WESTERN INTERSTATE ENERGY BOARD

Distributed Energy Resources:

Technological and Policy Considerations of Hosting Capacity and Locational Value

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Introduction

Distributed energy resources (DERs) include several generation technologies (e.g., rooftop solar photovoltaic (PV) generation, combined heat and power), load management (e.g., demand response, energy efficiency), and various forms of storage (e.g., hybrid solar PV generation/storage systems, electric vehicles). Due to its current popularity, solar PV generation will frequently be used as an example in this paper. DERs provide several benefits, but also pose several challenges, to the electric power system. Benefits and costs of DERs can be grouped into three principal categories: infrastructure-related, energy-related, and environment-related (see Table 1 in Appendix A). Importantly, many benefits of DERs are not uniform, but instead vary according to time and location.[1] The benefit of avoided pollutant emissions illustrates the influence of time. If, as an example, solar PV displaces fossil fuel-fired generation as can occur during daytime hours, significant criteria pollutant (e.g., nitrogen dioxide) and greenhouse gas (GHG) emissions can be avoided. The locational influence can lead to avoidance of infrastructure costs because lesser investments in centralized generation, transmission and/or distribution may be needed with DERs in certain geographic locations.

This policy paper will examine the influence of DER location within a distribution system on benefits. Furthermore, it will frequently point to avoided infrastructure costs as examples of DER benefits. Two recent examples, in New York and California, illustrate the magnitude of costs that can be avoided. First, the Brooklyn-Queens area of New York City is served by the investor-owned utility (IOU) Consolidated Edison (ConEd), which determined in 2014 that the area's electric power demand would exceed infrastructure capabilities in the near future. Historically, the approach to a projection of increased demand would be transmission upgrades, installation of a new substation, and a new secondary network distribution system that would cost approximately $1.2 billion. Alternatives were considered, and the alternative that prevailed, the Brooklyn-Queens Demand Management project, includes multiple DER measures costing ratepayers $200 million.[2] Second, in the IOU Pacific Gas & Electric (PG&E)'s Northern-Central California service territory, distributed solar PV generation and energy efficiency measures recently saved ratepayers nearly $200 million in displaced transmission and distribution infrastructure projects.[3] As Table 2 in Appendix A shows, ConEd and PG&E are IOUs with different characteristics, yet both were able to avoid significant infrastructure costs by

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[1] Kristina Mohlin, *Benefits of Clean, Distributed Energy: Why Time, Location and Compensation Matter*, 2016, http://www.renewableenergyworld.com/articles/2016/05/benefits-of-clean-distributed-energy-why-time-location-and-compensation-matter.html

[2] Jan Ellen Spiegel, *Another $1.2 Billion Substation? No Thanks, Says Utility, We'll Find a Better Way*, 2016, http://insideclimatenews.org/news/04042016/coned-brooklyn-queens-energy-demand-management-project-solar-fuel-cells-climate-change

[3] Julia Pyper, *Californians Just Saved $192 Million Thanks to Efficiency and Rooftop Solar*, 2016, https://www.greentechmedia.com/articles/read/Californians-Just-Saved-192-Million-Thanks-to-Efficiency-and-Rooftop-Solar

leveraging DERs. Given the recent prediction that worldwide DER nameplate capacity will nearly double between 2014 and 2023, potential savings are very large.[4]

This policy paper is the second in a two-part series. The first paper, entitled Distributed Energy Resource Interconnection Timelines and Advanced Inverter Deployment: Their Improvement in the Western Interconnection, was posted earlier this year (see Footnote 10). This second paper draws upon the first paper, particularly its emphasis on deployment of advanced inverters, but extends its examination of Western U.S. policies influencing DER deployment to hosting capacity and locational value of DERs. These two topics are highly related because hosting capacity, a measure of a distribution feeder's capacity to accommodate DERs, is a key determinant of locational value of a given DER. Regulatory activities in the states of California and New York related to hosting capacity and locational value are then covered. Both states are now requiring IOUs to factor hosting capacity and locational value into distribution system planning. California is exploring IOU procurement of DERs to defer or even avoid distribution system investment within a traditional cost-of-service regulatory model, whereas New York is encouraging DER procurement within a new regulatory model. Finally, policy options for Western states are provided. These options will be of value to states already deploying DERs and to those considering DER deployment.

DER Hosting Capacity and Interconnection Screening

A DER must be interconnected with a distribution system in order to make its power output available to the electric grid. In approving interconnection of a DER, a utility must ensure that the DER does not negatively impact electric power quality or reliability. The most common example of negative impacts on power quality is an over-voltage deviation; examples of negative impacts on reliability include unintentional islanding and violations of thermal and protection limits.[5] Hosting capacity refers to the DER nameplate capacity that can be interconnected with a portion of a distribution system without the upgrading of system infrastructure to avoid violation of voltage, thermal, and/or protection limits. Figure 1 below illustrates the concepts of hosting capacity and distribution system infrastructure upgrading.

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[4] Navigant Research, *Global Distributed Generation Deployment Forecast: Solar PV, Small Wind, Fuel Cell, Natural Gas Generator Set, and Diesel Generator Set Capacity and Revenue by Country and Technology, 2014-2023,* 2016, https://www.navigantresearch.com/research/global-distributed-generation-deployment-forecast. Worldwide DER nameplate capacity is predicted to increase from 87,300 to 165,500 megawatts over 9 years.

[5] As an example, the service voltage range in North America is 114-126 volts. Thus, an over-voltage deviation is one greater than 126 volts.

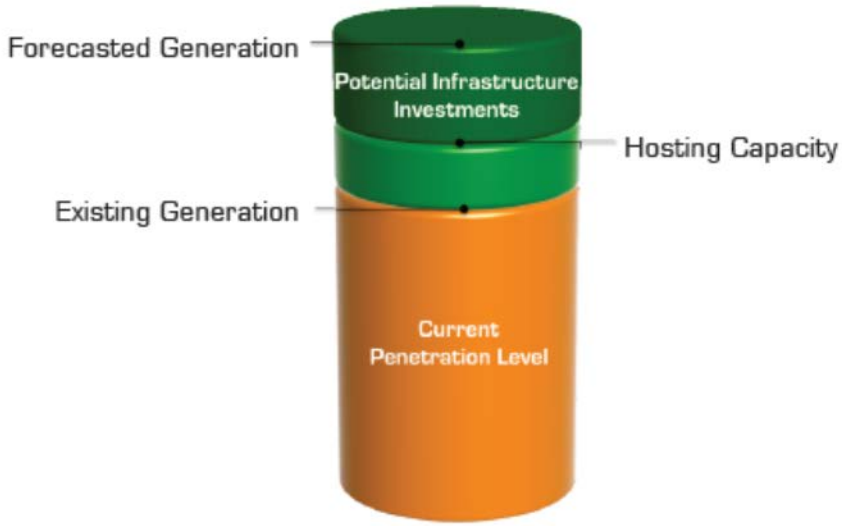

Figure 1 – Schematic illustrating hosting capacity and distribution system infrastructure investment required to increase hosting capacity. [6] *Note that hosting capacity in this schematic exceeds existing distributed generation, but that, once attained, can only be increased with investment in infrastructure.*

Expedited interconnection approval can usually occur if a so-called fast track screen is passed. Fast track screens serve as proxies for more technical assessment of an interconnection request if a DER is unlikely to trigger violations of voltage, thermal, and/or protection limits. Supplementary studies of DER interconnection impacts are typically required if a screen is not passed. Interconnection of low-impact electric power generation, such as distributed solar PV in an area with a low level of DER penetration, is usually expedited. Low penetration has frequently been defined as a distribution feeder or feeder line section with a total DER capacity of less than 15% of annual peak load.[7]

The so-called 15% screen is a capacity penetration measure; that is, it expresses total nameplate capacity of DERs interconnected with a distribution system feeder or feeder line section as a proportion of annual peak load on that feeder or line section. A rule of thumb for distribution planning engineers is that most distribution system feeders in the U.S. have minimum daily loads of approximately 30% of their annual peak loads; thus, the 15% screen is relatively conservative.[8] This screen was incorporated into California Public Utilities Commission (CPUC) Electric Tariff Rule 21 in year 2000. The 15% screen, however, fails to take into account the heterogeneity of feeders comprising distribution systems. Thus, in 2012 the CPUC

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[6] Figure from Interstate Renewable Energy Council, *Integrated Distribution Planning Concept Paper: A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources*, 12, 2013, http://www.irecusa.org/publications/integrated-distribution-planning-concept-paper/

[7] See Michael Coddington, Barry Mather, Benjamen Kroposki, et al., *Updating Interconnection Screens for PV System Integration (NREL/TP-5500-54063)*, 2, 2012, http://www.nrel.gov/docs/fy12osti/54063.pdf; Federal Energy Regulatory Commission, *Small Generator Interconnection Agreements and Procedures (Order No. 792)*, 70-85, 2013, http://www.ferc.gov/whats-new/comm-meet/2013/112113/E-1.pdf

[8] Coddington, Mather, Kroposki, et al., *supra* note 7, at 2.

added a supplementary screen to Rule 21 that, if passed, maintained a DER interconnection application on an expedited approval path. This supplementary screen, applied to an interconnection application that fails the initial 15% screen, requires DER penetration to be less than 100% of minimum daily load (i.e., 30% of annual peak load). Small DER projects such as solar PV generation, even if they fail the initial 15% screen, will often pass this supplementary screen.

Nonetheless, all such screens fail to account for the heterogeneity of hosting capacity; Text Box 1 below describes an example of a DER that fails both the 15% and 100% screens.[9] Determinants of hosting capacity include DER location on the feeder, feeder topology, design and operation, and DER technology.[10] Of these factors, DER location will be emphasized in this paper. With regard to feeder topology, design and operation, voltage class and load location are particularly important influences. Regarding DER technology, negative impacts may be compensated for using one or more advanced inverter functions. These so-called smart inverters can, for example, provide reactive power support and thereby reduce distribution system impacts of solar PV generation.[11] These determining factors can lead to DER hosting capacities that vary considerably and can exceed 15% (or even 30%) of minimum daily load. Figure 2 below, illustrating hosting capacities for feeder segments of a California IOU's distribution system, shows how DER location and feeder topology, design and operation affect hosting capacity.

Text Box 1 – An Interconnected DER that Fails the 15% and 100% Screens

In Fort Collins, Colorado, a university campus has a distribution system-interconnected solar PV generating system of 5.2 megawatts (MW), representing approximately 50% of the distribution feeder's annual peak load. Interconnection studies did not indicate significant negative impacts, but mitigating strategies are available if impacts arise. These strategies include adjusting voltage regulators on the feeder and using the solar PV system's inverter to absorb reactive power, thereby reducing feeder voltage.

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[9] Matin Braun, Thomas Stetz, Roland Brundlinger, et al., *Is the Distribution Grid Ready to Accept Large-Scale Photovoltaic Deployment?* Progress in Photovoltaics: Research and Applications 20, 692, 681-697, 2012.
[10] Electric Power Research Institute, *Integration of Hosting Capacity Analysis into Distribution Planning Tools*, 3, 2016, http://www.epri.com/search/Pages/results.aspx?k=integration%20of%20hosting%20capacity
[11] Richard McAllister, *Distributed Energy Resource Interconnection Timelines and Advanced Inverter Deployment: Their Improvement in the Western Interconnection*, 10, 2016, http://westernenergyboard.org/wp-content/uploads/2016/04/04-27-16_CREPC_WIRAB_mcallister_distributed_energy_resources_policy_whitepaper.pdf

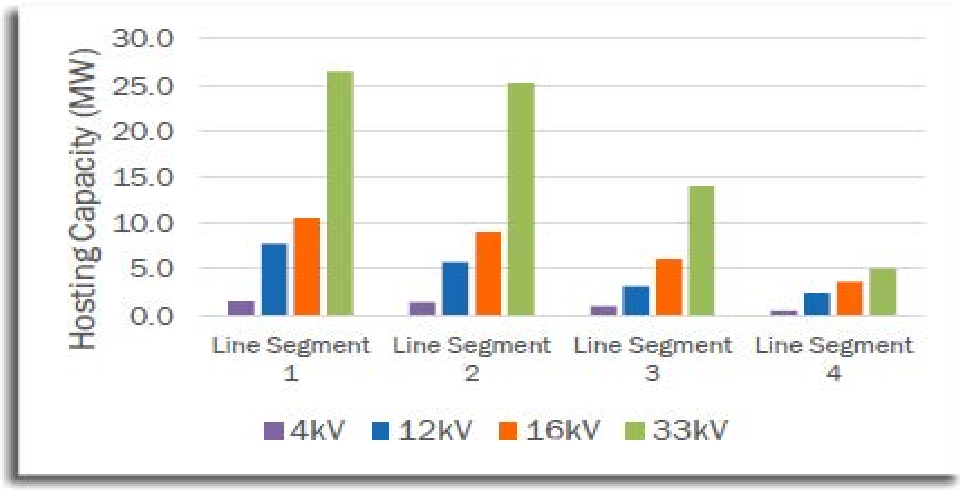

Figure 2 – Hosting capacity (in megawatts, MW) of segments of distribution system feeders of California IOU Southern California Edison.[12] *Influences of DER location (i.e., line segments 1-4) and feeder topology, design and operation (i.e., voltage classes 4-33 kilovolts (kV)) on hosting capacity are illustrated. Note that hosting capacity for any voltage class is highest for Line Segment 1 (i.e., segment most proximal to substation). Also note that hosting capacity increases with voltage class for any location (i.e., line segment).*

Given that fast track screens are overly conservative for some distribution feeders, Coddington and colleagues proposed short- and longer-term solutions.[13] Their three short-term solutions include using minimum daytime load as the denominator in capacity penetration screens, using supplementary screens when initial screens are failed, and employing utility-identified distribution system zones of penetration limits.

The first solution, expressing total DER nameplate capacity as a proportion of minimum daytime load, is a simple mathematical solution. In some areas, minimum daily load is the denominator in supplementary screening. Since minimum daily load often occurs in nighttime hours and is therefore lower than minimum daytime load, using the latter necessarily leads to a less conservative estimate of hosting capacity. Supervisory Control and Data Acquisition (SCADA) systems used by most utilities provide minimum daytime load values and may have data available for terms longer than a single year.

Coddington and colleagues provided examples of supplementary screens that can be employed if a DER interconnection application fails an initial 15% screen. In one of their examples, if the DER is a distributed solar PV generator and it passes voltage regulation and anti-islanding screens, as well as other technical impact screens, the DER's interconnection application may be expeditiously approved despite failing the 15% screen.[14]

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[12] Figure from PG&E, SDG&E, and Southern California Edison, *Integration Capacity Analysis Workshop: California IOU's Approach*, 7, 2015, http://www.cpuc.ca.gov/General.aspx?id=5071
[13] Coddington, Mather, Kroposki, et al., *supra* note 7, at 6-16.
[14] *Id.*, at 10-12.

The final short-term solution is to employ zones of penetration limits within a distribution system that are identified by the utility and are based on initial analysis by utility distribution planning engineers. As shown in Figure 2, areas closer to substations or those with low-impedance conductors (i.e., higher voltage classes) have greater DER hosting capacities. This solution will necessarily change over time as DERs are interconnected with feeders or line sections in a distribution system.

Coddington and colleagues also presented three longer-term solutions. One such solution is to develop more sophisticated metrics than DER capacity penetration measures; indeed, it is likely that each DER impact of concern requires a screening metric. As an example, an over-voltage impact metric would logically account for DER nameplate capacity, feeder impedance, and distance between the DER and its respective substation. The Electric Power Research Institute (EPRI), along with the National Renewable Energy Laboratory, Sandia National Laboratories, and California IOUs, has developed an approach that represents a streamlined, yet sophisticated, measure of hosting capacity that considers numerous impacts of interconnected DER.[15] It is likely that derived hosting capacities of feeders will differ depending on the impact examined. The EPRI approach is derived from actual feeder data.

Another longer-term solution is to upgrade distribution system feeders. Replacing feeder conductor with larger-sized (i.e., lower-impedance) conductor and installing voltage regulators are two examples of upgrades that can increase hosting capacity. Finally, advanced inverters and their capabilities represent potential solutions. Reactive power absorption, for example, can mitigate over-voltage impacts and thereby increase feeder hosting capacity.[16] Importantly, these advanced inverter capabilities can increase hosting capacities of existing feeders without the need for more expensive infrastructure upgrading. This is another example of how infrastructure costs can be avoided by leveraging DERs, a notion highlighted in the Introduction of this paper.

As noted above, intra-feeder DER location (i.e., line section of a given distribution feeder) is an important determinant of DER hosting capacity. DER hosting capacity also differs from feeder to feeder; that is, feeders exhibit inter-feeder heterogeneity. In studies of distributed solar PV generation in California, Cohen and colleagues used GridLAB-D modeling software to determine engineering and economic effects of distributed solar PV on distribution systems.[17] Results of these studies provide a bridge from the preceding examination of intra-feeder differences in hosting capacity to inter-feeder heterogeneity and locational value of DERs.

In the study that determined engineering effects, the investigators found that feeder location had more effects on engineering variables than feeder topology, design and operation. They used 8

[15] Electric Power Research Institute, *supra* note 10, at 5-7.
[16] McAllister, *supra* note 11, at 10.
[17] See M.A. Cohen and D.S. Callaway, *Effects of Distributed PV Generation on California's Distribution System, Part 1: Engineering Simulations*, Solar Energy 128, 126-138, 2016; M.A. Cohen, P.A. Kauzmann, and D.S. Callaway, *Effects of Distributed PV Generation on California's Distribution System, Part 2: Economic Analysis,* Solar Energy 128, 139-152, 2016.

representative feeders selected from more than 500 such feeders designated by GridLAB-D's developer, Pacific Northwest National Laboratory. These 8 different feeders were simulated using GridLAB-D for 3 California locations: Berkeley, Los Angeles, and Sacramento. These simulations therefore determined the influence of inter-feeder topology, design and operation (i.e., the 8 representative feeders) and inter-feeder location (i.e., the 3 California cities, with varying climates) on engineering variables. In addition, a series of 7 solar PV penetration levels, ranging from 0% to 100% of annual peak load, were tested. While feeder topology, design and operation influenced certain variables (e.g., magnitude of system losses), feeder location affected more variables, including peak loading, reverse power flow, and voltage quality (i.e., out-of-service-range voltage excursions[18]).[19] Feeder location effects on reverse power flow and voltage quality can be undesirable, whereas changes in peak loading due to location can be beneficial if peak loading is reduced. It is important to note that voltage quality effects were relatively small, with the worst case (1 of the 8 feeders simulated; for the Sacramento location, specifically) demonstrating out-of-service range voltages in less than 1% of simulation runs. For all 3 feeder location-dependent effects, effect size was greatest in Sacramento because of its sunny climate. Finally and interestingly, effects on most variables remained small with increasing distributed solar PV penetration, up to and including 100% penetration. These results provide some support for determining and utilizing locational value of DERs because inter-feeder heterogeneity in hosting capacity (specifically, due to geographic location) influenced both positive and negative impacts of DERs on distribution systems.

In the study that determined economic effects, Cohen and coworkers determined distributed solar PV generation's impacts on distribution system costs. Similar to their engineering study, they simulated 8 representative feeders for 2 California locations – Berkeley and Sacramento. Distribution system data from the IOU serving these two locations, PG&E, were also used in analyses. The average distribution system capacity project deferral value of approximately $6/kilowatt-year (kW-year) across all feeders of the PG&E service territory was low relative to the cost of distributed solar PV generation.[20] Nonetheless, there was a small subset of feeders (those requiring capacity projects within 10 years, representing approximately 10% of all feeders) for which capacity deferral value was $10-60/kW-year. For PG&E's entire distribution system, the investigators calculated that if all PG&E feeders had 100% distributed solar PV penetration, there would be a distribution system capacity project deferral value of $30-40 million per year. The principal operations and maintenance cost associated with high distributed solar PV deployment, that associated with voltage regulators, was estimated by the investigators to be less than $0.5 million per year at 100% penetration.[21] Thus, in considering global

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[18] Jack Casazza and Frank Delea, *Understanding Electric Power Systems: An Overview of the Technology, the Marketplace, and Government Regulations,* 116, 2010. Nominal distribution voltage levels in distribution systems range from 4 to 34 kilovolts (kV), with 13 kV being most common.
[19] Cohen and Callaway, *supra* note 17, at 128-129, 129-130, 132.
[20] Cohen, Kauzmann, and Callaway, *supra* note 17, at 145, 148. This value of $6/kW-year compares unfavorably with a cost of distributed solar PV generation of approximately $380/ kW-year (2012 cost).
[21] *Id.*, at 148.

distribution system benefits, there was a large net benefit in deploying distributed solar PV generation within the PG&E system. The investigators opined that compensation for distributed solar PV's locational value could be an effective strategy for the subset of distribution system feeders with relatively high capacity project deferral value. It bears reiterating, however, that capacity project deferral value for a majority of feeders was relatively low. These findings also indicate that locational value of DERs is influenced by hosting capacity and by deferral value.

As noted in the Introduction of this paper, there have been actual transmission and distribution system capacity project deferrals totaling nearly $200 million in PG&E's service territory. These deferrals were attributed to distributed solar PV generation and energy efficiency measures.[22] Significantly, the underlying additions in solar PV generation were neither proactive nor targeted. Thus, using locational value to proactively add DERs may lead to even greater deferral of distribution system capacity projects.

State Initiatives Related to Locational Value – California

DERs have only recently made significant contributions to the grid, so little consideration has typically been given to where they are located in distribution systems. Lack of consideration of heterogeneity in locational value, however, appears to be ending in certain states. California, a state that has experienced accelerating annual solar PV deployment, has ongoing proceedings in which hosting capacity and deferral value of DERs are being considered. New York, a state with lower DER growth than California, is more proactively considering DER value with respect to both hosting capacity and deferral value. We will first examine initiatives in California.

Given California's ambitious renewable portfolio standard (50% by year 2030), as well as the potential for DERs to contribute to compliance with this standard, the CPUC has initiatives to increase deployment of DERs. Two key initiatives are Rulemaking 14-08-013, the Distribution Resources Plan (DRP) proceeding,[23] and Rulemaking 14-10-003, the Integrated Distributed Energy Resources (IDER) proceeding.[24] CPUC Commissioners Picker and Florio are the Assigned Commissioners for the DRP and IDER proceedings, respectively.

The DRP proceeding. Although this proceeding was initiated in 2014, related policies date back to 2001. The CPUC has long-encouraged consideration of non-utility-owned DERs as alternatives to distribution system investments to ensure lowest-cost electric power. The CPUC has also encouraged increases in aggregate DER nameplate capacity to reduce GHG emissions. As an example, the California Solar Initiative General Market Program, begun in 2007, had a

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[22] Pyper, *supra* note 3.
[23] Proceeding documents available at: http://www.cpuc.ca.gov/General.aspx?id=5071 (last visited August 25, 2016).
[24] Proceeding documents available at: http://www.cpuc.ca.gov/general.aspx?id=10745 (last visited August 25, 2016).

goal of 1750 megawatts (MW) of customer-installed solar PV nameplate capacity by year 2017; that goal was met by the end of 2015, a full year ahead of schedule.[25]

The 2014 DRP proceeding was required by Section 769 of the Public Utilities Code, which was added by California Assembly Bill 327 (AB 327). AB 327 was passed due to recognition that traditional distribution system planning was not consistent with state policies on DERs and GHG emissions. Importantly, Section 769 requires California IOUs to propose DRPs that identify ". . . optimal locations for the deployment of distributed resources."[26] In evaluating location-specific benefits and costs of DERs, Section 769 specifies that criteria such as reductions (or increases) in local generation capacity needs and reductions (or increases) in investments in distribution infrastructure should be considered.[27] Section 769 therefore requires balancing modernization of the distribution grid and minimization of investment in it, while simultaneously adding DERs to reduce GHG emissions, a non-trivial challenge for the power sector in California.

The purpose of the DRP proceeding is to assist California IOUs with proposing DRPs by establishing policies, procedures and rules. In support of that purpose, Commissioner Picker introduced a ruling in February, 2015 that provided guidance on content and structure for California's first-ever DRPs.[28] These DRPs had a July 1, 2015 submission deadline. Going forward, biannual DRP submissions are anticipated.

The following topics were specified by Commissioner Picker to be addressed in IOU DRPs:

● Integration capacity and locational net benefit analyses

● Demonstration and deployment of integration capacity and locational net benefit analyses

● Data access

● Tariffs and contracts

● Safety considerations

● Barriers to deployment

● DRP coordination with utility general rate cases

● DRP coordination with utility and CEC load forecasting

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[25] California Public Utilities Commission, *California Solar Initiative: Annual Program Assessment*, 10-11, 2016, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/2016%20CSI%20APA%20FINAL.pdf
[26] West's Ann. Cal. Pub. Util. Code § 769
[27] *Id.*
[28] California Public Utilities Commission, *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning (Rulemaking 14-08-013)*, 2015, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF

● Phasing of next steps

The first of these topics - integration capacity analysis (ICA) and locational net benefit analysis (LNBA) – is most related to this policy paper. ICA is synonymous with determination of DER hosting capacity. California IOUs were required to provide hosting capacity values, to feeder line section resolution, in their DRPs. The CPUC anticipated that ICA would include consideration of feeder thermal limits, protection system limits, and power quality and safety standards.[29] ICA is, therefore, an improvement over the fast track screens typically used to estimate hosting capacity (see above). Results of ICA were to be made publicly-available in online maps; Figure 3 below is a portion of one such map developed by the IOU San Diego Gas & Electric (SDG&E). SDG&E used Synergi software, which it employs for distribution planning, to conduct its ICA.[30]

Figure 3 - Portion of SDG&E service territory, from publicly-available DRP map.[31] Red lines, Zone 1 of feeders (most proximal to substation); blue and green lines, Zones 2 and 3 of feeders. Substation is located northwest of Del Mar Golf Center in southern area of map, immediately west of Highway I-5. Pop-up box from Zone 3 of feeder

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[29] *Id.*, at 3 (of Attachment).

[30] San Diego Gas & Electric, *Application of San Diego Gas & Electric Company (U 902 E) for Approval of Distribution Resources Plan*, 21-22, 2015, http://www.cpuc.ca.gov/General.aspx?id=5071

[31] DRP maps available at: http://www.sdge.com/generation-interconnections/interconnection-information-and-map. To access maps, scroll to the Accessing the Map section of webpage. Note that one must obtain a username and password to access DRP maps (last visited August 30, 2016).

in northwestern area of map provides several variables for that feeder, including feeder capacity (Circuit_ Ca; 3.50) and hosting capacity (ICA_DRP; 2.50). Values for feeder and hosting capacities are in megawatts.

SDG&E, in developing its DRP, used aggregate DER capacity that resulted in reverse power flow to determine hosting capacity. Reverse power flow occurs when DER-generated power flows to its distribution feeder's substation bus.[32] Although hosting capacity determination of all distribution feeders was incomplete at the time that SDG&E submitted its DRP, approximately 100 MW of available hosting capacity had already been identified. This value was expected to increase to more than 1000 MW upon completion of ICA of the entire SDG&E distribution system.[33] Interestingly, and per the recommendation of Coddington and coworkers,[34] SDG&E conducted its analyses of feeders in zones determined by distance from their substations. Zones most proximal to substations were determined to have the highest hosting capacities by SDG&E.[35] Figure 4 below illustrates an example from the DRP filed by SDG&E in 2015.

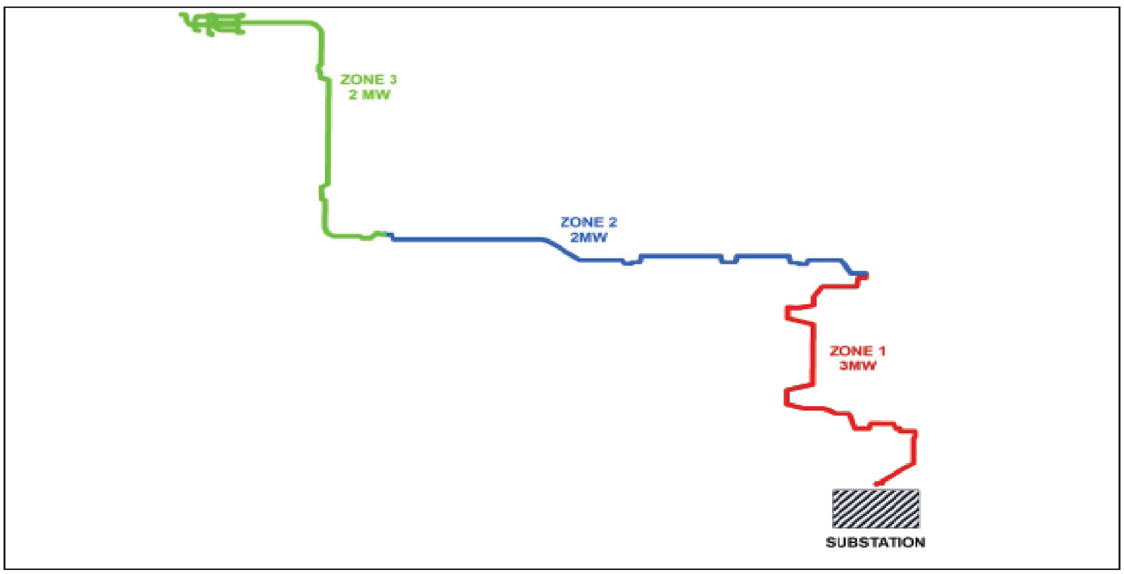

Figure 4 – Example of feeder divided into three zones, Zone 1 being most proximal to substation.[36] Values are hosting capacities, in megawatts (MW). Note that highest hosting capacity is associated with Zone 1. The minimum daily load for this feeder is 5 MW; thus, aggregate DER nameplate capacity for feeder cannot exceed 5 MW, although potential aggregate hosting capacity is 7 MW.

LNBA refers to determination of net benefit of DERs at a given location within a distribution system. In this determination, costs of any distribution system upgrades necessary for DER interconnection (e.g., those needed to permit two-way power flow) are necessarily accounted for. SDG&E proposed two categories of distribution system investments, one for which DERs can

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[32] San Diego Gas & Electric, *supra* note 30, at 22.
[33] *Id.*, at 22.
[34] Coddington, Mather, Kroposki, et al., *supra* note 7, at 12-13.
[35] San Diego Gas & Electric, *supra* note 30, at 23-27.
[36] *Id.*, at 27.

avoid distribution investment and one for which DERs do not constitute an alternative to distribution investment. An example of the latter category is re-conductoring of distribution feeders.[37] The CPUC anticipated that LNBA would be conducted using the CPUC-approved DER Avoided Cost (DERAC) Model that was developed by the consultancy E3.[38] This model determines time- and location-specific avoided costs with energy efficiency, distributed generation, and demand response programs. DERAC was to be supplemented with various enhancements in DRPs. These enhancements were to include location-specific values for certain variables (e.g., generation energy; to be replaced by locational marginal pricing), as well as a list of eight value components (e.g., avoided sub-transmission, substation and feeder capital expenses and their associated operating expenses). These enhancements and value components reflect, for example, the benefit of DERs reducing net loading impacts on distribution infrastructure. In a subsequent ruling Commissioner Picker, at the request of California IOUs, issued refined guidance on enhancements to DERAC. As an example, DERAC's single category of avoided transmission and distribution expenses was replaced with four categories of expenses: avoided capital and operating costs for transmission systems, avoided capital and operating costs for sub-transmission systems and substations, distribution system reliability, and distribution system power quality.[39]

The IDER proceeding. This proceeding has evolved since it was initiated in 2014. Similar to the DRP proceeding, it concerns the distribution system and DERs. The IDER proceeding's scope was expanded in 2015 ". . . to consider a framework based on the entire energy production and delivery system from the customer side to the utility side."[40] In April of 2016, a draft ruling was introduced by Commissioner Florio that considered the issues of utility role, business model, and financial interest, all in relation to DER deployment, and developed a general methodology for calculating incentives for DER deployment.[41] Given this ruling's preliminary nature, it will not be described further here; details of the Florio draft ruling are provided in Appendix B. .

State Initiatives Related to Locational Value - New York

Similar to California, the state of New York's electric power sector is undergoing change. New York's Reforming the Energy Vision (REV) strategies include promoting energy efficiency, increasing electric power generation from renewable resources, increasing deployment of DERs,

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[37] *Id.*, at 39.

[38] This calculator is available at: https://ethree.com/public_projects/cpuc5.php (last visited June 9, 2016).

[39] California Public Utilities Commission, *Assigned Commissioner's Ruling 1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and 2) Authorizing Demonstration Projects A and B*, 25, 2016, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF

[40] California Public Utilities Commission, *Assigned Commissioner's Proposed Decision Adopting an Expanded Scope, a Definition, and a Goal for the Integration of Demand Side Resources*, 2, 2015, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M154/K464/154464227.PDF

[41] California Public Utilities Commission, *Assigned Commissioner's Ruling Introducing a Draft Regulatory Incentives Proposal for Discussion and Comment (Rulemaking 14-10-003)*, 2016, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K702/159702148.PDF

and using power storage. Among New York's environmental goals are a 40% reduction in GHG emissions and a clean energy standard of 50% of electric power generation from renewable resources, both by year 2030.[42] Both goals are related to the REV strategy of increasing deployment of DERs because it is anticipated that distributed solar PV generation will contribute approximately 3600 gigawatt-hours of GHG-free, renewable resource-derived power by year 2023.[43]

In late 2015, due to the importance of the DER strategy of REV, the New York Public Service Commission (PSC) issued a notice requesting comments and proposals on an interim successor to New York's current net-energy metering (NEM) scheme that compensates DER owners for power exported onto the grid. Although the title of this notice indicates that its primary purpose was to address NEM, a secondary purpose was to address the valuation of DER location.[44] A group of New York IOUs and solar developers, the so-called Solar Progress Partnership, filed comments in response to the notice. The Partnership includes Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Rochester Gas and Electric, Solar City, SunEdison and SunPower. While the Partnership's comments on NEM are beyond the scope of this paper, it also included a proposed ". . . mechanism to move to a more geographically targeted incentive for those resources that provide distribution benefits."[45] This mechanism is to be imbedded in the following formula that determines the Solar Progress Partnership's alternative to full retail rate NEM compensation:

Alternate compensation = LMP + D + E

where LMP is location-based marginal pricing (comprised of wholesale power compensation, transmission congestion charges, and transmission line loss compensation), D is value brought to the distribution system by DERs (e.g., deferral of capital investments in the distribution system), and E encompasses societal benefits of DERs (e.g., GHG emission reductions). It is anticipated

[42] See http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument (last visited June 14, 2016); New York Department of Public Service, *Staff White Paper on Clean Energy Standard (Case 15-E-0302)*, 1, 2016, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument

[43] See New York Department of Public Service, *supra* note 42, at 2; Solar Progress Partnership, *Comments of the Solar Progress Partnership on an Interim Successor to Net Energy Metering*, 4, 2016, http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0751&submit=Search+by+Case+Number

[44] New York Public Service Commission, *In the Matter of the Value of Distributed Energy Resources: Notice Soliciting Comments and Proposals on an Interim successor to Net Energy Metering and of a Preliminary Conference (CASE 15-E-0751)*, 2, 2015, http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0ahUKEwjvmoH5sKXNAhUF1R4KHQp1DrUQFggcMAA&url=http%3A%2F%2Fdocuments.dps.ny.gov%2Fpublic%2FCommon%2FViewDoc.aspx%3FDocRefId%3D%257B72C65039-EC54-497A-8D4A-FD0636512C10%257D&usg=AFQjCNE15r7ejlNzzs6pkpDp7rHvxYgbxQ

[45] Solar Progress Partnership, *supra* note 43, at 3.

that DER locational value will be primarily captured in the LMP term of the formula.[46] The Solar Progress Partnership has proposed that DERs would be categorized into blocks which would be, in turn, organized in declining order of locational value. Each succeeding block would have its NEM compensation reduced more rapidly toward LMP + D + E.[47]

The New York PSC, similar to the CPUC, will require distributed system implementation plans (DSIPs) from New York IOUs.[48] These DSIPs are expected to identify beneficial locations for DER deployment by specifying where DERs can be substituted for traditional infrastructure investment, thereby deferring or avoiding certain utility capital and operating costs.[49] Identification of beneficial locations for DER in DSIPs was required in part because a 2015 analysis conducted for the PSC indicated that, absent targeting of DERs to higher-value distribution system locations, the total benefit-to-cost ratio was less than unity (i.e., costs exceeded benefits). On the other hand, a benefit-to-cost ratio of greater than unity (i.e., benefits exceeded costs) was associated with targeting to higher-value locations.[50] DSIPs are proposed to be submitted in two filings, the first of which (so-called Initial DSIPs) were due on June 30, 2016. Initial DSIPs were to be principally self-assessments that used existing information. Later, Supplemental DSIPs with detailed tools, processes and protocols will be filed.[51]

More generally, the New York PSC is proceeding with actions to better align utilities' interests with those of ratepayers. A key element in this alignment is expanding utility revenue opportunities beyond those associated with cost-of-service ratemaking. A recent New York PSC order creates so-called platform service revenues that will be earned by utilities that displace traditional distribution infrastructure projects with DER alternatives.[52]

Policy Options

Hosting capacity and its use in DER interconnection screening, due to its maturity, is more straightforward for which to provide policy options. Valuation of DER location is in its infancy, and is therefore more challenging for which to propose policies. We offer the following:

● Interconnection screening usually consists of simple capacity penetration measures that are generally conservative. These simplistic and potentially inaccurate capacity penetration

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[46] *Id.*, at 7.
[47] *Id.*, at 15-16.
[48] New York Department of Public Service, *Staff Proposal: Distributed System Implementation Plan Guidance,* 2015, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument
[49] *Id.*, at 10, 14-15.
[50] E3, *The Benefits and Costs of Net Energy Metering in New York*, 1-9, 2015, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF4166D6E-CBFC-48A2-ADA1-D4858F519008%7D
[51] New York Department of Public Service, *supra* note 48, at 4.
[52] New York Public Service Commission, *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (CASE 14-M-0101)*, 24, 2016, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument

measures can be exacerbated by inaccurate load values. Screening should immediately transition to an initial capacity penetration measure supplemented with key DER impact screening metrics. Longer-term, screening should employ more sophisticated approaches such as determining hosting capacities for each of multiple negative DER impacts such as over-voltage deviations. These improvements in interconnection screening should be implemented prior to anticipated increases in interconnection request numbers.

● Regulators should consider requiring utilities to make hosting capacity data publicly-available. This would enable developers to deploy DERs at more appropriate locations in distribution systems, thereby avoiding costly supplementary studies for interconnection requests. Interconnection of more DERs would therefore be facilitated.

● Hosting capacity analysis should be used to guide DER deployment because DERs can be located on feeders or feeder line sections with available hosting capacity. In addition, distribution system capacity projects may be deferred by instead deploying DERs if a net benefit (from benefit-cost analysis) is derived. Locational value is influenced by both hosting capacity and distribution system capacity project deferral value, and it should be used to guide DER deployment rather than only hosting capacity.

● Incentives to defer or even avoid distribution infrastructure investment by instead deploying DERs, if a net benefit is present, should be considered. Such incenting of DER deployment will, however, require consistent methodology for determining DER locational value.

Appendix A – Tables

	Benefits of DERs	Costs of DERs
Infrastructure-related	*Avoid or defer need to build conventional generation*	
	Avoid or defer need to invest in building or upgrading of transmission or distribution equipment	*Distribution equipment upgrading may be required to accommodate two-way power flow*
Energy-related	Avoid fuel consumption of conventional generation	
	Reduce utility exposure to fuel price volatility	
	Avoid transmission and distribution system power losses	
Environment-related	Reduce costs of meeting environmental standards for criterion pollutants and GHGs	Program administrative costs (e.g., incentives) may be required
	Reduce costs of meeting RPSs	
	Avoid use of and impacts on water	
Other	Provide ancillary services (e.g., frequency response)	Provision of ancillary services may involve additional costs
		Management of increased reliability risk (e.g., availability of flexible generation)

Table 1 – Benefits and costs of distributed energy resources (DERs).[53] *GHGs, greenhouse gases; RPSs, renewable portfolio standards. Benefits and costs in italics are those emphasized in this paper.*

[53] Benefits and costs adapted from those of Lena Hansen, Virginia Lacy, and Devi Glick, *A Review of Solar PV Benefit and Cost Studies,* 13-17, 2013, http://www.rmi.org/search-rmi

	ConEd	PG&E
Service territory	New York City, Westchester County	Central, Northern California
Customer number	3.3 million	5.1 million
Utility type	Primarily distribution	Vertically-integrated
Distribution system configuration	Network; underground	Radial; above-ground
Peak load (MW)	16,773 (2015)	23,684 (2014)
Interconnected DERs (MW)	259	3000-3500

Table 2 – Comparison of IOUs Consolidated Edison (ConEd) and Pacific Gas & Electric (PG&E). MW, megawatt; DERs, distributed energy resources.

Appendix B – CPUC Draft Proposal in the IDER Proceeding

The financial interest issue underlying CPUC Commissioner Florio's draft proposal is that IOUs earn a rate of return on capital investments in utility infrastructure such as distribution systems. Thus, if distribution system investment is deferred by procurement of DER services, no incremental return on that deferred investment is earned. The draft proposal identifies this potential conflict with an IOU's financial interest when requesting an IOU to defer distribution system investments by procuring DERs, as is the case in the DRP proceeding. In order for the CPUC's encouragement of DER deployment to be harmonized with an IOU's financial interest, Commissioner Florio's proposal involves a pilot regulatory incentive structure and process that fits within the traditional cost-of-service regulatory model. The Florio proposal also aligns with a key financial motivator for an IOU – increasing shareholder value.

Corporate finance principles dictate that shareholder value is driven by the difference between a corporation's return on equity and the cost of equity,[54] such that:

$Value = r - k$

where r = return on equity and k = cost of equity. In order for an IOU to create value for shareholders when making capital investments, r must be greater than k; if these two variables are equal, an IOU will not create incremental value and therefore be indifferent to capital investment. As noted in the draft proposal, current values for authorized return on equity are approximately 10%, while cost of equity (i.e., the return that investors expect) is roughly 7.5%. In California, specifically, the difference between r and k has ranged from 2.5% to 3.5% in recent years. Thus, the draft proposes that the regulatory incentive for IOUs to defer distribution system investment via procurement of DERs to be a value for $r - k$ of 3.5%. This return rate of 3.5% would apply to expenses incurred in procuring DERs. Furthermore, it is proposed that, given distribution system complexity, IOUs (rather than the CPUC) determine optimal locations for DER service procurement in lieu of distribution investment. Utility benefit – cost analysis to support such determinations will depend heavily on locational value of DERs, as noted in the DRP proceeding sub-section of this paper. It should be noted, however, that several parties, have filed comments contrary to the Florio proposal.[55]

The draft proposal also details the process for procuring DER services. In Stage 1, each of California's IOUs would identify cost-effective DER deployment locations in its distribution

[54] See Steve Kihm, Andrew Satchwell, and Peter Cappers, *The Financial Impacts of Declining Investment Opportunities on Electric Utility Shareholders (LBNL-1005828)*, 2016, http://eetd.lbl.gov/publications/the-financial-impacts-of-declining-in; Steve Kihm, Andrew Satchwell, and Peter Cappers, *The Effects of Rising Interest Rates on Electric Utility Stock Prices: Regulatory Considerations and Approaches (LBNL-1003952)*, 2015, http://eetd.lbl.gov/publications/the-effects-of-rising-interest-rates-

[55] Lawrence Kolbe and Michael Vilbert, *Moving Toward Value in Utility Compensation : Shareholder Value Concept*, 2016, http://www.cpuc.ca.gov/General.aspx?id=10745 This presentation is an example of several such presentations made to the CPUC during an IDER proceeding workshop that argued that r is not routinely set to a value greater than k in order to induce utilities to make non-capital investment expenditures.

system. In Stage 2, an IOU would submit an advice letter in which DER procurement would be proposed. In addition to specifying DER location, the distribution system issue (and an estimate of its cost) that the DER procurement would address would be described. Also included would be a plan for DER procurement that would invite affected utility customers, as well as vendors and aggregators, to offer DER services. Vendors and aggregators could, for example, rent rooftops from customers. Stage 3 would involve a public workshop in which details of the Stage 2 advice letter would be presented. Stage 4 would consist of a comment/protest period. Stage 5, assuming approval of the advice letter by the CPUC, would be a solicitation for DER services. Finally, in Stage 6, resultant contracts for DER provision would be submitted by an IOU for CPUC approval. The entire pilot program is projected to be two years in duration.