate multiple growth scenarios in the LNBA, or whether it is more appropriate to use a single planning scenario.

The ACR included this topic as Item 11, and noted, "*May entail substantive discussion, but likely will not entail incremental methodology development; requires coordination with DER growth scenarios under development in DRP Track 3 Sub-track 1.*

The MTS scoping document summarized the topic as follows:

- *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 (load and DER forecasts) and vice versa.*
- *With additional information and knowledge gained through the conclusion of Demo B and the DER Growth Scenarios Working Group, are there possible methodological changes or alternatives to using the very high DER growth scenario that are within scope of the LNBA WG?*
- *What ongoing coordination needs to be developed between the LNBA WG and Track 1 Sub-track 1 of the DRP*?

Discussion

LNBA must remain consistent with distribution planning process.

LNBA is designed to estimate the value that that DER services may provide to the distribution grid. Such services can only offer value if they are meeting defined system needs to avoid IOU costs by deferring IOU investments. The IOU planning process determines needs for investment (whether met via conventional or DER projects). Consequently, LNBA results are meaningless if divorced from IOU distribution planning: Any values that are not based on the distribution planning process cannot be said to estimate the avoided of meeting grid needs, because those values no longer bear any relationship to actual planned investments: they no longer have a connection to IOU avoided costs.

Currently, IOU distribution investment plans uses a single forecast

IOU distribution planning uses a single forecast to identify grid needs and evaluation solutions to meet those needs. This may change in the future (as discussed in the next section). However, currently, IOU tools and resources, as well as policy, supports only a single forecast.

Growth Scenarios should be resolved in Track 3 before implemented in LNBA

This is an important, complicated topic that should be discussed, but not in multiple venues simultaneously. Track 3 ACR on Growth Scenarios explicitly includes multiple scenarios. (See issue #8: “How the high and low DER growth scenarios may be used in the Grid Needs Assessment”). The consideration of implementing growth scenarios into LNBA should be discussed following Track 3 determination regarding if/how/when the planning process should incorporate multiple growth scenarios. This discussion must consider the additional resources needed to evaluate multiple scenarios (e.g. enhancements to planning tools and substantial engineering effort) as well as questions of how to reconcile results under multiple scenarios in order to drive toward a single plan for implementation.

Conclusion and Next Steps

- LNBA should remain consistent with distribution planning process

When Track 3 has addressed the issue, consider appropriate refinements to LNBA

LNBA Item 8: Unplanned Grid Needs

CALSEIA response to IOU presentation
LNBA Working Group
October 27, 2017

Introduction

The LNBA Working Group is charged with quantifying the value of unplanned grid needs within the planning period and needs beyond the ten-year planning horizon. This was discussed at the October 16, 2017 Working Group meeting. The IOUs made a presentation at the meeting, but have not formulated a proposal.

Comments

The IOUs claim that, with the exception of large spot capacity needs such as establishing service for a new casino, all needed increases in capacity are long planned. They state, "the IOU load addition process is set up to have visibility of capacity needs long before they arise due to typical load growth."[45]

This may *not* be true for voltage-related projects. The IOUs need to share more information with the Working Group on how far in advance they typically identify specific voltage-related distribution upgrades.

For capacity projects, the relevant question is the pace with which they move from vague needs to completed projects. If a project is clearly identified and planned for construction 3-5 years in the future, utilities could run a DER solicitation to defer the project. However, this does not cover all of the benefits of DERs delaying upgrade needs.

If a project has been generally understood to be a probable future need for a long time but did not get defined into a planned project until less than three years before it is built, it missed the window for deferral solicitations. Incremental DER adoption in the affected area would still slow the need for project completion, but there would not be time for a solicitation for the purpose of pushing the project into a future planning year. Even if it is not officially pushed back by a year or more, delaying the urgency of a project has value in creating flexibility for engineering and construction resources.

More importantly, projects that are in the long-term plan will move more slowly toward getting better defined and specifically planned when DER adoption slows anticipated load growth. This is an obvious benefit of DERs and may be nearly universal. The need for upgrades develops more slowly due to DER adoption.

The challenge is how to measure these benefits. The ACR directs utilities to "Develop a methodology to quantify the likelihood of an unplanned grid need (deferrable project) emerging in a given location." The

[45] IOU presentation slides, LNBA Working Group meeting, October 16, 2017.

utilities have responded that the probability is so low that it is not worth calculating. Again, they argue that unplanned grid needs are not deferrable because they arise too quickly.

From a deferral solicitations perspective, this may be accurate. From a locational benefits perspective, this is the wrong question.

As the LNBA moves beyond creating tools for deferral solicitations to measuring locational benefits of DERs, it must take into account the benefits of:

- Delaying upgrades that have been generally identified but not specifically planned.
- Delaying upgrades beyond the 10-year planning horizon.
- Providing flexibility for upgrades under development.
- Deferring the need for voltage-related upgrades.

To measure the extent to which upgrades proceed erratically through the planning process, the utilities could make two calculations. First, determining how many constructed projects were in the planning process for less than ten years would give an indication of the portion of projects that were not candidates for deferral solicitations due to timing. Second, determining how many projects have remained in planning documents longer than ten years would give an indication of what portion of projects were delayed due to DER adoption and other changes in forecasted load growth.

During the October 16 Working Group meeting, the utilities stated that any such analysis would require too much investigation and would be difficult to do systematically. In absence of such a comprehensive analysis, the best way to calculate these benefits is by including distribution marginal costs in the value of incremental DER adoption.

WG Report Item 12: Asset Life Impacts: Explore Asset Life Extension/Reduction Value Provided by DERs

Joint IOUs' Initial Proposal
LNBA Working Group

Summary of Recommendations

1. The Joint IOUs propose to not include asset life impacts (either cost or benefit)
2. Wear and Tear and Thermal Degradation are two modes of failure that DER can impact, either positively (increasing asset life) or negatively (decreasing asset life)
3. Characterizing how DER interact with the physical mechanisms of wear and tear and thermal degradation is highly complex.
4. Recent work suggests that these impacts depend on many factors, are directionally ambiguous (i.e. can be positive or negative), and are small (especially so for already-lightly-loaded equipment).
5. Asset life impacts, as defined here, are distinct from avoided O&M or distribution capacity deferral, despite earlier work on distribution capacity deferral that involved evaluations of equipment thermal thresholds.
6. The Joint IOUs will continue to explore asset life impacts of DER, both positive and negative, and provide any findings that may warrant revisiting the issue in the future.

Introduction and Background

The June 2017 Assigned Commissioner Ruling includes Item 12: "Explore asset life extension/reduction value provided by DERs" in its list of Group 3 (i.e. lowest priority) items for the LNBA working group to explore. Item 12 is included in a list of items whose "value proposition is speculative and potentially low; working group should only address these issues if time permits."

The September 2017 DRP Track 1 Commission Decision; however, points to asset life extensions as a long-term LNBA refinement which could provide possible DER benefit that is not based on capital investment deferral. Based on this comment, it is appropriate for the WG to discuss this topic.

Distribution assets are removed from service for a variety of reasons:

1. Failure
    a. Manufacturing defects
    b. Environmental factors (e.g. corrosion, UV damage)
    c. Specific incidents (e.g. damaged by an impact)
    d. Wear and tear (moving parts are only designed for so many operations)
    e. Thermal Degradation (heat wave causes overloads and thermal break down)

2. Obsolescence
    a. Old design no longer considered safe or functional for current needs (e.g., live front equipment no longer considered safe)
3. Redeployment
    a. Transformers that are not at end-of-life that are replaced as part of a capacity upgrade are usually kept in stock and redeployed. (Note this is not a change in asset life, but an opportunity to defer installation of a new asset which is already captured in LNBA under the "distribution capacity" component.)

Wear and tear and thermal degradation are the only failure modes where DER could potentially have an impact, either positive (extending life) or negative (shortening life); hence DERs could only impact life for a subset of assets which are removed from service due to these modes of failure. While the physical bases for these two modes of failure are relatively well understood, the specific DER impacts are not fully characterized today.

The physical basis for wear and tear is fairly straightforward: devices that move, such as switches, wear down with each operation and eventually need to be replaced – hopefully not before they reach the cumulative number of operations that they're designed for. DERs' impact on the number of switching operations was examined in a 2015 California Solar Initiative funded study[46] which found that increased penetration of distribution-connected solar PV would likely cause an increase in Load Tap Changer (LTC) operations. This effect was found to increase expected LTC operations across five sample feeders, but with significant variability: sometimes causing hundreds of additional operations per day, and sometimes causing just a few increased operations. Another 2015 study of eight generic feeders by U.C. Berkeley researchers[47] found that PV had minor effects on in-line voltage regulator tap operations, with a minimal decline at lower penetrations and a more significant increase at higher penetrations. Voltage Regulators are typically designed to adjust their taps (switch) relative to load, therefore larger variability in loads downstream regulators will typically result in more operations.

The physical basis for thermal degradation is fairly well characterized for distribution transformers: prolonged exposure to high oil temperature (exacerbated by oil contamination with oxygen and/or water) causes paper insulation used in transformer windings to break down. A simplified model is used to develop a functional relationship between transformer life and oil temperature in the IEEE C57.154 "Standard for the Design, Testing, and Application of the Liquid Immersed Distribution, Power, and Regulating Transformers Using High-Temperature Insulation Systems and Operating and Elevated Temperatures" which is represented below for two different cooling oils.

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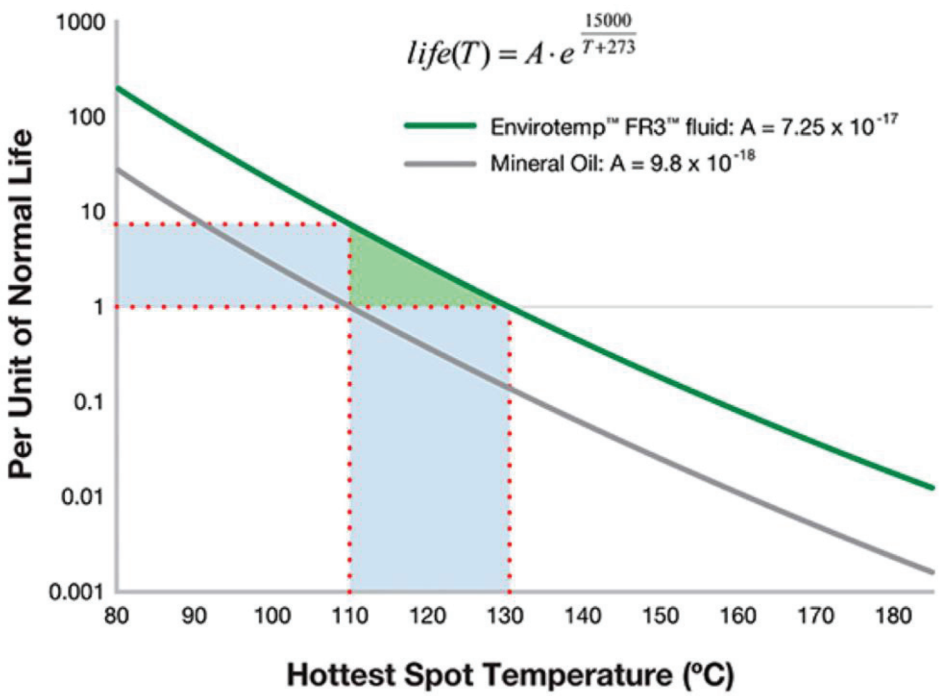
[46] Available here: http://calsolarresearch.ca.gov/images/stories/documents/Sol3_funded_proj_docs/UCSD/CSIRDD-Sol3_UCSD_TapOpsReduction_20151120.pdf

[47] Available here: https://arxiv.org/pdf/1506.06643.pdf



Note the logarithmic scale: for example consider a mineral oil filled transformer designed to have a 40 year life when under the design conditions of a constant hot spot temperature of 110C. If actually exposed to a constant hot spot temperature of 120C (10C above its intended temperature), a 5C reduction to 115C increases expected life from 15 to 24 years. If that same transformer is exposed to constant hot spot temperature of 100C (10C below its intended temperature), a 5C reduction to 95C increases expected life from 114 to 197 years. This suggests that the notion of lengthening expected life for transformers that are lightly loaded is dubious; other factors will surely require this transformer to be removed from service before 200 years are elapsed. Even if a transformer were in service for 100s of years, the present value of a life extension at this time scale would be de minimis due to discounting.[48]

Oil temperature is a function of loading level and duration as well as ambient weather conditions, and in theory DER can have an effect on oil temperature by changing the level and duration of loading on transformers; however this effect is complex given the interactions between oil temperature and the underlying load profile, the DER profile and the ambient weather conditions. The U.C. Berkeley study mentioned above also investigated PV effects on transformer asset life, finding that aging was generally unaffected by PV penetration, except for a few transformers that experienced a significant decrease in life due to overloads caused by backflow at moderate and high penetrations; however these devices would, in reality, have been replaced with a larger transformer.

[48] For example, a future benefit discounted at 7% for 100 years is reduced by over 99.8%

Other recent work by EPRI[49], that is broadly focused on DER distribution capacity benefit does attempt to evaluate impact of load profile adjustments on oil temperature, finding that overall effects on life are fairly small (measured in hours), are more significant when peak load hours can be targeted, and that effects diminish with increased PV due to limited overlap with peak hours. SCE is currently undertaking a study with EPRI that will evaluate the effect of energy storage on asset life and should be available by the end of the year.

Discussion

Asset life impacts of DER are often confused with Operations and Maintenance (O&M) and also with distribution capacity investment deferral.

DER asset life impacts, as described above, reduce or the likelihood of failure due to wear and tear or thermal degradation. In contrast, operations and maintenance tasks are routine servicing and testing of those same assets, including functional testing/exercising/inspecting of devices (e.g. switches, breakers, transformers, voltage regulators substation backup power supplies and fire suppression systems) and repairing or replacing devices (e.g. repositioning poles, guys, anchors, or cross arms, replacing broken insulators, and managing vegetation). The Joint IOUs do not believe that O&M activities can be reduced in frequency due to DERs, rather these activities are a necessary part of maintaining a functioning grid and are often driven compliance with laws governing electric utilities, such as California's General Order 95 to insure public safety.

Similarly, it is important to distinguish between asset life impacts and distribution capacity upgrade deferrals that are already captured in LNBA. Distribution planners endeavor to anticipate and avoid loading conditions which will exceed the conditions that a distribution asset is designed to withstand (i.e. conditions which exceed its normal and emergency ratings), the same conditions which would reduce the life of the asset. Planners typically seek to anticipate likely load growth that a transformer might experience such that the asset is sized so that it is not expected to experience any loading that shortens its normal lifetime or incur losses to point where a larger transformer would have been more cost effective.

If it ultimately a transformer does need to be removed from service due to load growth, it can be redeployed at a new location assuming it is still fit for service.[50] Distribution deferrals target such planned investments to upgrade distribution capacity. Earlier work in the 1990s[51] tended to describe

[49] Available Here: http://cired.net/publications/cired2015/papers/CIRED2015_1527_final.pdf

[50] Note that when an asset is replaced, if it is not obsolete or damaged, it is typically kept in stock and re-deployed.

[51] Other LNBA WG participants have referenced a 1993 study of a 0.5 MW PV system deferring a PG&E transformer upgrade (available here: https://pscdocs.utah.gov/electric/13docs/13035184/259136ExBEmailCommHopkins7-29-2014.pdf). This paper uses a distribution planning standard based on transformer oil temperature exceeding a certain level to determine how many years the transformer upgrade is deferred. Projected oil temperature is a distribution planning metric used previously by distribution planners at PG&E that was considered more precise than comparing peak load to rated capacity of the transformer at the time, but this paper still fundamentally

such DER capacity upgrade deferrals with analyses that used projected transformer oil temperature (derived using a load growth forecast) as the metric to determine when an asset was overloaded and needed to be upgraded rather than the conventional metric of asset loading. Either way, the effect is that an expected overload is pushed into the future to delay a capacity upgrade investment.

By virtue of the distribution system planning process and criteria, most assets should be exposed to conditions which are considerably below those that would cause damage. For most assets, therefore, marginal increases or decreases to asset loading are not material. As described earlier, other modes of failure or obsolescence will require asset replacement far before thermal degradation comes into play for assets that are exposed to normal conditions, and discounting would significantly diminish any benefit regardless.

Generally, assets are rated with a normal capacity rating and a higher emergency rating that can be sustained temporarily (i.e. for a limited number of hours) before significant thermal degradation affects the asset life. There are instances, however, when an asset IS exposed to those circumstances that cause loading to exceed the asset's design conditions. This can occur because load increases occurred which were not forecasted with sufficient time to develop and implement a solution or because of rare extreme weather conditions that exceed current system planning criteria.[52] Under such conditions, increases or decreases to loading can have a material impact on asset life if they align with the timing of these excessive loads. As discussed earlier, current research connecting DER to mitigating such conditions is inconclusive.

Conclusion and Next Steps

Based on the available material, the Joint IOUs propose that asset life impacts of DERs not be incorporated into LNBA at this time. As noted above, current research suggests that DERs' impacts on asset life – as distinguished from O&M and distribution capacity deferrals – are minor and ambiguous (i.e. could either increase or decrease asset life depending on the specific conditions). The Joint IOUs acknowledge that this is an active area of study, including current work with EPRI at SCE, and intend to provide further information if and when such information suggests that this topic needs to be revisited.

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evaluates a distribution capacity upgrade deferral. That is, a planning metric and threshold level is used to determine how many years into the future the expected overload can be delayed based on a load growth forecast. An analogy could be deferring an engine rebuild for a car. A typical metric one would use to estimate long the rebuild can be avoided might be based on the year in which it is expected to reach 100,000 miles, while a more precise estimate might be based derived from engine compression test results. Either way, the fundamental benefit being achieved is the same.

[52] For example, PG&E uses load forecasts based on 90th percentile weather conditions, which allows for a 1-in-10 chance that a given year will have weather that causes load to exceed the forecast, even if the load 90th percentile load forecast is perfect.

Item 4: Conservation Voltage Reduction

Tesla and SEIA Initial Proposal
LNBA Working Group

Summary of Recommendations

- SEIA and Tesla propose to create a locational value for Conservation Voltage Reduction(CVR) benefits that can be realized through the utilities' existing CVR schemes when DERs are available at the low-voltage customers on a distribution circuit, typically the end of a circuit.
- Since the 1970s, utilities have employed CVR programs that seek to reduce voltage flowing into distribution circuits where possible in order to conserve energy, reduce costs and avoid construction of generation capacity
- The degree to which voltages can be lowered is limited, however, by the lowest-voltage secondary line on the circuit.
- Deploying solar with smart inverters on buildings located on these lines can increase their voltage, which allows voltages to be lowered on the remainder of the circuit, which has an energy conservation effect
- Tesla and SEIA propose to calculate the CVR benefit in the form of reduced energy consumption and capacity reductions, much the same way benefits are quantified for other energy savings programs. The energy conservation benefit would be calculated by using a CVR factor to convert voltage reduction to energy savings using standard CVR factors for typical customer types on a circuit.

Introduction and Background[53]

As part of their core responsibilities, utilities must supply electricity to customers within established power quality standards. The range of allowable voltages (i.e. 114 to 126 V), an aspect of power quality, is set by American National Standards Institute (ANSI) standards. In practice, utilities over-supply voltage above the median 120v to most customers due to line losses that reduce voltage as electricity flows along distribution circuits. This over-supply of voltage results in excess energy consumption by customers.

To address this voltage delivery inefficiency, utilities are increasingly deploying conservation voltage reduction (CVR) programs. CVR is a demand reduction and energy efficiency technique that flattens and reduces distribution voltage profiles in order to achieve a corresponding reduction in energy consumption and greenhouse gas emissions. A 1% reduction in distribution service voltage can drive a

[53] The description of the benefits of CVR derived from solar and smart inverters described below include selected passages from a longer paper authored by Tesla/SolarCity: http://www.solarcity.com/company/distributed-energy-resources#

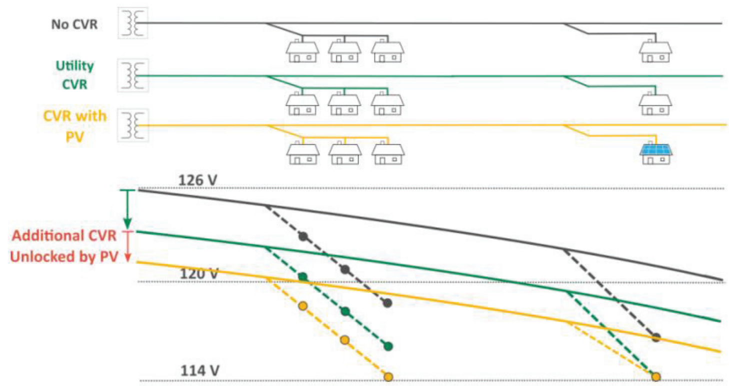
0.4% to 1% reduction in energy consumption.[54] CVR programs typically save 0.5 to 4% of energy consumption on individual circuits, and are often implemented on a large portion of a utility's distribution grid.

Distributed PV and smart inverters can enable greater savings from utility CVR programs because those programs typically only control utility-owned distribution voltage regulating equipment. Such utility equipment affects all customers downstream of any specific device; therefore, CVR benefits in practice are limited by the lowest customer voltage in any utility voltage regulation zone (often a portion of a distribution circuit) since dropping the voltage any further would violate ANSI voltage standards for that customer. Because distributed PV with smart inverters can increase or decrease the voltage at any individual customer location, these resources can be used to more granularly control customer voltages.

Typical distribution capacity planning studies do not consider the effects of the secondary distribution system, or secondary voltage drop – the portion of the distribution grid consisting of the power lines and pole top transformers that connect a customer's meter to the utility's primary distribution system.[55] However, incorporating these details is critical to capturing the technical potential of CVR since secondary voltage drop is a limiting factor for utility voltage reduction strategies today. Within a voltage regulation zone, if the lowest customer voltages on the secondary distribution system were to be increased by one volt, the entire voltage regulation zone could then be subsequently lowered another volt. Therefore, the benefit of addressing the secondary voltage drop is significant.

The CVR concept is demonstrated in the figure below, where three voltage profiles are shown along a typical distribution circuit, from substation to end customers. The solid lines depict the primary voltage drop, while the dashed lines represent the secondary voltage drop. The reduction in voltage between the gray and green lines represents the voltage reduction that can be achieved solely by controlling utility-owned voltage regulating equipment within a traditional CVR scheme. However, potential voltage reduction is limited by the customer voltage at the end of the line, which in this example is already at the lowest permissible voltage according to ANSI standards. By installing distributed PV with smart inverters at this customer site, the secondary voltage drop is decreased and voltage is subsequently increased, which is evident in the reduced slope of the secondary voltage drop. This allows the overall voltage profile in yellow to be further reduced, increasing efficiency savings.

[54] "Review on Implementation and Assessment of Conservation Voltage Reduction", Wang and Wang, IEEE Transactions on Power Systems, May 2014.
[55] "Evaluation of Conservation Voltage Reduction on a National Level", Schneider, Fuller, Tuffner, and Singh, Pacific Northwest National Laboratory (PNNL) for the US Department of Energy (DOE), July 2010



DERs control voltage locally and enable increased CVR benefits

Discussion and Methodology

The following methodology for determining the CVR benefits of distributed PV with smart inverters focuses on inverter contributions at the secondary (low voltage) level. This methodology quantifies the benefit from increasing the voltages of a subset of customers through targeted deployment of distributed PV with smart inverters in order to enable the subsequent decrease of voltages to all other customers on the circuit, resulting in energy efficiency savings. This methodology does not evaluate the incremental benefits to the primary (medium voltage) system due to the complexity introduced in modeling such benefits. Primary system benefits could be modeled if circuit model, equipment, and loading data were available.

Modeling Secondary Voltage Drop

Secondary voltage drop is a function of net load and the impedance of the service transformer and secondary line. To represent a typical secondary system, a simplified secondary model was utilized that consisted of typical pole top transformer, secondary conductor, and customer loads. For simplicity, all load is modeled as connected at a single location at the end of the secondary line. Consistent with the IEEE 8500-Node Test Feeder,[56] the secondary system, and therefore the impedance, consists of a 25 kVA transformer and 50 feet of 4/0 Al secondary conductor. The single line diagram of this typical secondary system is depicted in the figure below.

Single Line Diagram of a Typical Secondary System (All Voltages Referenced to Ground)

Equation 1 below shows how the secondary voltage drop is calculated, which is the difference of voltage magnitude between the primary side of the service transformer and the customer's meter. The voltage at the primary side of the transformer can be derived using the transformer load and secondary

[56] "The IEEE 8500-Node Test Feeder", Arritt and Dugan, Electric Power Research Institute (EPRI), 2010

impedance, as seen in Equation 2. The voltage at the meter is used as reference and is fixed to a nominal value, 120 ∠0° V, as shown in Equation 3. The difference in magnitudes between these two voltages equals the voltage drop across the secondary system (Equation 1).

$$VD = \left|V_{pri}\angle\theta_{pri}\right| - \left|V_{mtr}\angle\theta_{mtr}\right| \tag{1}$$

Where:

$$V_{pri}\angle\theta_{pri} = \overbrace{\left(I_{sec}\angle\theta_{sec}\right)}^{\text{Transformer Net Load}} * \overbrace{\left(Z_{xf}\angle\theta_{xf} + Z_{line}\angle\theta_{line}\right)}^{\text{Secondary Impedance}} + V_{mtr}\angle\theta_{mtr} \tag{2}$$

$$V_{mtr}\angle\theta_{mtr} = 120\angle 0°\, V \tag{3}$$

Modeling PV with Smart Inverter Capability

The voltage drop reduction of PV with smart inverters is a function of both the underlying PV generation as well as the reactive power capability of the smart inverter. Therefore, their combined impact on the secondary voltage drop must be modeled. To do so, PV production data from the National Renewable Energy Lab's (NREL) PVWatts® Calculator[57] is applied to an archetypal 5 kVA smart inverter. Inverter reactive power capability is activated for all hours of the day, but the smart inverter is assumed to maintain an active power priority because the economic value of active power is generally greater than reactive power (note: in geographies or times of day when reactive power is more valuable, this prioritization can be removed; this is actively being discussed in California). Therefore, the amount of reactive power available per inverter is limited by the coincident apparent power generation. For example, at night when the PV is not generating, the smart inverter is capable of supplying the full 5 kVAr. However, during peak PV generation, the smart inverter maynot be capable of supplying any VArs, depending on the size of the inverter and assuming an active power priority of the inverter. However, since both active and reactive power enable a reduction in secondary voltage drop, any combination of active and reactive power output provides benefits.

A negative secondary voltage drop (i.e. voltage rise) can occur due to reverse power flows from PV back-feeding onto the primary, or excessive reactive power support during low loading conditions. While voltage rises can occur in practice, overall CVR benefits would be limited by the customer with the next lowest voltage. Therefore, secondary voltage drops are assumed to be able to be reduced to zero, but no incremental benefits are attributed to voltage rises on the secondary.

Relating Voltage Reduction to Energy Reduction

Equation 4 details how the incremental CVR energy savings ($/kWh) are calculated for each voltage regulation zone.

[57] "NREL's PVWatts® Calculator", National Renewable Energy Lab (NREL), Accessed June 2016. http://pvwatts.nrel.gov

$$\left(\frac{\$}{kWh}\right)_{Energy} = \frac{\sum_{t=1}^{8760}\left[\frac{VD_{noPV}-VD_{PV}}{V_{Base}} CVR_f\left(1-\%_{Targeted}\right) E_{RegulationZone} C\right]}{E_{AnnualProducedByPV/Customer}\ \%_{Targeted}\ n_{TotalCustomers}} \tag{4}$$

The difference in the secondary voltage drop with and without PV (VDnoPV - VDPV) is calculated for each hour over the course of one year (8760 hours) using Equations 1-3 above. The change in voltage drop after PV is deployed is then converted to a percentage by dividing by the nominal voltage at the customer meter (i.e. 120 V).

The percent reduction in energy for a voltage regulation zone is then determined by multiplying the percent reduction in voltage by the relevant CVR factor. The CVR factor of a load is the change in energy that results from a corresponding change in voltage. For example, if a load has a CVR factor of one, then a 1% reduction in voltage would result in a 1% reduction in energy. A CVR factor of 0.8 has been found to be representative of typical distribution circuits.[58]

Percent reduction in energy for the entire circuit is then determined by multiplying the voltage drop and CVR factor by the percentage of customers that are having their voltage reduced. In this case, the customers who are experiencing the voltage reduction are those without PV installations (1 - %Targeted). Those customers with PV installations will receive the same voltage before and after the CVR scheme is in place, since the PV will raise their voltage while the CVR scheme will then lower it to its previous value. Equation 4 assumes that all customers have the same net load. In other words, 1% of customers consume 1% of the circuit load.

Quantifying Incremental CVR Benefits

After determining the percent reduction in energy, total financial savings in the numerator of Equation 4 are determined by multiplying the percent reduction in energy by the cost of energy in the voltage regulation zone. $/kWh benefits are calculated by dividing this number by the estimated annual energy production from all of the targeted systems. Equation 5 shows an annotated version of the energy benefits calculation highlighting where the change in voltage, reduction in energy, energy costs, and annual energy production are calculated.

$$\left(\frac{\$}{kWh}\right)_{Energy} = \frac{\sum_{t=1}^{8760}\left[\underbrace{\overbrace{\frac{VD_{noPV}-VD_{PV}}{V_{Base}}}^{\text{\% Change in Voltage}} * CVR_f\left(1-\%_{Targeted}\right)}_{\text{\% Reduction in Energy due to PV reducing voltage drop}} * \overbrace{E_{RegulationZone} C}^{\text{Utility CVR Energy Cost}}\right]}{\underbrace{E_{PV\_AnnualProducedByPVtion/Customer} * \%_{Targeted} * n_{TotalCustomers}}_{\text{Annual Energy Production of all Targeted PV Systems}}} \tag{5}$$

[58] "Green Circuit Distribution Efficiency Case Study", Electric Power Research Institute (EPRI), October 2010 PPPhttp://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001023518

After determining the savings attributed to energy, the savings attributed to capacity can be similarly found by taking the demand reduction at peak and multiplying it by the distribution marginal cost of capacity (DMC) as seen in Equation 6.

$$\left(\frac{\$}{kWh}\right)_{Capacity} = \frac{\left[\frac{VD_{noPV} - VD_{PV}}{V_{Base}} CVR_f \left(1 - \%_{Targeted}\right) P_{RegulationZone} DMC\right]_{At\ Peak\ Load}}{E_{AnnualProducedByPV/Customer}\ \%_{Targeted}\ n_{TotalCustomers}} \tag{6}$$

Total financial savings are determined by adding equations 5 and 6.

$$\left(\frac{\$}{kWh}\right)_{Total} = \left(\frac{\$}{kWh}\right)_{Energy} + \left(\frac{\$}{kWh}\right)_{Capacity}$$

Proposal

There are two potential means of accounting for CVR value in the context of the LNBA and DER Avoided Cost (DERAC) Calculators.

The first option is to represent CVR as a locational value for solar and smart inverter deployment on areas of distribution circuits with the lowest voltage. This value could be represented in the LNBA/ICA maps of the utilities' distribution grids. Value would be calculated by using the formulas above to compute the percentage voltage reduction made possible on a particular circuit by raising the voltage of the lowest-voltage secondary lines. This voltage reduction could then be converted to MWh of energy and MW of capacity saved using a CVR factor and equations 5 and 6 above.

Our understanding is that the utilities lack sufficient understanding of all of their secondary lines to develop this value on a locationally-specific CVR value across their distribution systems. This should not mean, however, that CVR is valued as zero. Thus, in addition to the first option, we propose an alternative method in which averaged CVR value could be integrated into the LNBA and included in instances where CVR is one of the benefits provided by DERs – for example, in the evaluation of a voltage management tariff developed in the Integrated Distributed Energy Resources proceeding.

Conclusion and Next Steps

Solar with smart inverters provide the opportunity for enhanced conservation voltage reduction, which is a powerful energy efficiency strategy for utilities. There are likely multiple ways where DER owners could be provided compensation for providing this service. What is key in the LNBA is to develop a value that ensures that such benefits are accounted for in instances where DERs used to provide CVR. A methodology is available for calculating this locationally, but should the utilities lack the data to calculate this on a locational basis an averaged value can be developed.

The next steps are:

- Create a system-wide CVR value based on an average CVR factor and the avoided energy values in the LNBA tool
- If utilities are able to better understand their secondary lines,, and those can be identified in the LNBA through the maps or spreadsheet tool, CVR should be incorporated as a locational value
- If utilities are not able to identify the low-voltage secondary lines, determine the average contribution of solar PV and smart inverters to CVR in utilities existing CVR programs

Item 4: Conservation Voltage Reduction

IOU Response Comments

LNBA Working Group

Introduction

Customers must be provided electrical service within an acceptable voltage range defined in each IOU's Rule 2. If service can be provided at the lower end of the acceptable range, certain end-use devices will consume less real power compared to service at the higher end of the acceptable range. The concept of seeking to provide service at the low end of the acceptable range in order to reduce energy consumption is referred to as Conservation Voltage Reduction (CVR). For purposes of evaluating costs and benefits, and performing cost-effectiveness analysis, CVR should be treated similar to any other energy efficiency measure. CVR is different from the "distribution voltage support" DER service, which is associated with avoiding a voltage-related investment by DERs deferring a voltage upgrade.

From the IOUs' perspective, the SEIA/Tesla proposal inappropriately proposes a simple system-wide value for CVR when this capability is clearly conditioned upon ability to deploy smart inverters in specific locations and quantities. Furthermore, the IOUs do not currently have the needed control capabilities to manage voltage-regulating equipment such that CVR could be enabled using distributed smart inverters. Finally, the proposal improperly suggests calculating CVR benefits that are based on customer bill savings rather than utility avoided cost and refers to a value for smart inverters providing CVR that is mostly attributable to a voltage optimization scheme rather than to the smart inverters themselves.[59] None of the IOUs has comprehensively implemented this voltage optimization scheme which is both necessary to enable smart inverters' ability to provide CVR and also which is responsible for the vast majority of energy savings from CVR.

Existing Conditions (i.e. without smart inverters)

At present, due to the electrical power flow from the substation to our customers on the circuits, generally the voltage reduces from the source substation towards the end of the line (EOL). When voltage is reduced below the required thresholds, the IOUs create mitigation actions to rectify the low

[59] The SEIA/Tesla proposal references this NREL study of one PG&E feeder: https://www.nrel.gov/docs/fy17osti/67296.pdf. The study finds that for this feeder, voltage optimization accounts for approx. 90% of the observed CVR benefit and smart inverters account for approximately 10%.

voltage conditions. Typically, depending on the severity of the voltage violation, the equipment used for mitigation includes the installation of capacitor banks or voltage regulators.

As such, the IOUs have implemented CVR to varying degrees across their service territories. These management schemes are typically based upon calculations of voltage at the end of line (EOL) customer using impedance data, voltage telemetry at capacitor banks, voltage telemetry at voltage regulators, and substation bus voltage. Through the use of AMI, the IOUs can gather data regarding the EOL voltage. If the voltage at the EOL is higher than anticipated, voltage at the substation bus can be lowered further~~,~~ and additional CVR energy savings can be realized assuming substation equipment is capable of making those adjustments.

Enabling CVR Benefits

At the LNBA working group on August 15, 2017, SIEA and Tesla stated that additional CVR energy savings could be enabled through smart inverters connected behind-the-meter if those systems are targeted to the right locations and if the voltage regulating devices on the circuit can be controlled to reduce voltage. This presentation did not discuss additional communication, sensing, or automation required to achieve CVR benefits through smart inverters connected behind the meter on distribution feeders. Specifically, the presenters stated that the only requirement to achieve CVR benefits through smart inverters is for the IOUs to lower the substation voltage. In turn, this would lower the voltage at the beginning of the distribution feeder allowing smart inverters further down the feeder to supply VARs and increase voltage potentially achieving CVR benefits.

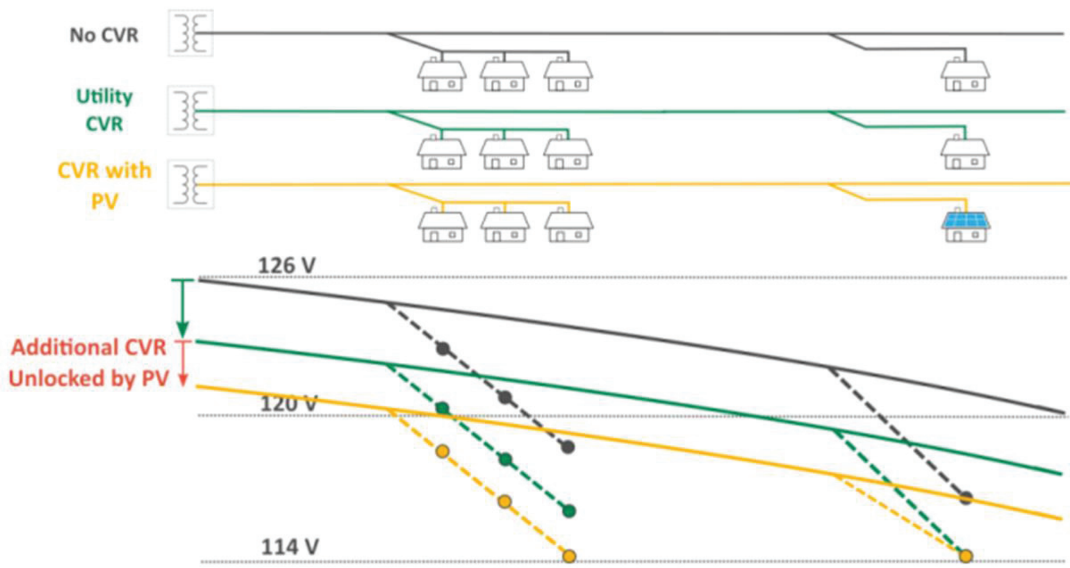
The IOUs do not agree that achieving CVR benefits from smart inverters is as simple as stated by Tesla and SEIA. Rather, upgrades to communication equipment, sensing, and control are required to optimize the smart inverters' capabilities to achieve CVR benefits. Specifically, strategic circuit configuration and communications / data systems are required for CVR benefits.

Fine-tuned controls are required to operate on the lowest possible edge of voltage limits, while serving all customers voltage within Rule 2 limits and realizing CVR benefits. If controls allow the voltage to increase too much, system-wide benefits are not realized. Without the specific conditions and requirements below, CVR through smart inverters will be inaccessible. IOUs and smart inverter providers need to collaborate to understand how to effectively implement CVR schemes into real world practice. Moreover, ongoing CVR studies at the IOUs will inform our understanding and quantification of CVR benefits.

Circuit Configuration Impacts CVR Benefits

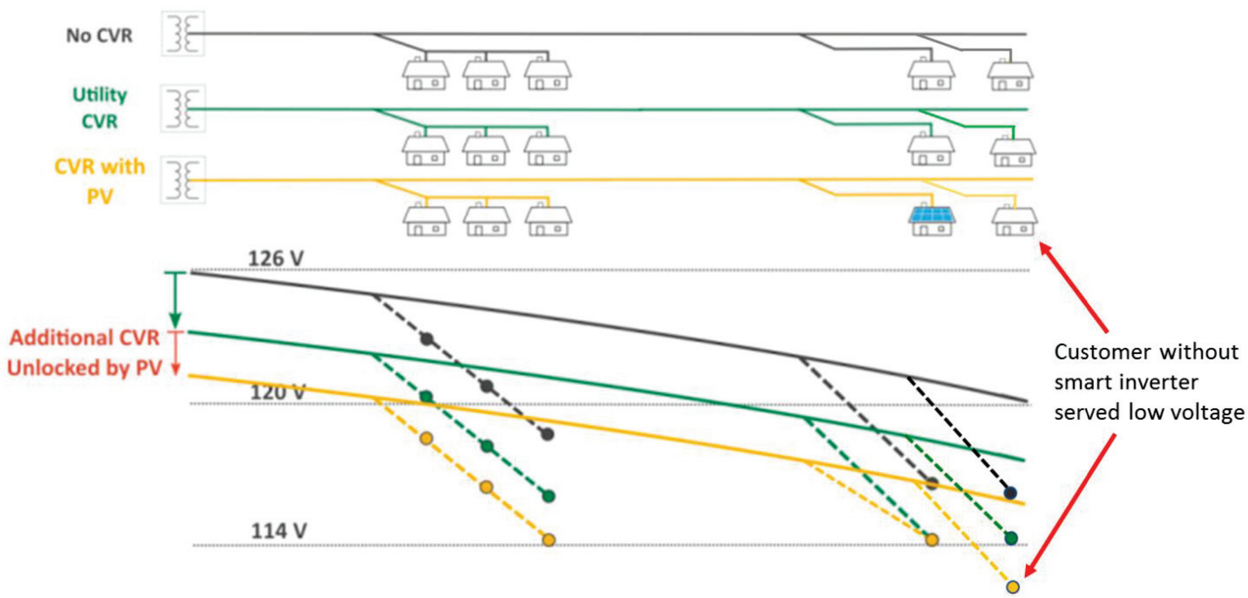
To potentially achieve CVR benefits, controlled VAR sources – both smart inverters and conventional sources – must be integrated into an overall CVR scheme, must be installed in strategic locations within the distribution feeders served from a single substation bus, and must be programmed based on locational CVR requirements. If the substation voltage is lowered without feeders equipped with controllable VAR resources at strategic locations on all the circuits integrated into a CVR scheme, there is an increased risk of serving high or low voltage to customers served from the same substation bus. This scenario could potentially result in customer equipment being damaged. The same concept holds true when attempting to lower voltage at the substation while only several customers on the circuit have the ability to increase voltage at their specific locations. The graph presented by SEIA/Tesla (Figure 1) depicts an idealized version of the potential impacts of lowering the substation voltage. Smart Inverters with the proper functions would have to be strategically installed at facilities on all the feeders from the substation and failing to do so would cause low voltage conditions. It is not as simple as installing one smart inverter to support the CVR smart inverter requirements as Figure 1 depicts.

Figure 1 – Image from SEIA Smart inverter Presentation



Specifically, this diagram (Figure 1) does not take account for customers downstream of the house with the ability to raise voltage at their location. In reality (Figure 2), if customers exist downstream of the same feeder, on unsupported bifurcated mainline, or on other feeders served out of the same substation without smart inverter functionality, these are at risk of being served high or low voltage.

Figure 2 – Customer without Smart Inverter Function Located at EOL Served Low Voltage



To implement CVR without the risk of serving low voltage to customers, all feeders connected to a substation need to be integrated in the CVR scheme and analyzed for voltage and loading impacts. Similarly, smart inverters would need to be strategically placed and programmed on all the feeders based on equipment and feeder characteristics to potentially achieve CVR benefits without detrimentally impacting customer voltage.

Communication and Data Systems are Necessary to Enable CVR

System-wide CVR benefits are unachievable in scenarios where smart inverters operate independently, without understanding the real time operations of the other smart inverters connected to the same substation bus. Centralized communication and control is essential to optimize the VAR production on the system to maintain required voltage levels. To calculate real time optimized smart inverter behavior, substation and feeder voltage data paired with smart inverter VAR production data must be transmitted to a centralized location. Distribution management systems would need the ability to send signals directly to smart inverters to inject or absorb VARs via Distributed Energy Resource Management System (DERMS) or Grid Management System (GMS). Due to the constant voltage changes throughout each day caused by the change in load, real time data acquisition and control is imperative. Moreover, the substation bus voltage and VAR sources must be dynamic. Additional communication and sensing equipment is required to achieve these functional capabilities. Without these capabilities smart inverters are blind to grid conditions that surround them unable to communicate with utility equipment and other neighboring smart inverters. These barriers would make it impossible to maintain the optimal voltage along a feeder to achieve CVR for customers.

Existing CVR Activities/Pilots Can Provide Insights

SCE is currently deploying a more "active" approach to CVR, called Distribution Volt/VAR Control (DVVC). The current deployment of DVVC is based off of a central control algorithm that was developed to control VAR producing equipment for applicable system configurations. Strategically placed capacitors on distribution feeders, combined with the centralized control algorithm and voltage sensing on distribution feeders and substations, enable DVVC to capture potential CVR benefits. To achieve CVR benefits, SCE has found that additional equipment must be deployed to enable the monitoring and control of all VAR sources connected to a single substation bus. This equipment is needed to optimize voltage levels throughout the distribution system. In addition, as part of SCE's Integrated Grid Project (IGP), SCE is examining software that can potentially calculate optimal VAR dispatch to minimize circuit voltage.

To quantify the benefits of different control algorithm schemes and system configurations, technical studies are needed to quantify the benefits of different CVR implementations versus non volt VAR optimizations. The IOUs are currently performing pilot studies to test the capabilities required to achieve CVR benefits.

LNBA Incorporation

The LNBA should incorporate real achievable avoided costs that DERs can provide. Considering the sensing and communication equipment required to implement CVR with smart inverters, the IOUs should continue the ongoing research to understand how to achieve this before incorporating CVR energy savings as a benefit within the LNBA. Realizing CVR through smart inverters with existing capabilities is not technically feasible for deployment or regular existing operations. In addition to studying the feasibility of utilizing smart inverters to maintain voltage at optimized levels, the actual calculated benefits of CVR should be further explored. It is currently very difficult to calculate actual recorded energy savings from the reduction in voltage. Before incorporating a benefit value related to CVR within the LNBA, the actual benefit of CVR needs more research and refinement.

It is important to note that CVR at its core is an energy efficiency measure. While we can all agree the pursuit off energy efficiency in the electric system is always warranted it is important to realize that the value streams generated by energy efficiency programs are mostly realized by individual customers and not ratepayers as a whole. As specific customers operate more efficiently through optimized voltage levels in CVR they will realize the financial benefit of having to pay for less kWh consumed. There is no energy cost change relative to the rest of ratepayers because even though the utility will have to procure less energy, the customers benefitting from CVR will pay an equivalent amount less in energy costs. Furthermore, as the customers pay for less kWh their overall contribution to T&D costs will decrease while no decrease in utility T&D investment may be realized, thereby increasing T&D cost relative to other ratepayers resulting in additional cost shift. As smart inverters are capable of implementing CVR locally for customers and these benefits are only realized by those customers, one could argue that the value of efficiency gains through CVR is already accounted for and can be marketed to customers directly.

Item 4: Conservation Voltage Reduction

TURN Response Comments to SEIA/Tesla Proposal

LNBA Working Group

TURN appreciates the information provided by Tesla and SEIA regarding the potential for avoided costs related to conservation voltage reduction (CVR) from solar systems. TURN's guiding principle for development of the LNBA is that any avoided cost (benefit) included in the tool must be actually captured by all ratepayers (or at least have a reasonable probability of doing so). The inclusion of a CVR benefit for DERs does not meet this basic premise because the benefit described by Tesla/SEIA is entirely theoretical; any avoided cost value for CVR ascribed to solar will not actually be avoided and accrue to ratepayers. The only way the LNBA tool can provide additional value over the status quo is if it maintains analytical rigor to include benefits that actually accrue to ratepayers; this is not the case with CVR due to distributed solar generation at this time.

While the information provided by Tesla and SEIA may provide a sound *theoretical* basis for CVR benefits, the provision of these benefits requires active utility involvement to lower voltages and subsequent monitoring and data collection to determine energy and peak load reductions. This is not being accomplished by California utilities today. Further, the basis for avoided cost values (e.g. the "CVR factor") suggested by Tesla/SEIA are not related to demonstrations of CVR with solar, but rather for general voltage reductions not related to solar distributed generation.[60] TURN is not aware of any demonstrations that prove the CVR benefits of solar claimed by the Tesla/SEIA.

Avoided energy and capacity benefits due to voltage reductions are complex, depending entirely on the circuit, loads on that particular circuit, and the timing of when voltage is actually lowered *compared with what would have otherwise occurred in the absence of a particular CVR program*. TURN's analysis of PG&E's volt-var optimization program ("VVO," akin to CVR) pilot program (which did not involve solar but rather additional sensors and controls to lower voltage) demonstrated that the utility did not accurately forecast energy reductions, such that larger energy reductions were expected than what was actually measured for almost every circuit included in the pilot (all but one).[61] TURN also found that the pilot was not "able to demonstrate…[an] ability to reduce demand during peak system hours. The absence of demand reductions over this period call into question whether capacity costs can be avoided."[62]

Similar issues may be found with integrating solar into a utility CVR program, complicated by the fact that benefits depend entirely on where solar is located on a circuit. Nevertheless, TURN hopes solar

[60] The parties cite to an EPRI study that examines the benefits of lowering voltages. EPRI, Green Circuits, https://www.epri.com/#/pages/product/000000000001023518/.
[61] A.15-09-001, *Testimony of Eric Borden Addressing PG&E Electric Distribution and New Business Expenditures*, April 29, 2016, p. 12.
[62] *Ibid,* p. 13.

developers can work with utilities (perhaps through an EPIC project) to implement and test CVR programs to demonstrate that lower voltages and related energy and peak demand reductions can be realized with distributed generation. Once such a program is developed and the concept and particular values demonstrated, an avoided cost value should be incorporated into the LNBA tool based on expected energy reductions from active utility involvement to lower voltages where solar DG is present.

WG Report Item 13: Situational Awareness: Explore Possible Value of Situational Awareness or Intelligence

Joint IOUs' Initial Proposal
LNBA Working Group

Summary of Proposal

Wherever IOUs have an incremental cost to attain data beyond that already required of DERs for a utility purpose, where the DERs themselves are able to provide and meet the requirements for the same specified data need, the DERs may be assigned the avoided cost value of deferring the incremental cost of acquiring the data in the utility's conventional manner.

Introduction and Background

1. **IDER Competitive Solicitation Framework Working Group (CSF WG) Final Report**
   The concept of a DER distribution service related to data for grid visibility and situational awareness emerged during the IDER CSF WG discussions; however no consensus on the definition or viability of this service was reached. The final report[63] only includes the following table listing an example and a related consensus item that this service would be associated with data that is not otherwise required.

Table 4: Additional Services

#	Additional Service	Description/example	Discussion
1	Grid visibility and situational intelligence	Measured conditions at the grid edge available second-by-second	Consensus additional service when data is not otherwise required
2	Reactive power support	Provided needed reactive power	Non-consensus. Disagreement over whether there is value beyond voltage regulation.
4	Conservation Voltage Reduction (CVR) benefits	Improved energy savings in a utility's CVR program due to smart inverters	Non-consensus. Definition of service may need to be developed further.

[63] http://drpwg.org/wp-content/uploads/2016/07/2016-08-01-CSFWG-Final-Report-Joint-Competitive-Solicitation-Framework-Working-Group.pdf

2. **June 7 Assigned Commissioner Ruling (ACR)**
   The June 7, 2017 ACR[64] states that "Value of data-as-service for situational intelligence is likely hard to quantify on avoided or marginal cost basis, and is driven to some degree by Commission policy on the use of DER data for grid operations and/or planning." The IOUs agree, especially with respect to dependence on commission policy related to smart inverter requirements.

Proposal

The IOUs propose to consider Situational Awareness as a service enabled by smart inverters and hence place this long-term refinement item under Item B in Group 1 of the June 7 ACR, "Methods for valuating location-specific grid services provided by advanced smart inverter capabilities."

The IOUs propose to define the Situational Awareness DER benefit as the provision to the utility distribution company (UDC) of grid information which is collected using DERs and which meets the following conditions: 1) the information meets a specified grid need for which the IOUs are planning an investment, 2) the information meets the data requirements as specified by the IOU (e.g. for data type, detail, frequency, location, voltage level, security, completeness, etc.), and 3) the information is not already required to be provided by the DER (e.g. as a requirement to interconnect).

The IOUs propose to value Situational Awareness DER services, as defined above, consistent with other distribution services. The value of this service is equal to the avoided RRQ of deferring the otherwise-needed capital investment calculated using the Real Economic Carrying Charge (RECC) method, or equal to the avoided RRQ associated with an expense that would otherwise be incurred to meet the same need.

In the absence of a defined need (i.e. the first condition is not met), there is no cost to be avoided, and thus no value attributed to the data from a DER. Similarly, if the information provided by the DER does not meet the IOU's needs (i.e. the second condition is not met), there is no avoided cost, and thus no value attributed to the data from DER. Finally, if data is already required for a DER to operate safely and reliably while connected to the distribution system or to receive incentives (i.e. the third condition is not met), additional compensation for that minimally-required data is not appropriate as there is no incremental value.

Key Questions Remain

Although the Joint IOUs proposal adds more detail to this DER service, key questions remain:

1. What data collection costs can be avoided by DERs?
   a. This is not a typical service today. It is not clear which of today's costs can be avoided, if any. For example, data from DERs may not provide sufficient coverage to meet needs: If an IOU has a need for information on conditions on the distribution primary system,

[64] http://drpwg.org/wp-content/uploads/2016/07/189819375_ACR_06.08.17.pdf

then customer-sited DERs on the secondary system are unlikely to be able to provide this.

2. Are there hidden costs of using DERs to provide grid data?
    a. For example, data from new SCADA devices are easily integrated into existing UDC systems and tools; integrating data from non-SCADA, third-party devices may require additional hardware or software investment that should be accounted for when evaluating the least-cost solution.
3. What are the minimum interconnection requirements for smart-inverter-based DERs?
    a. Some DERs (e.g. Large DG) are already required to have SCADA and generation meters to interconnect. At this time, the minimum requirements for smart-inverter-based DERs are still in development, including data-related requirements.
4. Should the DERs simply solicit and offer data services to utilities through normal market functions instead of being assessed as being of higher value in the LNBA because they have data? If DERS have data of value there is nothing preventing them from selling it to utilities as separate service.

WG Report Item 13: Data/Situational Awareness

SEIA Initial Proposal
LNBA Working Group

Summary of Recommendations

- Many distributed energy resources, such as rooftop solar panels and storage devices, are deployed with monitoring equipment and communications-enabled smart inverters
- Third-party DER providers can feed data into utilities' DERMS systems to:
  - Calculate gross load and more generally understand loading profiles
  - Identify faults for faster service restoration
  - Provide data at greater frequency than may be available through utility communications infrastructure
  - Provide nodal level data on power quality conditions
- SEIA proposes to calculate the value of situational awareness as the incremental cost of more frequent, customer-level data and provision of power quality information
- This value can be calculated as:
  - The avoided cost of additional bandwidth needed on wireless communication networks to backhaul data
  - Avoided cost of additional metering to measure on-site generation for calculating gross load
  - Reduced truck rolls from better fault location
  - Avoided cost of line sensors

Introduction and Background

Using smart inverters and other devices located at customer premises, third-party DER providers could provide data services and situational awareness for utilities that would normally install sensing and communications equipment for that purpose. The information most applicable to the larger distribution system is voltage and the occurrence of an outage (i.e. low voltage at a DER implies the possibility of low voltage somewhere else.). In providing voltage and outage information, DERs can provide functions similar to Advanced Metering Infrastructure, line sensors/fault detectors, and communication with line equipment, though only providing the monitoring function and not the control function.

In addition to voltage, frequency, and the occurrence of an outage, DERs can also provide loading information at each site. All of this information at the grid edge can be used to drive more effective smart grid programs, increase reliability, and increase grid utilization. Intelligence at the end of the line can be used to more efficiently operate the system. Power quality problems can be identified and troubleshot faster, outages can be detected faster, modeling accuracy can be improved, and distribution state estimation could be implemented.

Discussion and Methodology

In Phase I of the utilities' General Rate Cases, utilities propose investments in equipment that can provide improved awareness of real time electrical conditions on their distribution systems. For example, all three large utilities in California have deployed Advanced Metering Infrastructure (AMI) capable of providing voltage data, but the system typically only conveys billing-related data. This data is transmitted infrequently: the radio networks deployed by the utilities only backhaul voltage data and loading information once per day; outage data can be communicated within 5 – 15 minutes. As a result, the AMI system provides limited and infrequent data on loading and power quality. More frequent collection and communication of this data by DER systems could provide value at a lower cost than additional investments to the AMI system.

Other information utilities are proposing in their rate cases include systems for operating the distribution system. Utilities have proposed, in their GRCs, Advanced Distribution Management Systems (ADMS), Distributed Energy Resource Management Systems (DERMS), and Generation Management Systems (GMS) in order to improve analysis and control of grid operations. Some of these functions (i.e., DERMS) are needed for communication with DERS and DER aggregators to convey data that can provide situational awareness. Other equipment, such as the Generation Management Systems, may be unnecessary if reliability benefits can otherwise be achieved, in part by DER-provided situational awareness.

Finally, utilities have proposed deploying line sensors, fault indicators and smart switches. Investments in wireless networks with sufficient bandwidth are also needed to allow for more frequent communications and increasing data transfer with utility equipment and DERs. If additional sensors and fault indicators are unnecessary due to DER-provided situational awareness, that equipment can be avoided. If, as a result of the use of data from DERs there is no need to provide for additional bandwidth on utility communications systems that would be needed to convey data from- and commands to- line sensors, fault indicators, and switches that cost can be saved as well.

SEIA proposes to calculate the value of situational awareness as the avoided cost of sensors, metering infrastructure, software, network bandwidth and other equipment needed to provide the utilities situational awareness that would otherwise need to be deployed in the absence of DER equipment providing these services. The cost of this investment and corresponding magnitude of costs avoided can be estimated from utilities' General Rate Cases and AMI Applications.

In response to SEIA's presentation on this topic at the ICA/LNBA working group meeting on September 19, the utilities raised a number of concerns and questions. SEIA provides the following response to those questions and concerns:

- What data collection costs can be avoided by DERs?
  - <u>Utility concern</u>: This is not a typical service today. It is not clear which of today's costs can be avoided, if any. For example, data from DERs may not provide sufficient coverage to meet needs: If an IOU has a need for information on conditions on the distribution

primary system, then customer-sited DERs on the secondary system are unlikely to be able to provide this.

- SEIA Response: We agree that it is not a typical service today, but it is a service that adds value. Whether or not the utility is planning on implementing the cost is beside the point of having a value identified for such as service within the LNBA. The example provided on information needs on the primary versus secondary system is overly simplistic. Secondary data still adds value. Power quality on the secondary system can be used to inform what the power quality is in the primary system. Loading and generation data on the secondary system can be used to derive and inform loading and generation data on the primary system.

- Are there hidden costs of using DERs to provide grid data?
    - Utility Concern: Utilities believe there may be hidden costs. For example, data from new SCADA devices are easily integrated into existing UDC systems and tools; integrating data from non-SCADA, third-party devices may require additional hardware or software investment that should be accounted for when evaluating the least-cost solution.
    - SEIA Response: This is true, but it is also important to account for all of the data streams and use cases of non-SCADA equipment. What if implementation plans are already underway outside the situational awareness use case?
- What are the minimum interconnection requirements for smart-inverter-based DERs?
    - Utility concern: Some DERs (e.g. Large DG) are already required to have SCADA and generation meters to interconnect. At this time, the minimum requirements for smart-inverter-based DERs are still in development, including data-related requirements.
    - SEIA Response: This may be an incorrect interpretation of Rule 21. Section J repeatedly references that less intrusive and/or more cost effective options should be used. Unfortunately, the utilities often opt for the SCADA and generation meter approach, despite it being more expensive (This would be an example of another use case for non-SCADA equipment integration).

Conclusion and Next Steps

Distributed energy resources, such as rooftop solar, smart inverters and battery storage systems are increasingly being deployed with monitoring and communications equipment that are capable of providing to utilities situational awareness of conditions on their distribution systems at an incremental cost that could be significantly lower than the cost of equipment deployed by utilities solely for that purpose. The LNBA working group could calculate the value of that service by collecting and analyzing data from utility general rate cases and AMI applications, including:

- The avoided cost of advanced metering infrastructure (AMI) - Historical applications for AMI could be used as an indication of the cost of deploying meters and communications networks.
- The avoided cost of line sensors - Historical smart grid applications for line sensors

- Minimizing the quantity and duration of truck rolls - Using the average rate for a truck roll and an estimated time reduction for outage and power quality restoration
- Minimizing the length of outages or power quality problems - Using the estimated cost of interruption and an estimate time reduction

The next steps are:

SEIA's proposed approach uses data from utility General Rate Cases, AMI and Smart Grid applications to develop a general estimate of the value of situational awareness on utility distribution systems. This information could be used to provide a general assessment or approximation of the cost of providing situational awareness.

Recognizing that DER providers should not afforded value for services that the utilities are already obtaining using previously deployed equipment, forward looking value for situational awareness should be ascertained using the cost of proposals to deploy infrastructure for the purpose of providing situational awareness that are pending before the Commission but not yet approved.

WG Report Item 13:65 Data/Situational Awareness

Joint IOUs' Response to SEIA Proposal

LNBA Working Group

Summary of Response

SEIA argues that many distributed energy resources (DERs) include monitoring equipment and communications-enabled smart inverters, and that third-party DER providers can deliver DER data to utilities so that they can (1) calculate gross load, (2) identify and respond to faults more quickly, and (3) be aware of power quality conditions on the primary distribution system. SEIA also argues that this data would be provided at a greater frequency than what may be available through utility communications infrastructure.

While improved access to DER generation output data will help to improve grid operator situational awareness, it is insufficient for addressing the utilities' situational awareness needs, as described further below.

1. **Gross Load** – To calculate gross load, utilities require both generation output and net load information. DERs provide generation output information, but they do not provide load information. Even with real-time DER generation output information, other infrastructure—which SEIA proposes could be avoided—would still be needed in order to obtain real-time load information. Furthermore, DER generation data could only be obtained from a subset of DERs that have smart inverters and sufficiently reliable communication, and it is unclear whether this incomplete data would be an improvement on methods the IOUs currently have to estimate gross DER generation.
2. **Fault Identification** – The IOUs disagree with SEIA's claim that DERs can improve identification of fault locations for faster restoration because (1) DERs can only provide data that the IOUs already obtain today via advanced metering infrastructure (AMI) to assist with signaling that a fault exists in an area and (2) it is impossible for DER data (or any device at the customer level, including smart meters and AMI) to actually locate the faulted circuit segment. Although DERs may be capable of identifying when a customer is experiencing a service outage (typically internal to a customer's electrical system), the utilities' AMI systems already provide this information today. While this AMI outage information is already used to signal a fault today, it is insufficient for locating faults, especially for outages spanning multiple circuit segments. Line sensors, SCADA data and fault indicators on the primary distribution system provide the

[65] See R.14-08-013, 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 Proceedings, page 13 (Item 13: Explore possible value of situational awareness or intelligence (June 7, 2017) and SEIA response entitled "Item 13: Data/Situational Awareness SEIA Initial Proposal," submitted to the LNBA Working Group.

additional information (e.g. magnitude, direction and distance) needed for more precise fault location calculation, information that DERs and AMI cannot provide. Fault indicators placed directly on the primary distribution line provide the fault direction and more precise fault location necessary for faster fault identification.

3. **Power Quality** – DERs can provide voltage at their respective locations, typically within a customer's electrical system, but not on the primary distribution system. This information could potentially be used as a means to determine secondary distribution system voltage conditions. However, DERs cannot provide voltage information on the primary distribution system since they are not directly connected to the primary system. The utilities' AMI systems can provide voltage at these secondary distribution system locations today. Although the AMI systems generally only provide this information once per day, the reporting frequency can be increased when and where necessary, and the IOUs are exploring expansion of voltage reporting frequency and granularity, where justified.[66]
4. **Reporting Frequency** – Although DERs may be capable of providing customer outage and voltage information more frequently than currently provided by the utilities' AMI systems, this is not necessary. While the utilities would like to receive generation output information in real-time, the utilities would not benefit from DERs providing real-time outage or power quality information.

SEIA proposes that the value of this DER data is equivalent to the avoided cost of (1) additional wireless communications bandwidth for backhauling the data, (2) additional metering of onsite generation, (3) reduced truck rolls, and (4) line sensors. The DER data described in SEIA's proposal would result in no avoided cost to the utilities. As such, SEIA's proposed method of calculating the value of DER data is misguided and should be disregarded.

Situational Awareness

In defining the term "situational awareness," SEIA quotes the Department of Energy's definition of the modern distribution system platform (DSPx), which, in part, states:

The analog-to-digital transformation of the distribution grid requires a much **improved awareness of the current grid configuration, asset information and condition, power flows, and events** to operate the distribution grid reliably, safely, and efficiently. **This may include visibility of all steady-state grid conditions such as criteria violations, equipment failures, customer outages, and cybersecurity**. DER situational awareness is also required to operate a grid with higher DER and optimize DER services to achieve maximum public benefit.[67]

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[66] For example, PG&E demonstrated that current AMI infrastructure can support real-time voltage reads where needed through its volt-VAR optimization (VVO) pilot.

[67] SEIA presentation "Locational Net Benefit Analysis: Situational Awareness," Distribution Resources Planning Working Group, September 19, 2017, page 58

The utilities agree with this definition. In fact, improved grid operator visibility of "power flows and events" are two core capabilities the utilities are seeking to develop through grid modernization.

Gross Load

As the amount of installed DER capacity continues to increase, the principal "situational awareness" challenge faced by utilities is "masked load." Masked load refers to the load on a circuit that, because it is served by customer-sited generation, the grid operator cannot see. Real-time load data for each circuit is available to the operator at the substation. On circuits without DERs, this load data is sufficient for operators to estimate load levels along the circuit. On circuits with DERs, however, load is partially offset by the DER generation, and the operators only see the net load (gross load minus the DER generation).

From the operator's perspective, some load is masked by DER generation such that the operator is unaware that it exists. This limits the grid operators' situational awareness and results in them having to use conservative assumptions when making switching decisions to avoid configuring the system so that, if the DER output is reduced for any reason, the now "un-masked" load causes the circuit to be overloaded. Since grid operators are unaware of the gross load on the circuit—for both the circuit as a whole as well as individual circuit segments—they need to exercise greater caution when transferring load to an adjacent circuit. This is necessary to prevent overloading the adjacent circuit by serving customer load in excess of capacity limits and thereby extending the impact of outages.

Resolving the masked load issue requires that grid operators know the real-time gross load for each discrete circuit segment. Gross load equals net load plus DER generation. To calculate the real-time gross load for each circuit segment, grid operators need both net load and DER generation in real-time.

SEIA proposes that the utilities use DER data in lieu of using utility grid equipment (such as remote fault indicators and smart switches) to calculate gross load. SEIA claims that by providing DER information to utilities' distributed energy resources management systems (DERMS), that utilities can "calculate gross load and more generally understand loading profiles."[68] SEIA also states that "DERs can also provide loading information at each site."[69]

The utilities agree that data on DER generation is essential to helping resolve the masked load challenge. However, this data will not resolve the masked load challenge by itself. Although many DERs have monitoring equipment, this equipment only monitors DER generation output, not load.[70] To monitor load, the DERs would require an additional monitor located at the customer meter. But the DERs simply do not have this instrumentation. Moreover, even if the utilities obtained the DER generation data in

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[68] "Item 13: Data/Situational Awareness SEIA Initial Proposal," page 1.

[69] "Item 13: Data/Situational Awareness SEIA Initial Proposal," page 2.

[70] On page 5 of "Item 13: Data/Situational Awareness SEIA Initial Proposal," SEIA suggests that the utilities may be misinterpreting Rule 21. The utilities are not opposed to using other options that are "less intrusive and/or more cost effective" for obtaining generation output data for larger DERs. However, DERs are currently only capable of providing DER generation information, not site load information.

real-time, they would only be capable of aggregating the DER generation data to derive the gross load of the entire circuit. This DER data alone would not, however, allow utilities to calculate gross load by circuit segment.

Determining gross load by circuit segment requires line sensors to provide real-time data on those specific circuit segments. Circuit segments are sections of a circuit divided by circuit ties, which allow load from one circuit segment to be transferred to an adjacent circuit. When utilities transfer load from individual circuit segments they need to know the magnitude of the gross load they are transferring—otherwise they risk overloading the adjacent circuit. Therefore, although the utilities appreciate the value of obtaining DER generation data, whether from large DERs directly or through DER provider networks, this data needs to be combined with additional telemetry to accurately measure real-time gross load.

Fault Identification

SEIA also suggests that DERs are capable of identifying faults and helping to restore service more quickly. The implication from SEIA again is that this DER capability obviates the need for utility assets that perform the same function. SEIA suggests that using DERs for these functions would "identify faults for faster service restoration"[71] and reduce "truck rolls from better fault location" information, and result in "avoided cost of line sensors."[72] There are a number of issues with SEIA's portrayal of this DER benefit.

1. **Fault Location Identification** – DERs are undoubtedly capable of signaling when there is a power outage (by detecting loss of voltage). However, identifying a customer experiencing a power outage is not equivalent to identifying a fault location. Whereas DERs may be able to help determine the number of customers experiencing an outage due to fault—which the utilities' AMI systems already do today—remote fault indicators installed on the primary distribution system are capable of detecting the specific line segment experiencing the fault. Line sensors need to be located on the primary distribution system[73] in order to help locate where the fault actually occurred on the system. Behind the meter information is unable to provide this same capability since they cannot monitor real-time information on the primary distribution system and provide the location of a fault.

2. **Instrument Location and Density** – Increasing the efficiency of locating a specific fault location involves installing line sensors at key points within each circuit segment such that there is adequate coverage of all load served by the circuit. These sensors are typically installed on primary distribution

[71] "Item 13: Data/Situational Awareness SEIA Initial Proposal," page 1.

[72] SEIA slide deck "Locational Net Benefit Analysis: Situational Awareness," Distribution Resources Planning Working Group, September 19, 2017, page 63.

[73] Primary distribution system refers to equipment that operates above 600V. This is the portion of the distribution system that operates in in the range of thousands of volts and transfers power from the distribution substation to the service transformer. The service transformer then steps down the voltage from the thousands of volts to hundreds of volts (secondary system) to be used by customers. DERs are typically installed at customer locations connected to the secondary which is unable to provide any data on the primary distribution system.

conductors. DERs are unable to provide this service as they do not monitor real-time load flow on primary distribution equipment.

3. **Instant Notification** – Remote fault indicators automatically send a signal to the grid operator notifying them of the faulted circuit segment within seconds of the event. This prompts the grid operator to utilize automated switching, where available, and then dispatch a field worker to investigate. In addition to being unable to identify the circuit segment on which the fault occurred, any latency in communication between the DER provider network and the grid control center means that relying on DER data for outage notification could take longer than the utilities' existing AMI systems and remote fault indicators, increasing customer outage times.

4. **Fault Interruption** – When smart switching devices (such as remote intelligence switches), detect an outage, they can execute switching schemes automatically and in some instances avoid the outage altogether for a subset of customers by using fault interrupting equipment. DERs, however, do not have this added feature.

Power Quality

SEIA states that one of the benefits of utilities' using DER data is that it can "provide nodal level data on power quality conditions."[74] SEIA is referring solely to voltage—not the many other measures associated with power quality, such as total harmonic distortion. DERs can provide voltage data at their respective locations on the secondary distribution system, but not at the primary distribution system (the nodal level). Moreover, the same voltage information provided by behind the meter DERs can be provided today by the utilities' AMI systems. Although the AMI systems generally only provide this information once per day, the reporting frequency can be increased when and where necessary. It is unclear what incremental value would be provided by having this DER information.

Reporting Frequency

Finally, SEIA argues that DERs could "provide data at greater frequency than may be available through utility communications infrastructure."[75] Although DERs may be capable of providing outage and voltage information more frequently than the utilities' AMI systems, this is unnecessary. First, the outage information would be duplicative with the information provided by the utilities' AMI systems. Moreover, this information would be insufficient for identifying a fault location, as discussed above.

Remote fault indicators, on the other hand, provide more precise fault location information. Therefore, any increase in reporting frequency of outage and voltage information would provide no incremental benefit beyond what is providing by existing utility infrastructure, and it would be inferior to the information provided by remote fault indicators.

The utilities welcome opportunities to leverage DER capabilities to improve grid operator situational awareness. DERs can provide information that will support grid flexibility and improve grid operator visibility of power flows. However, while DER data is helpful, it alone cannot resolve the growing

[74] "Item 13: Data/Situational Awareness SEIA Initial Proposal," page 1.

[75] "Item 13: Data/Situational Awareness SEIA Initial Proposal," page 1.

situational awareness challenges the utilities face. This data must be paired with other information obtained directly from the distribution system. Both are essential to meeting the utilities' situational awareness needs for operating the grid safely and reliably.

WG Report Item 14: Benefits of increased reliability (non-capacity related)

SEIA Initial Proposal
LNBA Working Group

Summary of Recommendations

- Some DERs provide substantial reliability benefits beyond providing back-tie capacity, and outside of microgrids, and these values should be captured in the LNBA;
- Utilities use avoided customer minutes of interruption, and their associated costs, to justify the cost effectiveness of investments in grid modernization. Most of these costs come from a small number of commercial and industrial customers, meaning that these customers realize most of the benefits in enhanced reliability. Reliability benefits of utility investments should be treated comparably to benefits from distributed energy resources; and
- There are two ways to calculate the reliability benefits of distributed energy resources outside of capacity ("back-tie") projects:
    - 1) calculating the avoided costs of customer minutes of interruption
    - 2) calculating the avoided costs of non-capacity reliability equipment

Introduction and Background

For the purposes of the DRP Demonstration B projects, the IOUs used the ability of DERs to provide "back-tie" services as the avoided cost value for reliability. Specifically, DERs could reduce load, effectively increasing the amount of load that could be transferred through a tie line during abnormal configurations. For resiliency, the IOU's LNBA demonstration projects considered the value of a micro-grid providing excess reserves for restoring customers and islanded power to customers within the microgrid during outages. Both DER-provided reliability and resiliency service definitions were pulled from the definitions created in the Competitive Solicitation Working Group[76]. This may have been appropriate for the demonstration project but provides a very narrow valuation of distributed energy resources.

Utilities are using measures of customer interruption as a metric for justification of grid modernization investments[77]. Studies have shown that these costs vary widely across and within rate classes, with some customers (such as large C&I customers manufacturing goods) having much higher interruption

[76] Competitive Solicitation Working Group Final Report (August 1st, 2016), p.12-13

[77] http://www.nexant.com/resources/using-customer-reliability-benefits-assess-grid-modernization-priorities

costs than others (such as residential customers)[78]. However, while the benefits of improved reliability are disproportionately realized by a relatively small number of customers, utility investments in Fault Location and Service Restoration, automated switching, and other distribution automation investments are socialized. At the same time, these investments are unlikely to be made in areas with low population density, but likely high risk for outages; this is a situation which could be aptly addressed by DERs either within a microgrid or as stand alone resources.

Particularly in light of expected broad stationary battery storage adoption, and customer investments in other distributed energy resources (e.g., fuel cells) that can island from the grid and provide electricity service during outages, it is reasonable to consider the ability of these resources to offset costs that might otherwise be addressed through grid modernization investments intended to improve reliability.

Discussion

In their presentation to the LNBA working group on October 16th, the IOUs presented on the definition of "non-capacity reliability" projects. SEIA agrees with the IOUs characterization of the different projects:

- Detecting faults on the grid (e.g., circuit breakers, automatic reclosers)
- Locating faults on the grid (e.g., sensing equipment)
- Sectionalizing circuits to minimize the impacts of faults (e.g., switches)
- Fixing standards violations (e.g. reconfigure underground structure or distribution pole)

SEIA agrees that DERs are unable to address standard violations. However, SEIA categorically disagrees that can DERs, in aggregate, cannot provide the same reliability improvements that systematic utility investments in fault location isolation and reconfiguration (FLISR) investments would provide. The intent of adding more switches, identifying faults, and using automation is to reduce the amount of time that customers on a line segment are without service. These investments are justified by the cost to customers (at a system wide level) of the additional length of an outage these customers would suffer. Therefore, it is not appropriate to compare a solar-plus-battery system or a fuel cell against a fault indicator or a switch; these resources would never replace the function of this piece of equipment on a one-for-one basis. Indeed, a battery, for example, is likely to be far more capable, routinely used, and therefore cost effective as it can provide back up capacity to avoid an outage for a customer while also providing other grid services or avoiding customer usage and bills.

It is not a meaningful comparison to consider the function of an automated distribution switch versus a battery or other distributed energy resource. The meaningful question is whether these resources are avoiding customer costs that would otherwise be used to justify utility investments in additional segmentation of lines, more automation, or additional fault indicators. Indeed, many customers already invest in Uninterruptable Power Supply to provide this reliability service for themselves and it is not clear whether utility analyses account for these investments when assuming certain benefits will accrue to these customers with high reliability needs.

[78] https://emp.lbl.gov/sites/default/files/lbnl-6941e.pdf

Methodology

There are two possible methods that could be used to quantify the value of reliability and resiliency. The first is to consider the value of lost load to the utility customers who would otherwise be subject to power outages. The second is to consider utility investments in infrastructure that have been approved or proposed in GRCs for the purpose of improving reliability and resiliency. In general, the Commission's avoided cost methodologies have focused on the utility's cost of serving load, rather than on the value of electricity service to the customers. For that reason, it is probably more appropriate to use the latter method and pull data from GRCs to determine a standard cost to reduce service disruption or restoration of service.

Conclusion and Next Steps

The Commission should determine whether avoided costs of interruption or avoided costs of non-capacity reliability equipment is a more appropriate measure and apply it as part of the Locational Net Benefit Analysis. In the beginning this value could be assessed at a system level. This value could be made location specific by accounting for location specific measures of reliability (SAIDI, SAIFI, MAIFI).

WG Report Item 14: Non-Capacity Related Reliability

Joint IOUs' Initial Proposal
LNBA Working Group

Summary of Recommendations

1. The Joint IOUs recommend that non-capacity related reliability projects related to sensing and isolating faults and correcting standard violations not be considered deferrable by DERs as they do not provide this function.
2. Non-capacity related reliability projects include fault detection related projects and standards violation projects.
    a. Fault related grid services include detection, protection of equipment, isolation, locating of faults, and de-energizing of circuits which are critical to ensure the safety of the public.
        i. Isolating faults and de-energizing circuits require physical changes to the grid which DERs cannot provide.
        ii. DERs can provide information related to which customers are de-energized due to a fault condition. However, grid equipment provides both the detection of faults and de-energizes circuits to ensure the safe operation of the grid. DERs cannot meet the dual purpose nature of circuit breakers and line reclosers.
        iii. Fault indicators provide more locational information identifying the location of the faulted equipment which provide faster customer restoration times. DERs are unable to provide the location of faulted distribution equipment.
    b. Standard violation projects represent physical problems that require configuration changes to grid infrastructure. DERs cannot address the physical nature of these projects.

Introduction and Background

As part of the Distribution Resource Plan (DRP) Track 1's Demonstration Project B (Demo B), non-capacity reliability related projects were divided into two categories, deferrable and non-deferrable. The deferrable reliability projects include back-tie projects and microgrid projects. As the IOUs noted in their Demo B final reports, IOUs defined non-capacity related, non-deferrable reliability projects as (1) detecting, locating, and sectionalizing faults and (2) fixing standards violations.

Discussion

Fault Related Projects

To detect, locate, and minimize the impacts of faults on the grid, there are a number of traditional infrastructure types such as circuit breakers, automatic reclosers, switches, and fault indicators located on the primary distribution lines. These grid devices provide certain unique services necessary to address faults.

Similar to a circuit breaker for the home, grid circuit breakers provide the ability to detect a fault such as a short circuit and de-energize the circuit (i.e., turn off). Automatic reclosers provide all the same benefits of a circuit breaker with the additional benefit of being located along the distribution line which helps limit the number of customers that experience an outage condition. Breakers and reclosers also have the ability to automatically energize the circuit (i.e., turn on). This action minimizes the outage if the fault is transient. If the fault still exists on the circuit, both a breaker and recloser will detect the fault again and de-energize the circuit. Both circuit breakers and automatic reclosers provide a dual purpose of detecting faults and de-energizing equipment for public safety. Decoupling these two grid services would not be prudent since these two services are closely linked to each other. Since DERs do not provide the ability to de-energize a circuit, DERs cannot replace or defer the need for circuit breakers and reclosers on the grid.

Continuing the home analogy, imagine that a circuit in the home provides power to both a TV and an overhead light. The overhead light is also connected to a switch. If the overhead light had a short causing the circuit breaker to trip, the overhead light could be isolated by turning off the switch. This would allow the circuit breaker to be turned back on and power the TV. Similar to this home example, a switch on a circuit provides the ability to isolate a portion of the circuit. During a fault, this allows only a subset of customers connected to the circuit to encounter an outage. Since DERs cannot provide the ability to isolate and de-energize a portion of a circuit and perform the same function as a switch, DERs cannot replace or defer the need for switches on the grid. In addition, switches also allow the transfer of customers from one circuit to a neighboring circuit. This will further reduce the amount of customers impacted by a fault condition that would otherwise impact a large majority of customers on the circuit experiencing the fault. DERs are unable to transfer customers between neighboring circuits and therefore cannot replace the need for switches that provide this operational flexibility.

Using the same example above of a home circuit powering both a TV and overhead light on a switch, if a fault occurred somewhere on the segment that provided power to the overhead light, the inability for the light to turn on indicates that there is a fault. The fault is somewhere on the circuit segment that is part of the overhead light, but further locational information is not provided. On the grid, similar to the overhead light, the DER could potentially provide information that there is a fault, but not where it would be on the circuit segment. On the other hand, fault indicators provide locational information to narrow the area of where the issue resides. This allows for quicker response to fix faults on the system. Since DERs cannot provide this locational information, DERs cannot defer or replace fault indicators.

Standards Violation Projects

Standards violation projects address physical equipment such as equipment in underground vaults and overhead poles. IOUs address standards violations to ensure both reliability and public safety. For example, an overhead pole could be overloaded with equipment stressing the pole. To fix this issue, the IOU would reduce the equipment on that pole. Since the solutions for standards violations are often physical in nature, DERs would not be able to defer or avoid these types of projects.

Item 14: Non-Capacity Related Reliability

Joint IOUs' Response to SEIA Proposal
LNBA Working Group

General Response

SEIA's proposal implies that back-up generation installed behind a customer meter could avoid the need for grid modernization investments. Specifically, investments that detect electrical faults on the grid, and enable IOUs to isolate and de-energize the faulted circuit section while maintaining service to as many customers as possible by reconfiguring the system to energize intact sections through alternate pathways would still be necessary. These investments include equipment required to maintain electric grid safety and reliability through increased situational awareness and operational flexibility.

Customers choosing to invest in sufficient backup generation could potentially disconnect their facilities from the grid during an outage and serve their local loads at those specific locations. However, this would not eliminate the need for switches, fault indicators, and protection equipment that ensure the safe operation of the electric system, and provide situational awareness and operational flexibility. Grid modernization equipment provides the ability to transfer entire sections of circuits (i.e., several hundred customers) between neighboring circuits in the event of an outage, allowing these customers to remain energized. These reliability benefits are provided irrespective of the number of customers who purchase their own backup generation.

To avoid these grid modernization investments, each customer would need to purchase their own backup generation. Even then, certain grid modernization investments would still be required for situational awareness purposes to identify faults and to restore service. This would be necessary to allow customers to come off their backup generation—unless it is sized to support customers' ability to separate from the electric grid indefinitely. However, this would require substantially oversizing the backup generation, which is not possible for many customers, particularly those in multi-family dwellings. Indeed, these customers would likely find it difficult to site any backup generation. This approach would therefore penalize customers unable to install backup generation, either due to physical constraints or financial limitations.

SEIA's proposal also suggests that DERs can provide additional reliability benefits, including detecting faults on the grid, locating faults on the grid, and sectionalizing circuits to minimize the impacts of faults.[79] As stated in the joint IOUs response to the SEIA and Tesla proposal related to situational awareness,[80] DER capabilities are insufficient for providing these essential grid services.

The IOUs' approaches to grid modernization would be more cost effective than installing back-up generation at every location, and preserves individual customers' ability to choose whether or not to invest in backup generation.

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[79] Item 14: Benefits of increased reliability (non-capacity related), SEIA Initial Proposal, page 3

[80] Item 13: Data/Situational Awareness Joint IOUs' Response to SEIA Proposal LNBA Working Group

Back-Up Generation vs. Operational Flexibility

SEIA's proposal that back-up generation can replace equipment that enables operational flexibility must consider cost effectiveness and customer choice. The IOUs want to enable customers to choose how they receive electrical power such as back-up generation at their location. SEIA states in their proposal that C&I customers may have higher interruption costs compared to residential customers. This is a perfect example of a subset of customers that are more willing to pay for these back-up services while others may not believe it's worth it.

If a switch was avoided due to a back-up generation option, in order to provide the same service, all customers that could have been transferred due to that switch would require back up generation at their specific locations. For example, one switch installation can typically enable the transfer of a large number, say 200 customers, to a neighboring circuit in the event of an outage. In order to provide the same service as that switch, all 200 customers would require back-up generation. In addition, a small portion of those customers could be C&I while the vast majority is residential. Most likely there will be differing customer desires and abilities to install back-up generation at their location both related to equipment and cost especially when comparing the cost of a switch versus 200 back-up generation installations of varying sizes.

Reliability Investment Locations

SEIA states that "However, while the benefits of improved reliability are disproportionately realized by a relatively small number of customers, utility investments in Fault Location and Service Restoration, automated switching, and other distribution automation investments are socialized. At the same time, these investments are unlikely to be made in areas with low population density, but likely high risk for outages; this is a situation which could be aptly addressed by DERs either within a microgrid or as stand-alone resources."[81]

SEIA makes the assumption that, since a certain subset of customers place higher value on reliability, those customers are the primary beneficiary from socialized investments in reliability.[82] This is precisely the skewed result that would occur if faulty assumptions of DERs' ability to avoid any reliability investment give rise to some incremental incentive that is paid by IOU customers generally and given to individual customers for investing in their own reliability.

In reality, IOUs gather detailed reliability data to display areas that would benefit from these types of investments. SEIA also claims, without basis, that utilities are unlikely to invest in areas at high risk for outages, but with low population density. This is not accurate. If an area displays the need for reliability investments, detailed engineering analysis is performed in order to understand how reliability can be

[81] Item 14: Benefits of Increased reliability (non-capacity related) SEIA Initial Proposal p. 2

[82] "…some customers (such as large C&I customers manufacturing goods) having much higher interruption costs… while the benefits of improved reliability are disproportionately realized by a relatively small number of customers, utility investments in [reliability] are socialized." Item 14: Benefits of increased reliability (non-capacity related), SEIA Initial Proposal, page 1

increased, including consideration of a microgrid solution. In addition, the outage risk of any region depends on many factors, including population density, weather, equipment location, equipment age, animal population, and amount of sectionalizing equipment/fault indicators all play a part in how high risk an area is to experience outages.