Locational Net Benefit Analysis Working Group - Group II-III Interim Status Report
Prepared for the LNBA Working Group by More Than Smart on October 31, 2017

Background:

A June 7, 2017 Assigned Commissioner Ruling (ACR) set a scope and schedule[1] for continued long-term refinement (LTR) discussions on both Integration Capacity Analysis (ICA) and Locational Net Benefit Analysis (LNBA). This ACR includes pre-Working Group (WG) deliverables, status reporting, and final reporting milestones for continued long-term refinement discussions. This ACR groups the identified long-term refinement topics into three groups, which front-loads work on topics of relatively high complexity and/or importance to the further development of ICA. The two Group II topics are as follows:

Group II Topic	June 7 ACR Item #
1. Incorporate a (forecasting) uncertainty metric in LNBA tool for planned deferrable projects (requires coordination with development of deferral screening criteria under development in DRP Track 3 Sub-track 3)	WG Report - 7
2. Only use base DER growth scenario, not high growth scenario (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)	WG Report - 11

The eight Group III topics are as follows:

Group III Topic	June 7 ACR Item #
1. Methods for evaluating location-specific benefits over a long term horizon that matches with the offer duration of the DER project	ACR - A
2. Develop a methodology to quantify the likelihood of an unplanned grid need (Deferrable project) emerging in a given location	WG Report - 8
3. Value locational value of DERs beyond 10 years	WG Report - 9
4. Explore asset life extension/reduction value provided by DERs	WG Report - 12
5. Explore possible value of situational awareness or intelligence (Value of data-as-service for situational intelligence is likely hard to quantify on	WG Report - 13

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

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)	
6. Include benefits of increased reliability (non-capacity related) provided by DERs	WG Report - 14
7. LNBA should value benefits of DERs reducing the frequency/scope of maintenance projects	WG Report - 16
8. LNBA should include benefits of DER penetration allowing for downsized replacement equipment due to be installed in the case of equipment failure or routine replacement of aging assets	WG Report - 17

The Working Group has had two meetings on Group II and III topics. The meeting notes, webinar recordings, participant lists, and slides from those meetings are included as links in Appendix A of this status report.

The Working Group established a consensus method for discussing topics, developing written proposals, and receiving edits or comments on those proposals. These are detailed in the proposal document, found here.[2] This interim status report identifies which parties have submitted proposals, which parties have submitted comments, and summarize discussion and next-steps to date. These proposals can be found in Appendix B and reflect the main work products of this WG to date, incorporate feedback and comments made during the in-person monthly meeting, and will assist the WG in developing the final WG report due January 2018.

[2] http://drpwg.org/wp-content/uploads/2016/07/High-Level-ICA-LNBA-LT-Refinements-WG-Project-Plan-v.6.29.docx

Group II Topic 1 (WG Report - 7). Incorporate a (forecasting) uncertainty metric in LNBA tool for planned deferrable projects (requires coordination with development of deferral screening criteria under development in DRP Track 3 Sub-track 3)

Overview: 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.

Initial proposals: At the September meeting, the Joint IOUs proposed that 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 are to be evaluated in LNBA (pursuant to a final DRP Track 3 Sub-track 3 decision). The Joint IOUs also clarified that "uncertainty" in this context specifically refers to forecasting (projects closer to the year in which a need is forecasted to occur is more "certain" and would be a higher priority project). The uncertainty metric is qualitative and should 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. The 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. Finally, the 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.

Edits and comments: No written comments were submitted.

Timeline and next steps: The LNBA will include all potentially deferrable projects that pass the deferral technical screens identified within the IDER OIR. The IOUs will display the qualitative certainty metric (low, medium, high) as an additional LNBA map layer. 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. Finally, 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 ED workshops pertaining to the third use case, as part of CPUC's Track 1 Decision on ICA and LNBA.

Group II Topic 2 (WG Report - 11). Only use base DER growth scenario, not high growth scenario

Overview: The Joint IOUs were directed in Demo B to use both a trajectory DER growth scenario (consistent with the forecast used by IOUs within the distribution planning process) and a "very high" DER growth scenario which represents the full implementation of a number of ambitious policy objectives, resulting in dramatic acceleration of growth for many DER technologies. 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 it "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." Some WG members identified the need for this topic in order to identify needs expected to occur under different DER scenarios.

Initial proposals: At the September meeting, the Joint IOUs proposed that the LNBA should remain consistent with distribution planning process, stating that LNBA results are meaningless if divorced from IOU distribution planning. Currently, IOU distribution planning only uses a single forecast. While the Track 3 ACR on growth scenarios explicitly includes the use of multiple DER growth scenarios within the Grid Needs Assessment, discussion on whether or how this might be incorporated within LNBA via long-term refinement should only follow a Track 3 Decision.

Edits and comments: No comments were submitted.

Timeline and next steps: The Joint IOUs will plan to use the trajectory DER growth scenario. Additional long-term refinement discussion may occur only after a Track 3 decision addresses the use of multiple growth scenarios.

Group III Topic 1 (ACR - A). Methods for evaluating location-specific benefits over a long term horizon that matches with the offer duration of the DER project; Topic 2 (WG Report - 8). Develop a methodology to quantify the likelihood of an unplanned grid need (Deferrable project) emerging in a given location; and Topic 3 (WG Report - 9). Value locational value of DERs beyond 10 years

Overview: The June 7 ACR identifies topics A, 8, and 9 as the same, as valuing unplanned grid needs encompasses long-term (>10-year) grid needs. However, such values are identified by the ACR as speculative and likely difficult to quantify for practical use in the LNBA. The status report thereby groups these three items together.

Initial proposals: The IOUs presented slides for discussion at the October meeting, but did not formulate a written proposal. The IOUs parsed discussion into 1) unplanned needs within the distribution planning horizon (10 years), and 2) grid needs identified beyond 10 years. The details of this presentation may be found in the presentation slide deck.

With regards to unplanned grid needs within the planning horizon, the IOUs define the majority of unplanned needs as large spot load additions that could arise in a short time period that could force additional voltage or capacity projects to accommodate new load (e.g., high rise buildings); additionally many of these projects are grid-edge projects which will require new utility infrastructure to connect to the grid. Considering the size of these loads, it would be difficult to stimulate DER market activity quick enough to meet load needs within a reasonable amount of time (e.g., less than two years) - the IOUs sense that DERs could only avoid this cost through a utility-driven solicitation, and will draw on results from Demo C to further understand DER implementation timelines. The IOUs are willing to track the value and number of unplanned capacity investments going forward to better understand the dollar value associated with unplanned grid investments.

With regards to grid needs beyond 10 years, the IOUs state that the majority of system-level benefits provided by DERs are already accounted for beyond 10 years, and that only T&D values are not included. This is because forecasting grid needs beyond 10 years is highly speculative, though the actual T&D value will still exist after 10 years as long as a T&D project is still needed without the DER providing capacity service at that time. The IOUs believe this T&D value should be assessed at the time of need, if the value still exists,, to incentivize the resource to stay online.

Edits and comments: CALSEIA provided comments responding to the IOUs' initial thoughts on valuing unplanned grid needs. With regards to unplanned projects within the planning horizon, CALSEIA clarifies that voltage-related projects may not follow the same line of reasoning the IOUs presume for capacity projects (i.e., due to large spot needs), and recommends that the IOUs provide more detail on how far in advance they typically identified specify voltage-related distribution upgrades. With regards to capacity projects, CALSEIA states that the IOU perspective on DERs providing value in these situations may be accurate from a deferral solicitations perspective, but does not accurately reflect the value of DERS in a locational benefits perspective. To accurately account for the benefits of DER, the LNBA methodology should reflect the value of DERs in 1) delaying upgrades that have been generally identified, but not specifically planned; 2) delaying upgrades beyond the 10-year planning horizon; 3) providing flexibility for upgrades under development; and 4) deferring the need for voltage-related upgrades. CALSEIA proposes that this value could be calculated by the IOUs by first determining how many construction projects were identified in the planning process for less than 10 years (to give an indication of the number of projects that were not candidates for deferral solicitations due to timing), then determining how many projects have remained in the planning process for longer than ten years (i.e., identified through multiple planning documents representing a period over ten years, but not implemented), to give an indication of what portion of projects were delayed due to DER adoption and other changes in forecasted growth. During the October meeting, the IOUs indicated that this analysis may be too difficult to do systematically. CALSEIA tates that the best alternative means to calculate these benefits would then to include distribution marginal costs in the value of incremental DER adoption.

Timeline and next steps: The WG will follow-up with the unplanned projects discussion at the November in-person meeting. This is likely a non-consensus topic. Other WG members are asked to comment on the Joint IOUS' and CALSEIA's proposals in advance of the November meeting.

Group III Topic 4 (WG Report - 12). Explore asset life extension/reduction value provided by DERs

Overview: The June 2017 ACR includes Item 12: "Explore asset life extension/reduction value provided by DERs" as a Group 3 topic. 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.

Initial proposals: Tesla, on behalf of SEIA, and the Joint IOUs presented separate proposals at the October meeting. During the meeting, the IOUs discussed that distribution assets are primarily removed from service due to 1) failure (e.g., environmental factors, wear and tear, thermal degradation, manufacturing defects, etc.); 2) obsolescence; and 3) redeployment. DERs can only impact asset life for a subset of distribution assets (wear and tear, and thermal degradation). Characterizing how DERs interact with the physical mechanisms of wear and tear and thermal degradation is highly complex. 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). 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. Based on the available material, the Joint IOUs note that current research suggests that DERs' impacts on asset life – as distinguished from O&M and distribution capacity deferrals – are minor and ambiguous and thus should not be included.

Tesla commented that there are multiple areas of consensus between its proposal and the IOUs' proposal. Tesla additionally commented that a 1993 study[3] may provide further insight on how this value may be calculated (using IEEE C57.12.00-2000 standard per unit life calculation methodology, which includes value of both deferred capacity and energy efficiencies created by operating equipment more efficiently within ratings).

Edits and comments: ORA supports the Joint IOU proposal at this time. ORA will consider additional evidence on this topic provided by DER vendors and research findings as that information becomes available.

Timeline and next steps: 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 at a later date within the WG.

[3] "The Value of Grid-Support Photovoltaics to Substation Transformers", Hoff and Shugar, Pacific Energy Group and Pacific Gas & Electric (PG&E), 1993.

Group III Topic 5 (WG Report - 13). Explore possible value of situational awareness or intelligence

Overview: 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."

Initial proposals: SEIA and Tesla, and the Joint IOUs, presented separate proposals on situational awareness. The IOUs proposed to define the situational awareness DER benefit as the provision to the utility distribution company of grid info which is collected using DERS, and which meets the following requirements: 1) the info meets a specified grid need for which the IOUs are planning an investment, 2) the info meets the data requirements as specified by the IOU, and 3) the info is not already required to be provided by the DER. In the absence of a defined grid need, there is no avoided cost value. The value is equal to the avoided RRQ of deferring otherwise-needed capital investment calculated using the RECC method. The IOUs' written proposal identify further key questions to developing this value. These reflect questions surrounding grid data collection costs, interconnection requirements for smart-inverter based DERs, and solicitation of services versus LNBA value.

SEIA and Tesla state that DER providers can provide data to the IOUs 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 and Tesla propose to calculate the value of situational awareness as the incremental cost of more frequent, customer-level data and provision of power quality information. The value of this service can be calculated using data from GRCs and AMI applications, 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.

Edits and comments: SEIA provided a response to the IOUs' key questions on avoided and hidden costs of providing grid data, and minimum interconnection requirements for smart inverter-based DERs.

The Joint IOUs submitted a response to the SEIA proposal, stating that DER generation output data insufficiently addresses the IOUs' situational awareness needs and therefore does not provide an avoided cost to the utilities.

ORA has no additional comments on this issue at this time and suggests that additional information may be needed to verify the factual claims in the SEIA and IOU proposals and the IOU response to the SEIA proposal. For non-consensus LNBA items, ORA suggests that, these factual claims would be best explored via a discovery process followed by written testimony, rebuttal testimony, and hearings.

Timeline and next steps: This is a non-consensus item and will be identified as such in the Final Report. Other LNBA stakeholders are welcome to provide comment.

Group III Topic 6 (WG Report - 14). Include benefits of increased reliability (non-capacity related) provided by DERs

Overview: This item was marked in the Final Demo B Working Group Report as a non-consensus item. This benefit refers to increased value due to DERs providing increased reliability services via outage frequency reduction (duration, magnitude, etc.). For Demo B, non-capacity reliability related projects were divided into deferrable (back-tie, microgrid) and non-deferrable projects.

Initial proposals: Tesla, on behalf of SEIA, and the Joint IOUs both presented at the October meeting. The Joint IOUs recommend that non-capacity related reliability projects should be defined to include fault detection related projects and standards violation projects, but projects related to sensing and isolating faults and correcting standard violations not be considered deferrable by DERs as they do not provide this function. Regarding fault-related projects, DERs cannot replace or defer the need for circuit breakers and reclosers, cannot transfer customers between neighboring circuits (providing operational flexibility), and cannot defer/replace fault indicators or identify their location on the circuit.

SEIA proposed that some DERs provide substantial reliability benefits beyond providing back-tie capacity, and outside of microgrids, particularly for a small number of commercial and industrial customers (who place a higher value on avoided interruption costs and realize the majority of the enhanced reliability benefits from utility investments). SEIA proposes this can be calculated through two potential methods: 1) consider the value of lost load to the utility customers who would otherwise be subject to power outages, or 2) consider utility investments in infrastructure that have been approved/proposed in GRCs for the purpose of improving reliability and resiliency. SEIA believes the latter is more appropriate, using data from GRCs to determine a standard cost to reduce service disruption or restoration of service, and could be made more location specific using location-specific SAIDI, SAIFI, and MAIFI data.

Edits and comments: SEIA disagrees with the Joint IOUs direct comparison of DERs such as solar+storage or fuel cells against a fault indicator or switch, given that DERs would not be considered as a one-for-one replacement; rather, using a DER system may result in avoiding customer costs that would otherwise be used to justify utility investments to provide reliability services. 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. ORA submitted short comments supporting the SEIA proposal.

The IOUs disagree with SEIA's statement that DERs providing back-up generation would eliminate grid modernization investments like switches and fault indicators, and state that SEIA's proposal reduces cost effectiveness and customer choice, lowers utilities' operational flexibility ability. The IOUs also disagree with SEIA's assumption on which subset of customers receive skewed reliability benefits.

Timeline and next steps: This is a non-consensus item. Additional stakeholders are invited to comment on both the Joint IOUs' and SEIA's proposals.

Group III Topic 7 (WG Report - 16). LNBA should value benefits of DERs reducing the frequency/scope of maintenance projects

Overview: The ACR includes benefits of DERs reducing the frequency/scope of maintenance projects as that the "value proposition is speculative and potentially low." In late September, LNBA Working Group members were asked to prioritize the remaining LNBA topics for discussion, including Group III topics. This was identified by a majority of WG members as a low priority topic.

Initial proposals: This was identified as a low priority topic, for discussion at the October meeting if time permitted. The WG did not discuss this item in October, so there was no developed written proposal. The Joint IOUs did prepare slides explaining their thoughts, which are included in the presentation deck *(see Appendix)*. To sum, operations and maintenance includes a) equipment testing to ensure proper functionality (e.g. fire systems, testing operations of switches, breakers); b) scheduled equipment and structure inspections (e.g. substation transformer dissolved gas analysis, distribution switch oil/gas levels, fix signage/markings); and c) vegetation management. The IOUs state that that there is currently no reliable evidence that DERs can defer the aforementioned types of operations and maintenance work.

Edits and comments: There have been no comments on this item to date.

Timeline and next steps: Interested LNBA Working Group members are invited to submit comment on the IOU proposal or develop their own before the November WG meeting.

Group III Topic 8 (WG Report - 17). LNBA should include benefits of DER penetration allowing for downsized replacement equipment due to be installed in the case of equipment failure or routine replacement or aging assets

Overview: The LNBA Working Group Final Report stated that the value of DERs in downsizing replacement equipment, in the case of equipment failure, routine replacement, or aging assets is a non-consensus item. The June 7 ACR states that the "value proposition is speculative and potentially low." In late September, LNBA Working Group members were asked to prioritize the remaining LNBA topics for discussion, including Group III topics. This was identified by a majority of WG members as a low priority topic.

Initial proposals: This was identified as a low priority topic, for discussion at the October meeting if time permitted. The WG did not discuss this item in October, so there was no developed written proposal. The Joint IOUs did prepare slides explaining their thoughts, which are included in the presentation deck. To sum the prepared IOU slides, the Joint IOUs suggest that downsizing decreases resiliency of the grid, is contrary to the future plug and play electric grid vision (e.g. it reduces capacity to serve future load and generation growth, it potentially results in installation of larger equipment at a later date, resulting in higher costs to customers, and it reduces ability to transfer load and/or generation between circuits due to limited capacity from downsized equipment.)

Edits and comments: There have been no comments on this item to date.

Timeline and next steps: Interested LNBA Working Group members are invited to submit comment on the IOU proposal or develop their own before the November WG meeting.

Appendix A: LNBA Summary of Meetings

Meeting date	Meeting documents
September 19	Working Group meeting on Group II topics Meeting materials: • meeting notes forthcoming • webinar recording • slide deck • participant list
October 16	Working Group meeting on Group III topics Meeting materials: • meeting notes forthcoming • presentation slides • webinar recording • participant list

Appendix B: LNBA Written Proposals and Submitted Comments

Topic	June 7 ACR Item	Initial written proposals	Comments
II.1. Incorporate a (forecasting) uncertainty metric in LNBA tool for planned deferrable projects (requires coordination with development of deferral screening criteria under development in DRP Track 3 Sub-track 3)	WG Report - 7	Joint IOUs	
II.2. Only use base DER growth scenario, not high growth scenario (may entail substantive discussion, but likely will not entail incremental methodology development; requires coordination with DRER growth scenarios under development in DRP Track 3 Sub-track 1)	WG Report - 11	Joint IOUs	
III.1. Methods for evaluating location-specific benefits over a long term	ACR - A		CALSEIA

horizon that matches with the offer duration of the DER project			The June 7 ACR identifies topics A, 8, and 9 as the same, as valuing unplanned grid needs encompasses long-term (>10-year) grid needs.
III.2. Develop a methodology to quantify the likelihood of an unplanned grid need (Deferrable project) emerging in a given location	WG Report - 8		
III.3. Value locational value of DERs beyond 10 years	WG Report - 9		
III.4. Explore asset life extension/reduction value provided by DERs	WG Report - 12	Joint IOUs	
III.5. Explore possible value of situational awareness or intelligence (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)	WG Report - 13	Joint IOUs SEIA and Tesla	Joint IOUs
III.6. Include benefits of increased reliability (non-capacity related) provided by DERs	WG Report - 14	SEIA Joint IOUs	Joint IOUs
III.7. LNBA should value benefits of DERs reducing the frequency/scope of maintenance projects	WG Report - 16		
III.8. LNBA should include benefits of DER penetration allowing for downsized replacement equipment due to be installed in the case of equipment failure or routine replacement or aging assets	WG Report - 17		

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.[4] The Assigned Commissioners Ruling on the Track 1 long term refinements identified this topic as a

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

second tier item that is to be discussed after higher priority tier 1 topics.[5] 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.

[5] "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.[6] 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.[7] The Decision then illustrates the need for these types of analysis to enable DERAC to accurately inform DER tariffs and programs.[8] 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.[9] 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
- 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

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[6] 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
[7] IBID. p. 48
[8] IBID, p.49
[9] IBID, p. 60

- 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

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

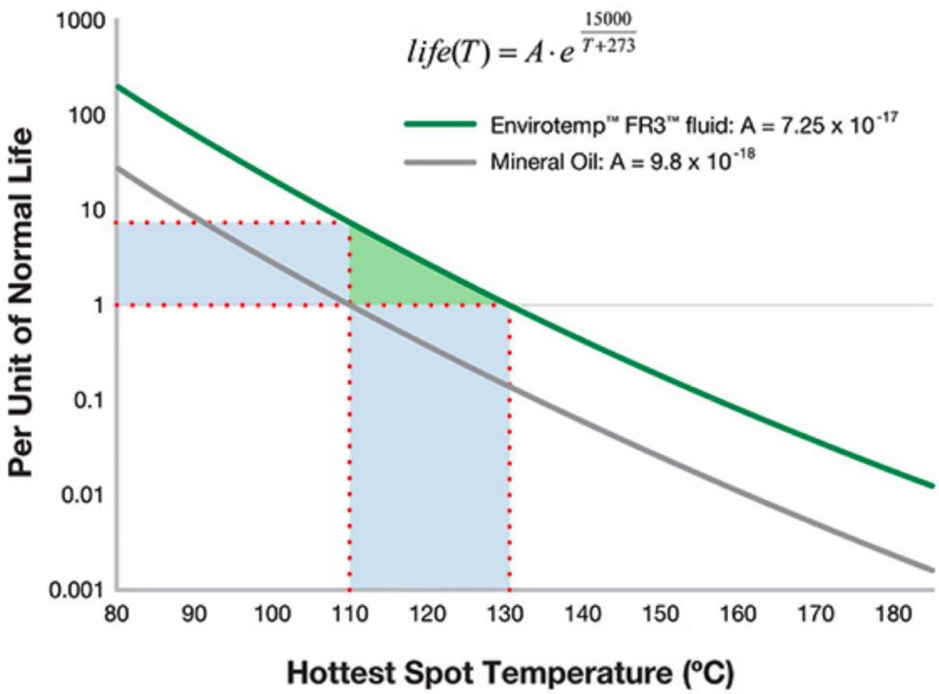
    a. Old design no longer considered safe or functional for current needs (e.g., live front equipment no longer considered safe)
3. Redeployment
    a. Transformers that are not at end-of-life that are replaced as part of a capacity upgrade are usually kept in stock and redeployed. (Note this is not a 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[10] 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[11] 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.

[10] Available here: http://calsolarresearch.ca.gov/images/stories/documents/Sol3_funded_proj_docs/UCSD/CSIRDD-Sol3_UCSD_TapOpsReduction_20151120.pdf
[11] 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.[12]

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.

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

Other recent work by EPRI[13], 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.[14] Distribution deferrals target such planned investments to upgrade distribution capacity. Earlier work in the 1990s[15] tended to describe

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

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

[15] 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.[16] 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.

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.

[16] 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.

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[17] 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.

[17] 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[18] 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?

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

    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, 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?

    - Utility concern: 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:[19] 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 additional information (e.g. magnitude, direction and distance) needed for more precise fault

[19] 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.

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.[20]
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.[21]

[20] For example, PG&E demonstrated that current AMI infrastructure can support real-time voltage reads where needed through its volt-VAR optimization (VVO) pilot.
[21] 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."[22] SEIA also states that "DERs can also provide loading information at each site."[23]

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.[24] To monitor load, the DERs would require an additional monitor located at the customer meter. But the DERs simply

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

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

[24] 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.

do not have this instrumentation. Moreover, even if the utilities obtained the DER generation data in 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"[25] and reduce "truck rolls from better fault location" information, and result in "avoided cost of line sensors."[26] 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[27] 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

[25] "Item 13: Data/Situational Awareness SEIA Initial Proposal," page 1.
[26] SEIA slide deck "Locational Net Benefit Analysis: Situational Awareness," Distribution Resources Planning Working Group, September 19, 2017, page 63.
[27] 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.

coverage of all load served by the circuit. These sensors are typically installed on primary distribution 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."[28] 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."[29] 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.

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

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 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[30]. 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[31]. 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 costs than others (such as residential customers)[32]. However, while the benefits of improved reliability are disproportionately realized by a relatively small number of customers, utility investments in Fault

[30] Competitive Solicitation Working Group Final Report (August 1st, 2016), p.12-13
[31] http://www.nexant.com/resources/using-customer-reliability-benefits-assess-grid-modernization-priorities
[32] https://emp.lbl.gov/sites/default/files/lbnl-6941e.pdf

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.

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.[33] As stated in the joint IOUs response to the SEIA and Tesla proposal related to situational awareness,[34] DER capabilities are insufficient for providing these essential grid services.

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

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

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.

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."[35]

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.[36] This is precisely the skewed result that would occur if faulty assumptions of DERs' ability to avoid any reliability

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

[36] "…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

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 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.