I. Introduction


Established in 1974, SEIA is the national trade association of the United States solar energy industry and is a broad-based voice of the solar industry in Illinois. Through advocacy and education, SEIA and its 1,000 member companies are building a strong solar industry to power America. There are 34 SEIA member companies in operation in Illinois working in all market segments – residential, commercial, community solar, and utility-scale – representing millions of dollars of in state investment and a significant portion of Illinois’ 4,000 solar jobs. SEIA member companies also provide solar panels and equipment, financing, and other services to a large portion of Illinois solar projects. Established in 1975 ISEA, which has approximately 600 business and individual members, educates and advocates for the advancement of solar development in Illinois. The Coalition for Community Solar Access is a national Coalition of businesses and non-profits working to expand customer choice and access to solar for all American households and businesses through community solar.

The Joint Solar Parties have board collective knowledge and experience through participating in Distributed Energy Resources (DER) valuation proceedings around the country. We look forward to working with the ICC and other stakeholders to develop long-term solutions that adequately value the benefits that DERs bring to Illinois residents and the grid in general.

A. Overarching Goals and Objectives

Establishing protocols for properly valuing the benefits of distributed energy resources (“DERs”), and devising ways to unlock those benefits, is not a simple task. Public Act 99-0906 created a multi-tiered process to provide full value to DERs. Some of those aspects, including the value of Renewable Energy Credits (RECs) and net metered supply, have been handled in other contexts (e.g. ICC Docket No. 17-0838 (LTRRPP approval); ICC Docket No. 17-0350 (ComEd community solar tariff).) In anticipation of approval of a tariff pursuant to Section 16-107.6(e) of the Public Utilities Act, this informal process addresses a specific subset of these overall values, specifically the value “to the grid.” (See 220 ILCS 5/16-107.6(b), (e).)

This process is both similar to and distinct from other states. On one hand, efforts are underway in a number of states to determine the value that solar provides to the grid and consumers, but as yet they remain largely in the early stages. At issue are not only the methods by which DER benefits are calculated, but also the processes used to establish and refine discrete elements; the designs of tariffs and programs through which the values flow, how these aspects affect the marketplace for DERs, DER customers, non-DER customers, and utilities, and the overall state policy context. On the other hand, some of the jurisdictions considering value of solar are either
vertically integrated or address most (if not all) values of solar through the utility. Neither experience can be simply superimposed on Illinois, although other jurisdictions have had to address the issues related to values to “the grid” that Illinois will have to address. This DER valuation process should be considered one piece of an overall puzzle to allow and encourage DER market development in Illinois.

Given the wealth of issues that must be considered, the Joint Solar Parties believe it is critical that Illinois first establish core objectives for its DER valuation framework as a guide for future decisions.

**Illinois Supports Expanding Distributed Generation**

In its Resolution initiating the ‘NextGrid’ Grid Modernization Study, the Commission recognized the pace of change being brought about by distributed degeneration and related technologies, the need for Illinois’ electric industry and regulatory processes to evolve to meet the many challenges presented by this evolving industry, and the promise of even greater future consumer and societal benefits as the electric system moves towards the integration of distributed energy resources. The Resolution envisions the NextGrid report to lay out issues, opportunities and challenges, identify areas of consensus and disagreement, and provide a range of recommendations aimed at empowering customers, driving economic development, optimizing the electric utility industry, and creating a 21st Century regulatory model that supports innovation.

Just as the work Illinois has done to unlock competition in the electric industry has evolved and yielded benefits over the past two decades, this next wave of regulatory reform and market development will also evolve over the next two decades. The NextGrid report will help regulators and other policymakers map out the work needed to reach the ultimate goals.

This Value of DG proceeding, and the subsequent tariff, should be viewed in the context of Illinois’ overall vision of evolving a 21st Century regulatory model, its desire to dramatically grow new solar installations – and the corresponding economic development – and its stated desire to maintain its leadership in energy policy and its goal of enabling customers to better manage their energy use and control its cost. The tariff to be in place upon reaching the 5% net metering cap should be viewed as an early step in this long evolution.

The Future Energy Jobs Act (FEJA) and Illinois’ NextGrid proceeding both recognize that our electricity grid is evolving. Markets should be transparent and the market signals must be clear to all participants.

After FEJA, both the Illinois Power Agency Act and the Public Utilities Act make clear the directive and mandate to the Commission to support new development of solar resources, including distributed solar resources. Section 1-75(c)(1)(C) directs the Illinois Power Agency by 2030 to procure 2,000,000 RECs annually from distributed and community renewable generation powered by PV solar that was built after June 1, 2018.  (See 20 ILCS 3855/1-75(c)(1)(C).) The new build wind and solar requirements—including the 2,000,000 annual RECs from distributed and community renewable generation powered by PV solar—explicitly take precedence over the top-line RPS requirements. (See 20 ILCS 3855/1-75(c)(1)(B).) In order to put the Illinois Power Agency in the best position to meet these goals, the value of PV solar DERs must be fairly
compensated. Indeed, fully enabling this emerging market to grow and scale will be critical to realizing the many benefits sought by NextGrid.

We must ensure the grid framework incorporates the full value of consumer-centered resources and technologies and provide a pathway for DER-enabled grid solutions we can’t yet imagine. These DER assets stay connected to the utility system and the two work together to produce a more reliable, resilient, low-carbon energy system. DERs should be viewed as an opportunity. We should welcome and encourage power created by the people, for the people and create structures that allow the market to develop.

**DERs Provide a Wide Range of Services to the Grid**

Value to the grid is a new area of interest for utilities and distributed energy resources alike, there are a host of services DERs like solar and solar+storage (a single system that combines solar and storage) can provide. These services do not need to be activated all at once, and the value of DER tariffs should contemplate how these assets are activated and valued over time. The system owner must be fairly compensated for the additional benefits offered to the grid. Grid services can include, but are not limited to:

- **Versatile demand response** participation that avoids transmission and distribution line losses.
- **Localized distribution support** programmed for specialized load shifting, variable by month/day/hour, to support targeted load shift or voltage support.
- **Increased renewables hosting capacity** to reduce risk of backfeed and enable higher renewables and electric vehicle penetration.
- **Real-time data sharing** on asset performance, customer loads, and local grid attributes monitored via revenue-grade metering.

To evaluate the identified compensation structure options, we encourage the ICC to first develop criteria and objectives to help guide the creation of DER valuation structure.

**Foundational Goal and Principles**

As discussed in further detail throughout the body of these comments, the chief goal should be supporting sustainable, long-term, and stable DER market development through the realization of the full benefits DERs can provide. We identify the following objectives and principles as essential to achieving this goal.

1. **Ensuring Financeability**: Neither the full benefits of DERs, the full 2,000,000 RECs annually required by Section 1-75(c)(1)(C) of the IPA Act nor the ultimate vision expressed in the Resolution initiating the NextGrid proceeding will be realized under conditions where deployment is frustrated by uncertainty over compensation for DER benefits. Of central importance in this respect is that DERs have a capital structure much more like traditional utility grid investments, like a substation or a distribution line, than fossil fuel generating plants. Specifically, DERs (and grid assets) tend to be characterized by large up-front capital costs and relatively smaller ongoing costs such as operations and maintenance.
Scaling DERs therefore requires financing, the availability of which in turn hinges on the establishment of long-term, stable economic signals to providers, and predictable compensation for customers.

While the exact definition of ‘financeability’ may vary depending on the customer and project type (residential rooftop solar system or a community solar developer), financing for all customers requires predictability and long-term stability.

Apart from revenue predictability, a central element of ensuring financeability is setting a long-term price signal up front, so the developer and their financing partner(s) have clear vision into the long-term revenue stream. This is comparable to the difference between having a long-term PPA compared with selling into the hourly market, or even short-term contracts in the bilateral market. The PPA approach is similar to setting the price of the value of DER at the time of planning and construction—again, just as distribution grid components are compensated—rather than having the potential upside coupled with unpredictability and risk of a constantly-changing revenue stream. Additionally, existing systems should be able to ‘opt in’ to any new technical requirements (and associated revenue streams) after the initial rebate is issued.

2. Creating Market Stability & Predictability: Illinois law places certain constraints (discussed further in subsequent sections) on the timeframe for the development and deployment of a methodology for determining the distribution value of DERs. In order to support a smooth transition to the beginning of a new value-based regime, the development of the methodology and character of value-based compensation needs to display a sense of urgency so that it can be deployed and implemented in line with statutory requirements, and DER providers and prospective customers can adequately prepare for it.

Additionally, consumer protection should be kept front-of-mind in considering market stability. If consumers can’t understand complicated new rates and respond to them appropriately, their financial well-being is jeopardized. Because of these constraints, a smooth transition that consists of smaller, reasonable changes in a stepped process is appropriate.

Additionally, even during conversations of new methodologies to value DERs, a customer’s right to offset and manage their own load should be protected.

3. Evolution Over Time: The Commission should recognize that objectives (1) and (2) necessitate that the framework embody an evolutionary character that supports both timely implementation, as needed, and gradual refinement as more and better information becomes available. As evidenced by similar efforts taking place in other states, developing a finely tuned, locally-differentiated valuation methodology is a time-consuming process – and one which has not been demonstrated in any state to date. It demands extensive collaboration between stakeholders and is often frustrated by a lack of data suitable for establishing reliable valuations. In addition to allowing for refinement, it allows for consideration of impacts based on customers. Developers and their customers need simple, easy to understand value of solar price signals, and they need time to adjust to market signals. Moreover, transitioning to a service or value-based regime requires a fundamental rethinking of the distribution planning process which itself is a long-term process.
As discussed previously, this DG tariff fits within the overall NextGrid proceeding - it is one mechanism that the Commission has to implement NextGrid. And it is a mechanism that will need to evolve over time (for new systems) with early forms having placeholders for data that we do not have yet – either because utilities do not currently collect it in a useable and shareable format or because such data is not yet knowable due to the yet-to-evolve distribution planning and utility business models.

Furthermore, when considering how the DG Value tariff – both the structure and value – will impact the further development of solar in the state, the Commission should apply the principle of gradualism in its decisions.

4. Transparent and Participatory Processes: Developing valuation methods is a highly technical exercise that demands extensive stakeholder collaboration and expert input. Working group formats, as have been used in other states, can be an effective way to develop proposed methods and accomplish related goals (e.g., defining data availability and needs). However, their effectiveness is compromised when they lack formal mandates or backing, or clear objectives, deliverables, timelines, and effective facilitation. We recommend that one or more working groups be established, consistent with the characteristics described above, for the purpose developing valuation proposals and that these working groups be overseen by a neutral facilitator who reports to the Commission. The working group proposals can then be presented for party comment in a more formal setting. It is critical that the groups be backed by a mandate that utilities be full participants obligated to work collaboratively with stakeholders and fully share information and data necessary for the group to accomplish its tasks.

5. Valuation Must Use a Long-Term Perspective: The valuation methodology itself must reflect a long-term perspective consistent with the operating lifetime of DERs. DERs that function as replacements for other long-term investments generate value throughout their lifetime. Evaluating their value based on a more limited time horizon is inconsistent with how a comparable traditional infrastructure investment would be valued.

The need for long-term values was recently recognized by the California Public Utilities Commission (CPUC), which is the most advanced in developing locational values. In Decision 17-09-026 the CPUC determined that distributed energy resources had distribution level benefits beyond the utilities’ distribution planning horizon and that those long run benefits needed to be accounted for in determining the value of a distributed energy resource at any location on the distribution grid. Illinois similarly should adopt a long-term approach to fully compensate the value in deferring or replacing distribution system upgrades or other values to the grid.

A. Responses to Requests for Comment

Our comments address both the questions posed in advance of the March 1st workshop and the supplemental questions posted on the Commission’s DER workshops page on or around March 21st. We have chosen to address both sets of questions because both sets reflect important aspects for the development of a DER valuation framework. In this respect, we are aware that the Commission Staff’s addition of the supplemental questions states a preference for comment on

1 See CPUC D.17-09-026 at p. 46 and p. 49-50
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K747/196747754.PDF
technical value calculations. However, the topic of technical value calculations cannot be divorced from the process that is used to reach such conclusions – consideration of technical value calculations is best suited to a formal stakeholder proceeding where stakeholders have access to necessary data upon which to base any assumptions and calculations. Therefore, these comments should be viewed as a framework for future discussions and identification of selected current knowledge gaps, rather than end conclusions about precise valuation. The latter simply is not feasible at this time given the availability of relevant data. Additionally, these comments should be viewed as the beginning of a conversation about how the Value of DG tariff should be structured and which values should be considered and the JSP reserve our right to identify and quantify additional value streams in the future, both in this informal comment process and future docketed proceedings.

II. Workshop Agenda Questions

A. What’s the Illinois-specific context for distributed generation valuation and compensation that is the same as or different from other states?

Illinois’ Use of a Rebate is Unique but Manageable if Done Correctly

States have typically performed evaluations of DER value so as to arrive at a levelized long-term rate denominated in $/kWh, often for comparison to an applicable retail rate. Illinois law by contrast states:

[C]alculations for valuing distributed energy resource benefits to the grid based on best practices, and assessments of present and future technological capabilities of distributed energy resources. The value of such rebates shall reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs.2 [Emphasis added]

The statute both identifies a narrow set of values—“value of the distributed generation to the distribution system at the location where it is interconnected”—and also a far broader set of values “benefits to the grid.” These parallel (i.e. separate) requirements must both be analyzed.

The difference embodied by the statutory requirement that “value . . . to the distribution system” be reflected in a rebate does not necessarily require a wholly unique valuation methodology relative to those used elsewhere. In many ways, this uniquely sets up Illinois to capture the long-term approach proposed above with a rebate value that takes into account a 25-30 year horizon of benefits to the distribution system both at present and in the future.

We also observe that Illinois law establishes that smart inverter tariffs must provide for separate compensation for “additional uses” of the smart inverter. Thus, in order to be consistent with Illinois law, compensation includes:

2 220 ILCS 5/16-107.6(e)
• **An Up-Front Payment:** Section 16-107.6(g) makes clear that both before and after the Commission sets a value of solar calculation, the customer (or in some cases the developer) must be provided a rebate within 60 days of an application.

• **Ongoing Payments:** Section 16-107.6(b) establishes that “The tariff shall also provide for additional uses of the smart inverter that shall be separately compensated.” [Emphasis added] Because the “additional uses” include actions at the utility’s sole option that take place over time, the ongoing revenue streams cannot be accurately predicted at the time of the rebate.

**Most States Have Not Set Firm Timelines for Implementing Distribution Value Compensation**

The investigations of distribution value that have taken place in other states have a more fluid character than is present in Illinois. Investigations of distribution planning and the development and validation of distribution value methods are not generally tied to any specific timeline, or DER penetration threshold. For instance, California’s efforts towards developing granular locational benefits valuation methods commenced in August 2014.3 While California has adopted several decisions associated with the initiative, approving demonstration projects, initial versions of valuation and planning tools, a framework for distribution investment deferral using DERs, and a grid modernization framework, it continues to revise its methods and has not established any firm timeline for the broad deployment of locational value compensation for DERs.4 In its NEM 2.0 decision (D.16-01-044), the California PUC placed new net metering customers on Time-of-Use tariffs but did not otherwise change the compensation structure from full retail rate net metering because they recognized that many of the benefits of net metered systems had not yet been fully realized.

Likewise, efforts in other states, such as New Hampshire, Maryland, Rhode Island, and Connecticut, remain in the relatively early stages of investigating protocols for establishing distribution value and overall “transformation” of the distribution system, without any firm timelines for completion or deployment.5,6,7,8 Only one state, New York, has broadly deployed a DER framework reflecting a component for distribution value, and has done so only for community solar and large commercial customers on demand-based rate structures, and in an interim manner as the valuation methodology and tariff are more fully developed.9 Mass market customers, defined as residential and small commercial customers (not on demand-based rates), were kept on the traditional NEM structure. Even so, New York’s decision, compelled by a self-imposed timeline to take steps towards a value-based regime, recognized that much more data and

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4 See CPUC decisions in Docket No. R.14-08-013, D.17-02-007 (February 16, 2017), D. 17-09-026 (October 6, 2017), D.18-02-004 (February 15, 2018), and D.18-03-023 (March 26, 2018).
6 Maryland Public Service Commission. Public Conference 44 (PC 44). http://www.psc.state.md.us/search-results/?keyword=PC44&x.x=0&amp;x.y=0&amp;search=all&amp;search=rulemaking
8 Connecticut Public Utility Regulatory Authority. Docket No. 17-12-03. http://www.dpuce.state.ct.us/doccurr.nsf/(Web+Main+View/All+Dockets)?OpenView&StartKev=17-12-03
work was necessary to refine the methodology to reflect the full value of these resources.\textsuperscript{10} Furthermore, New York’s tariff is using an interim ‘Market Transition Credit’ for community solar projects to account for the fact that the distribution and other values are insufficiently developed at this time as well as to allow for a smooth transition towards a value-based regime.

Illinois law by contrast establishes a “threshold date” based on the current 5% of peak load net metering penetration cap that triggers a move to a locational distribution value framework.\textsuperscript{11,12} This potential “cliff” necessitates that Illinois proceed with both a sense of urgency in its own consideration of developing initial valuation methods in order to ensure that the system can be deployed by the time the 5% cap is hit – and an understanding that these methods will by their nature be incomplete.

The New York experience is instructive in this respect. Rather than assigning a zero distribution level value for DERs due to a lack of perfect data, it acknowledged that value does exist and adopted an interim system, including a ‘Market Transition Credit’ linked to the full retail rate. Illinois faces a similar choice in the future, and the Joint Solar Parties strongly recommend that it not let the perfect become the enemy of the good.

The Statute Requires That Values Beyond Distribution Value and Smart Inverter Services Be Included

As explained above, Section 16-107.6(b) and (e) do not simply refer to compensating DER for “distribution” value, but also value to “the grid.” While “the grid” is not defined, the plain language meaning is far broader than simply the distribution system. The language of Section 16-107.6(e) in particular supports this view, where “the grid” and “distribution system” were used in adjacent sentences, suggesting that the terms were meant to address different values. The Joint Solar Parties fully support both identifying distribution-specific values and other values to “the grid.”

Beyond the statutory language, there are several policy justifications for taking a broader view than simply the “distribution” value. Indeed, one reason why distributed energy resources are so cost effective is that they provide value that accrues at different levels of the electricity system. A solar PV system can help avoid a substation upgrade, but it also reduces energy demand and associated emissions. The substation that system helps avoid can’t avoid greenhouse gas emissions just as a peaker plant can’t relieve a local constraint on the distribution grid. DER advocates often refer to a comprehensive view of the DER value as considering the “full stack” of value.

The reasons for taking a broader view is multi-fold. First, the focus on distribution value renders any valuate incomplete unless other means of realizing system level values are present, such as the appropriate reflection of other value components in rates paid by customers and compensation paid to those customers for exports. Second, due to the higher degree of difficulty in developing

\textsuperscript{10} NYPSC Matter No. 17-01276 (Value of DER Working Group).  
\textsuperscript{11} 220 ILCS 5/16-107.6(a)  
\textsuperscript{12} The JSP note that during the March 1 workshop, several parties highlighted the differing approaches to the underlying methodology for calculating the NEM cap. Here, the JSP simply note the importance of this issue, the impact that it will have on how long the Commission has to come to a new tariff, and the need for resolution.
distribution level values, primarily due to insufficient data, some states have included distribution value only as a placeholder and not assigned it any specific value. For their purposes, this approach may be reasonable because those studies were designed as initial investigations, not for the specific purpose of establishing rates or compensation. As previously noted, Illinois’ efforts take place in a different context because the value is to be used to determine rebates. Third, to our knowledge no state has attempted to fully capture the value of smart inverter services in there studies; again, typically leaving smart inverter services as a placeholder subject to future refinement. This further points to the need for Illinois to take an evolutionary approach to the tariff.

As previously discussed, Illinois law requires rebates to be designed to reflect distribution value as one of multiple values, and that separate compensation be provided for other services. Thus there is a separation between compensation for:

- Values to the grid that can be developed in advance (either through specific and currently available data or through proxy values); and
- Ongoing services that depend on dispatch of the smart inverter to address unpredictable need for services (e.g., voltage support, frequency regulation). Given that smart inverter functions, including but not limited to the volt-watt and frequency-watt modes, control the output of a DER (i.e., reducing availability to a customer), it is critical that the functions not be activated for control by a utility until mechanisms to provide commensurate compensation are in place.

B. What approaches from other states may fit or not fit in Illinois and why?

As discussed in our response to Question (A), Illinois does not have the luxury of indefinite time to develop an approach to assigning locational distribution value. The impending net metering cap creates a need for prompt action to develop at least a first-generation model that can be deployed by the threshold date.

Given both the statutory requirement for 5% and Illinois’ longer term goals, the Joint Solar Parties recommend that the Commission follow a path that combines approaches from New York and California.

In the near term, we recommend the approach taken in New York whereby the Commission has taken an evolutionary approach to establishing location and time differentiated values, while fully acknowledging that while a step in the right direction, the valuation does not fully capture the benefits of DG. As a general approach to distribution value, the New York example is also instructive – it sets a system-wide distribution value and layers on top of that any location-specific benefits that can be identified.

In the longer term, we recommend the process employed in California through its Distribution Resource Planning proceeding as the most complete and comprehensive approach for several reasons. First, as in New York, California has recognized that its vision of transforming distribution planning and unlocking DER value is not a short-term initiative; it is a long-term evolution. Second, California’s approach encompasses a series of essential components towards this end, addressing not only locational DER value, but also utility business models, distribution planning, grid modernization, and more general DER integration. Third, the processes it has
employed, using open and transparent, formally-designated technical working groups with clearly defined objectives, timelines, and deliverables is consistent with developing the type of reliable, fact-based information needed to support regulatory determinations.\textsuperscript{13}

C. What can be gleaned from original FEJA language or other key policies about rebates and valuation objectives and perspectives?

Several guiding principles for establishing valuation protocols and rebates within Illinois policy, as follows:

**Long-Term Perspective for Valuation:** See Foundational Goals and Principles at page 4 above.

**Supporting Long-Term DER Growth:** See Foundational Goals and Principles at page 4 above. In addition, Section 1(a)(1) of the FEJA contains several references to the overarching objectives of the law, among them, “the State should encourage the adoption and deployment of cost-effective distributed energy resource technologies and devices…encourage private investment…stimulate economic growth.” This points to an intent to support sustained and consistent growth of DERs, as private investment and economic growth will not be achieved if the characteristics of the DER market are uncertain, unpredictable, or otherwise inconsistent. Long-term growth requires market stability, consistency, and predictability for providers and customers and retains a solid and predictable value proposition.

This objective is further supported by the design of the Adjustable Block program. Section 1-75(c)(1)(K) provides that the Adjustable Block program provide a stable platform in order to “enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time.” This likewise supports the premise that overall intent is to enable consistent long-term growth through the establishment of a predictable DER market.

Furthermore, see the importance of long-term DER growth to supporting Illinois’ NextGrid vision, as described in the section ‘Illinois Supports Expanding Distributed Generation’ starting at page 2 above.

**DER Value Must be All-Inclusive:** The DER “value stack” consists of numerous components at different levels of the system, each of which is contributor to the whole. While Illinois law focuses on value to “the grid,” including but not limited to the distribution system, in the context of rebates, assessing distribution system value should not subsume or push aside other grid values that do exist.

Inasmuch as a smart inverter is inextricably linked to the associated generation asset, the asset should be viewed holistically as a system. We believe that Section 16-107.6(b) and (e) require the Commission to consider a broader system perspective with respect to other beneficial uses to the extent that they are not adequately addressable through other means. Ultimately, the proper value of PV solar DERs must be analyzed from a holistic perspective and Commission should use every

\textsuperscript{13} See for example, the materials associated with several defined working groups that support the Distribution Resource Planning process. https://drpwg.org/
means at its disposal to ensure that all benefits are properly considered and valued. Not doing so undermines the overarching intent of the FEJA to support cost-effective DER deployment.

D. What is the relationship to the valuations required by the Adjustable Block Program found in Sections 1-75(c)(1)(K) and (L) of the IPA Act?

The Adjustable Block Program is effectively a forward purchase of renewable energy credits ("RECs") at a price set at the time of purchase with a price signal related to demand. While the details of the Adjustable Block pricing model are substantially different than the value of DG calculations, the essential feature that both are intended to provide a known revenue stream based on a signal provided (and locked in) at the time of application.

That said, the Adjustable Block program is essentially monetization of one revenue stream, the REC. Put another way, the incentive provided by the program represents only RPS compliance value to the exclusion of other values. As previously described, the Adjustable Block Program endeavors support the scale up of solar photovoltaics, through the use of predictable and transparent pricing. The basic structure of the Adjustable Block pricing model illustrates this effort. The Adjustable Block Program, however, was not created within a conversation of how to fully value the environmental and societal benefits DERs bring to the grid. This limitation may need to be addressed in the DER valuation proceeding.

From the perspective of long-term predictability, while the concepts may be similar a distinction must be made between what is addressed in the Adjustable Block Program relative to what is required for distribution value determinations and rebates. The Adjustable Block program, as an instrument of the RPS requires that REC contracts have a term of at least 15 years.14 As a definition of “long-term”, 15 years must be viewed in the context of the RPS which does not contain incremental additional requirements beyond 2025. Moreover, RECs are instruments for which the value is driven by numerous factors, in particular changing policy.

While the Adjustable Block Program is a reflection of policy, it should not be taken to confine the meaning of “long-term” to 15 years when considering the long-term value of DERs to the distribution system. Fifteen years was hard-coded into Sections 1-75(c)(1)(K) and (L) of the IPA Act, but a statutory time horizon is conspicuously absent in Section 16-107.6(b) and (e) of the Public Utilities Act. Furthermore, the Joint Solar Parties note that in creating the Adjustable Block pricing model, where the IPA attempted to model the non-REC costs and revenues of PV solar DERs, the IPA assumed a useful life of 25 years for energy and other revenues. As DERs contribute distribution value throughout their respective lifetimes, the assessment of that value should not be artificially confined to a shorter period. A 25-30 year time horizon is a more reasonable time frame for which to assess distribution value.

E. What categories of data are or are not available that will influence value calculations?

Generally speaking, utilities in Illinois currently use embedded cost of service studies (“ECOSS”) rather than MCROSSs in ratemaking proceedings. (See, e.g. ICC Docket No. 01-0423, Interim Order dated April 1, 2002 at 124.) The lack of reliable marginal cost data is a clear data gap at present:

14 20 ILCS 3855/1-75(c)(1)(L)
marginal costs, whether system-wide or localized, are the widely accepted means for calculating the value of avoided or deferred investments. It is not entirely clear whether existing data sources could serve as a temporary substitute for marginal cost data. Ameren, ComEd, and MidAmerican do not currently submit long-term distribution planning information to outside entities for evaluation, so we do not know precisely what information they possess that could be useful. The long-term valuation of distribution assets underlying the formula rate approach used by Ameren and Commonwealth Edison may provide some insights. However, we emphasize that determining the usefulness of this data requires a much more thorough review, analysis and overall vetting. Also, while the utility collects SCADA data regarding reliability, there may be reasons to look at more granular information to determine projected reliability benefits. Furthermore, these data sources are typically based on a short-run horizon rather than the long-run horizon needed for properly valuing distributed generation resources.

Apart from that, it is impossible to know what other gaps exist at this early stage of the investigation. Data needs and availability, now and in the future, have been the subject of months and years of working group meetings among industry experts. This type of process is essential, insofar as it is not only a question of identifying what data is necessary, the process must encompass the development of solutions that fit available data, methods of obtaining data that is not presently available, and how ongoing improvements in distribution architecture as well as regulatory refinements via NextGrid will support the assembly of additional data for future refinements. The availability of data and future refinements is exactly why taking an evolution approach to DER valuation is recommended.

F. What are process suggestions or considerations for arriving at DG rebates?

We recommend that the Commission consider the following hierarchy of issues for translating the statutory language into a practical tariff:

- **Consistency with Illinois Law:** The approach must be consistent with Illinois law. This requires both an up-front rebate and an ongoing payment for services.
- **Sustainable, Long-Term Market Development:** Within the confines of Illinois law, the Commission should use its discretion where available to provide reliable, long-term price signals for developers of different types of DERs. Those signals should be created, so the interests of the developers—and their customer(s)—align with the utility’s distribution planning needs.
- **Implementable on Statutory Timeline:** While long-term viability is critically important, it is also important not to harm the market in crucial early years by having a failed or delayed signal. The Commission should make explicit to all parties that while market development is a primary policy concern, and it will take steps to ensure that approved formula pursuant to Section 16-107.6(e) is memorialized in utility tariff before the 5% cap is hit so it can become effective immediately upon the cap being triggered.

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• **Evolution:** While it is important for the early days of the program to be implemented and implementable when the 5% cap is triggered for each utility, the Commission should treat these tariffs as constantly evolving (for new systems) as utility distribution grids (and related services), distribution grid planning, utility business models, and distributed energy technologies evolve. This approach should also take into consideration differing abilities of end-users or customers of DERs to respond to these tariffs as well as how that ability may evolve over time as technology and markets evolve. This should apply to both to up-front payments as well as the “separately compensated” periodic payments.

With respect to the specific process, our overarching recommendation is that developing methods of determining compensation and rebate amounts proceed largely through working groups consisting of stakeholder experts, utility personnel, and a facilitator (e.g., Commission staff or an outside, independent group working on behalf of the Commission). This working group or groups must have a formal mandate and clearly defined objectives and timelines.

At a high level, our expectation is that the working group(s) would produce reports on a set timeline consisting of proposals for different aspects of the valuation regime that can be distributed for broader stakeholder comment. The national lab deliverable discussed at the March 1 workshop could be the starting point of discussion for these working group(s). The reports themselves would discuss the reasoning behind the proposal, potential alternatives, and level of stakeholder consensus on different aspects to the extent that some elements cannot be agreed upon. After comments are received, the Commission would, through a formal proceeding, make its decision on what, if any, aspects to adopt, and provide direction for any future work it believes is required.

Given the degree of urgency establishing a clear path to the development of at least a first-generation valuation methodology, we recommend that working groups be convened as soon as possible, with the docketed proceeding potentially starting before the 3% threshold is met. To ensure the process stays on track, interim milestones should be set with periodic progress updates given to the Commission. Among the highest priority topics that must be addressed are:

• Assigning the relative level of priority given to developing values to the suite of grid and distribution grid benefits that can be provided by DERs.
• Generating a common understanding of currently available data.
• Producing a work plan that is can result in the adoption of at least an interim rebate determination methodology within 18 months.
• Producing a contingency work plan designed for implementation in no greater than 6 months for use in the event it becomes necessary due to the approach of the net metering cap.

**G. Which value elements are most important for Illinois?**

This is a critical question that is not possible to fully answer at this time. Distribution deferral value and marginal reliability value are likely to be a large component of distribution service value. Upgrades to the distribution system as part of the interconnection process and their impact on deferred/avoided upgrades are another. We recommend that developing a value prioritization list reflective of both relatively magnitude and data availability be among the first tasks undertaken by technical working groups.
H. What elements should be considered in differentiating DG value by location?

Generally, we think that the technical aspects of this question are most suitable for detailed consideration in a working group format. However, there are a series of general principles that should be considered in the context of implementation, as follows:

- **Transparency**: Information on locational differentiation must be made available in a manner that is easily accessible, and can be processed by providers and customers. For instance, if a given value is specific to an area served by a specific substation, it must be possible to reliably identify customers served by that substation through using information available to both providers and customers. Furthermore, if a local area is targeted for a certain amount of DERs to meet a need, the status of enrollment must be updated in as close as real time as possible.

- **Simplicity**: Granularity must be balanced with a need to make the system manageable for providers and customers. In practice, this means that granularity should not be established to a resolution not supported by available tools, and differentiation should likely target a relatively small number of particularly high value locations.

- **Consistency**: The duration of location specific values (e.g., the time between updates) must be long enough to allow providers to adapt to target those areas.

- **Predictability**: Location-specific values must be fixed over the long-term for customers that enroll at a given value, in recognition that customers require this predictability and that as long-lived assets, DERs are providing long-term value consistent with identified current and future needs.

III. DG Valuation Questions

On or around March 21st a series of additional questions addressing technical DER valuation were posted on the Commission’s DER Valuation website. At the outset we wish to state that these questions are an excellent starting point for establishing what needs to be answered as part of this process. While we appreciate the opportunity to respond and the ambition of promptly seeking answers to these questions, we are concerned that the timeline is too short for stakeholders to formulate complete responses, and in some cases it is not entirely clear to us what information is actually being requested. Our brief responses below should be considered preliminary, as we believe there are numerous nuances that require more work to adequately sort through.

Towards this end, we recommend that the work of California’s Locational Net Benefits Analysis (“LNBA”) working group be consulted. The LNBA working group has issued two reports to date on locational benefits analysis. The first report formed the basis for the CPUC’s adoption of the initial parameters and capabilities of the LNBA tool. The second report addresses refinements to the tool to add greater granularity to locational values for system-level benefits, locational transmission benefits, and distribution benefits. The reports themselves and related materials, which address consensus and non-consensus recommendations and stakeholder viewpoints, can

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16 CPUC D.17-09-026. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K747/196747754.PDF
provide a solid foundation for Illinois to work from.\textsuperscript{17} Beyond the valuation methodologies, they illustrate how certain aspects of the analysis were prioritized, the functionality of a tool showing LNBA results, the evolution of the analysis, and the process employed.

Process-wise, we have recommended that a working group format is the most effective way to develop information and valuation proposals. Additionally, we recommend that stakeholders be given an opportunity to submit reply comments to any comments received in response to the present set of questions, with at least a three week response window from the time the permission to reply is granted.

\textbf{A. Should the calculated values be limited to the value of distributed energy systems to the distribution network? If not, what other identifiable benefits of distributed energy systems should be included in the values calculated pursuant to Section 16-107.6?}

As discussed more fully in the section ‘Illinois’ Use of a Rebate is Unique But Manageable if Done Correctly’ at page 6 above, Illinois statute requires that the DG rebate include both benefits ‘to the grid’ and benefits to the ‘distribution grid’.

In order to support the state’s goals and meet its statutory requirements, it is critical to consider DER value at all levels of the system. This value may be reflected in compensation for DERs in different ways. For instance, one source of revenue is through net metering credits. However, this only captures a limited universe of value streams.

It is critical that the full capabilities of a DER system be fully reflected in the associated compensation it receives, whether through the DG tariff or another mechanism. Traditionally recognized value categories include:

1. Avoided capital costs for distribution and transmission upgrades
2. Avoided distribution operations and maintenance expenses
3. Avoided energy
4. Avoided generation capacity
5. Avoided ancillary services
6. Avoided transmission and distribution system losses
7. Avoided RPS integration costs
8. Avoided environmental impacts, including but not limited to emissions of greenhouse gases and criteria air pollutants.

\textbf{B. What are the types of values that distributed energy systems provide to the distribution network?}

The general categories of values that DERs can provide to the distribution system are typically categorized as:

\textsuperscript{17} The full working group reports and materials are available at: \url{https://drpwg.org/sample-page/drp/}
• Avoided distribution capacity costs
• Distribution voltage/power quality support
• Reliability (non-capacity related) and resiliency

In addition to these broad categories, participants in California’s LNBA working group have identified additional potential values including:

• Reduced distribution maintenance
• Extended equipment lifetimes
• Enablement of reduced sizing in equipment replacements
• Enhanced situational awareness & grid visibility

As discussed in previous sections, benefits to the distribution system are not the only benefits to be incorporated into this tariff.

C. How does each type of value that a distributed energy systems provide to the distribution network (identified in part (b)) vary geographically?

As a general matter, all of the categories likely display some level of geographic variation. We do not possess the information to describe how exactly each value varies geographically on the systems of Illinois’ electric utilities, such as to what degree a given value may vary on individual circuits or at specific locations on a circuit. However, with respect to geographic variations we make two initial observations:

• Variability can be a matter of perspective and scale, insofar as small variations may exist down to a highly local level while by and large, the values remain similar within a much larger area.
• The fact that variability exists on the local level does not dictate that the use of system-wide estimates is inappropriate, in particular where a lack of granular data prevents more precise estimates from being made.
• Long-time horizons mean that even if there are not near-term identified locational needs, a project is likely to avoid investments over its life and that value may best be captured through a system wide average rather than an extrapolation of a locationally-specific value.

Defining parameters for evaluating local variability, including data needs, availability, and appropriate scales, should be discussed in the working group process we recommend.

D. How does each type of value that a distributed energy systems provide to the distribution network (identified in part (b)) vary across time?

It is not clear to us whether this question is intended to refer to variability from the perspective of: (1) how needs may arise consistently during specific periods (e.g., high loads during peak periods) or, (2) the time horizon associated with how needs are identified via planning processes. Both perspectives are important for determining how values are identified. The first is largely a question of the capabilities of a given generating facility to respond in a manner that reflects the temporal need for a given service (e.g., storage dispatch, control of a smart inverter).
The second is more fundamental with respect to determining long-term value. With respect to this type of variability, once a need is identified and planned for (e.g., targeted for investment), it ceases to be “variable” because decisions of how to meet that need must be made. Those decisions, whether they involve investments in traditional infrastructure or DERs, fix the value of an asset based on the available information at the time they are made. Therefore, that value exists for the duration of the life of the asset as it provides the associated service.

Unplanned needs also exist, either because they arise as a result of changing conditions in the short-term (e.g., unexpected load growth), or because they exist beyond the time horizon of typical planning. Either situation presents the potential for DERs to generate value, but that value may be difficult to identify. This issue merits further discussion in the working group process we recommend.

E. How does each type of value that a distributed energy systems provide to the distribution network (identified in part (b)) depend upon the distributed energy system technology?

At a basic level, a DER may be dispatchable or non-dispatchable. A dispatchable DER includes one equipped with energy storage, or to a lesser degree, one controlled by a smart inverter. Dispatchable DERs offer greater value at all levels because they can respond to specific conditions, but that does not mean that non-dispatchable DERs are not capable of providing value. A non-dispatchable DER can provide value when its characteristics of operation align with system needs. For instance, a distribution feeder that has consistent day-time peaks benefits from DERs such as solar that reduce load during those typical peak periods.

Energy storage enhances a DER both from the perspective of dispatchability and range of operation. The value of an energy storage DER may vary based on its maximum output and storage capacity. Smart inverters enhance the capabilities of a DER in a more limited way because they can only modify the output within the range that the DER would normally operate, though communication capabilities can also contribute to increased grid visibility irrespective of whether the output of a DER is modified. We recommend that the Commission review the previously referenced Californian LNBA working group materials and the California Smart Inverter Working Group (SIWG) reports on smart inverter functions for a more detailed assessment of smart inverter capabilities.
From the perspective of specific needs identified in the distribution planning process, the ultimate benchmark is the specific cost of a project. However, we lack visibility into the assumptions underlying identified needs, as well as the nature, magnitude, and timing of those needs. A more transparent distribution planning process, with opportunities for non-utility stakeholders to view and understand planning procedures, is necessary.

G. How can each type of value that a distributed energy system provides to the grid (i.e., the systems actual performance) be evaluated?

At a high level the measurement of DER performance is a function of output or response as aligned with a need. While the simple answer to this question is that appropriate metering should be employed, it is difficult to specify what type of measurement is necessary (e.g., interval, communication) without first defining the nature of a grid service or need. As a general rule, the level of granularity of performance measurement should be balanced against the cost of achieving that level of granularity in the context of an individual grid service. Also, as discussed previously in our comments, the Commission should take an evolutionary approach to these tariffs and valuation approaches while also incorporating policy goals such as market development and financability of DER projects.

H. If you identified the value of distributed energy systems benefits other than benefits to the distribution network, please address questions (b) - (g) with respect to such other identifiable benefits.

Due to the short time frame for submitting these comments we have not been able to assemble a response to this question other than to highlight that Illinois law requires that this tariff address benefits not only to the distribution system but also to the grid more generally. We strongly recommend that any recommendations made on this topic not be made until stakeholders have had additional opportunities to address it via written comments and working group proceedings.

I. Considering available information, how should distributed generation energy resource benefits be calculated?

In our estimation, at this time available information is minimal. The first step in moving this initiative forward should be the establishment of guiding principles and a well-defined process for developing the necessary information and ultimately a methodology proposal in a transparent manner. In light of this we make the following high-level recommendations:

- Benefits should be calculated using a time horizon consistent with the useful life of DERs.
- The scope of benefits calculations should consider the full suite of DER benefits in order to develop a complete picture and allow the evaluation of whether DER customers are being compensated accordingly through different mechanisms.
- The methodology should be arrived at and vetted through a transparent working group process, with any proposals subject to stakeholder comment before adoption.
- The determination of values should employ a phased approach that allows first-generation methods to be developed in the near term, while allowing for refinement of those methods over time.
IV. Appendices

For the information of Commission Staff, PNNL, and other stakeholders, we have attached the following documents for reference:

SEIA’s 5-Part Grid Modernization Whitepaper Series:

Part 1: How California & New York are Building Grids that Encourage the Growth of Distributed Energy Resources

Part 2: Improving Distribution System Planning to Incorporate Distributed Energy Resources

Part 3: Hosting Capacity: Using Increased Transparency of Grid Constraints to Accelerate Interconnection Processes

Part 4: Getting More Granular: How Value of Location and Time May Change Compensation for Distributed Energy Resources

Part 5 (Forthcoming): Distributed Energy Resources as Distribution Grid Infrastructure: Opportunities Beyond Wire


We appreciate the opportunity to provide comments in this informal stakeholder proceeding and look forward to continuing to work with the Commission Staff and other stakeholders to develop a Value of DG tariff that works for all of Illinois’ goals in both the short term and the long term.

Sincerely,

Sean Gallagher  Lesley McCain  Brandon Smithwood
VP, State Affairs  Executive Director  Policy Director
Association  Association  Solar Access

Solar Access Association

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SUSTAINING SOLAR BEYOND NET METERING

How Customer Owned Solar Compensation Can Evolve in Support of Decarbonizing California

Views expressed herein are that of the author and are not endorsed by contributing organizations.

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INTRODUCTION

California has committed to rapid decarbonization of its power sector. The state is pursuing that objective through a wide range of policy solutions, one of which is net metering, an incentive encouraging customer adoption of renewable distributed generation, especially solar. To date net metering has supported the adoption of solar by over 725,000 California customers, totaling nearly 6 GW of installed capacity. These adoptions have contributed to reductions in greenhouse gas emissions from the power sector and local job creation. Net metering has been a success by many of California’s key measures.

Looking forward, California’s path to decarbonization assumes increased reliance on renewable energy, including estimates of up to 16 GW of behind the meter solar by 2030. Achieving these targets would require accelerated customer adoption of solar. But as analyses of California’s electric system have demonstrated, continued growth in generation during day-time solar peak periods creates two challenges: excess generation at the system-level and grid constraints at the distribution-level. Excess generation at the system-level has been demonstrated by increasing negative prices and resource curtailment, including of renewable generation. Distribution-level grid impacts have been demonstrated through analysis of distribution system hosting capacity showing limited capacity to absorb mid-day solar production in areas of high-solar penetration.

At their core, these challenges are the manifestations of

1 Use of the term “solar” throughout this paper implies behind the meter, customer owned solar generation.
misaligned power supply and demand. Going forward, rather than spread like seeds in the wind, solar energy needs to be planted at locations advantageous to the grid and needs to produce simultaneous with demand, or stored until there is demand. Solar alone will not suffice; it needs to be locationally targeted and co-located with storage. 6

Meanwhile, California policy-makers have continued to push for differentiation of incentives for solar by location, ensuring grid costs are fairly recovered, and enabling customer choice. A clear need for balancing these objectives with the State’s decarbonization imperative exists.

This paper reexamines net metering, asking how to build on its success to further California’s decarbonization, account for location value, fairly recover grid costs, and enable customer choice. Evaluating alternative policies and applying consistent criteria reflective of California’s principles this analysis identifies advantages and disadvantages to net metering and variations thereof. Based on this analysis we conclude California can sustain solar beyond net metering. We recommend California policy-makers move expeditiously to transition the state’s solar compensation framework toward a net billing structure with locationally differentiated prices paid for exports. As detailed further in this paper, the transition may be eased in several ways and informed by data and insight gained through evaluation of current net metering policies, helping to sustain growth in customer adoption and achieve forecasted levels of solar.

DEFINING NET METERING AND VARIATIONS

KEY CONCEPTS UNDERPINNING NET METERING

The following section advances a standardized taxonomy and framework for net metering and its variations.

California Public Utilities Commission (CPUC) Decision (D.) 16-01-044 provides the following explanation of how net metering (NEM) works in California:

“Under NEM, customer-generators offset their charges for any consumption of electricity provided directly by their renewable energy facilities and receive a financial credit for power generated by their on-site systems that is fed back into the power grid for use by other utility customers over the course of a billing cycle. The credits are valued at the “same price per kilowatt hour” (kWh) that customers would otherwise be charged for electricity consumed. Net credits created in one billing period carry forward to offset customer-generators’ subsequent electricity bills. At the end of every year that a customer-generator has been on the NEM tariff, the credits and charges accrued over the previous 12-month billing period are “trued-up.” A customer producing power in excess of its on-site load over the 12-month period may be eligible for “net surplus compensation” under certain conditions. 7

Within this explanation are both physical (e.g., consumption) and financial (e.g., credit) concepts.

FIGURE 1
ILLUSTRATING PHYSICAL NET METERING CONCEPTS

Figure 1 illustrates the physical net metering concepts, consumption and production of a customer generator over a single day. During different times of the day, production and consumption may or may not overlap, delineating the concepts of consumption from the grid, exports to the grid when on-site production exceeds consumption, and self-supplied consumption (self-supply). Self-supply, as illustrated here by the figure’s yellow area, manifests as reduced consumption from the grid. These dynamics are manifest in the values recorded by the customer’s meter, with values rising when consumption from the grid increases, flat when production and consumption are equal, and falling when exports increase.

7 D.16-01-044, Page 13. CPUC.
Net metering overlays certain financial concepts on these physical ones to compensate customer generation. Most prominent is the concept of netting, as illustrated in Figure 2. Netting is offsetting a financial charge for consumption with a financial credit for production. As illustrated above, that offset can be physical and simultaneous as with self-supply (yellow area). Alternatively, netting can be non-simultaneous whereby credits for exports (maroon area) are carried forward to offset subsequent charges which would otherwise result from consumption from the grid (blue area). Key to understanding net metering is this delinking of the physical and financial: netting enables a customer to financially self-supply while consuming from the grid — while the meter read increases, the consumption charge does not.

Netting can be allowed at different intervals ranging from instantaneous to annual. Accounting for netting relies on reading a meter, so in practice the most granular netting interval for determining simultaneous self-supply is the most granular meter interval — how often the meter records a customer’s consumption. In California, this is currently hourly for residential customers and 15-minute for commercial. The netting interval may have a substantial impact on the value of a solar investment for the adopting customer. Traditionally longer netting intervals are more advantageous for the adopting customer as seasonal variation in production and consumption allow for maximum netting. Customers with shorter netting intervals, such as commercial customers, receive less benefit from netting.

**CORE STRUCTURES | NET METERING, NET BILLING AND BUY ALL, SELL ALL**

This analysis refers to alternatives to net metering as different core structures. The critical difference between core structures is what portion of production may offset charges for consumption, effectively compensating the customer for production at the rate she would otherwise be charged for consumption.

As summarized, a net metering compensation structure allows charges for consumption to be offset enabling compensation of all production at the consumption charge (netting). Two alternatives to net metering alter this approach to netting. The first alternative core structure is **net billing**, which awards credit to exports at a specified price which is different than the consumption charge. A net billing construct preserves self-supply, compensating the customer for the self-supplied portion of her production at the consumption charge. Credits awarded to exports are at a price other than the grid consumption charge, which may count against subsequent charges or be monetized. The second alternative core structure is buy all, sell all (BASA), which relies on a dual-meter system to meter all production and all consumption separately. All production receives compensation at a price other than the consumption charge. Under a BASA framework, self-supply does not offset the customer’s charges for consumption.

This formulation of core structures creates an important distinction between a compensation structure and the underlying rate design. In practice the two are intertwined, but the focus of this evaluation is how the overlaying compensation structure may be adapted. The limited exceptions to this approach are noted below.

Compensation of customer generation may be accomplished through adapting one of these three concepts to meet the goals of the jurisdiction. The following section describes the most accessible adaptations that can be made, constituting a tool kit available to policy makers.

**THE TOOL KIT | CONSUMPTION CHARGES, EXPORT PRICES, ANCHORS AND ADDERS**

Consumption charges, export prices, anchors and adders are tools that can be used to adapt one of the core structures to accomplish objectives.

The “consumption charge” is a charge to a customer for power consumed within a designated period. These charges in California today are largely volumetric for residential and small commercial customers. Furthermore, residential charges are tiered, such that the charges for consumption increase as consumption increases. A primary tool available to the policy maker is amending the consumption charge required of a customer generator. For example, in D.16-01-044 the CPUC required new customer generators to enroll in time of use (TOU) rates and pay certain non-bypassable charges on power exported to the grid in each metered interval (see dark blue section of Figure 1).

“Export prices,” as used in this paper, is a term deliberately distinct from retail rate or consumption charges that instead refers to the compensation level paid to the customer for exports. BASA treats all production as an export. Net billing pays a price to exports (only), while compensating self-supply at the consumption charge. Under these constructs policy makers can adapt export prices to suit objectives. Export prices could be based on many factors, including where the resource is located, when the resource is delivering energy to the grid, and the market conditions that exist when the export occurs.

Beyond consumption charges and export prices, anchors and adders can be applied to achieve different objectives. The term “anchor” as used in this paper refers to a change to the customer compensation framework which reduces the customer’s economic return to align their interest with other objectives, such as encouraging generation at times and locations of greatest value to the grid. An “adder” is the opposite, contributing to the customer’s economic return in pursuit of additional advantage.

Anchors may include a fixed charge, minimum bill, standby rate, tolling fee for distribution of exported energy, demand...
charge, interconnection charge, prohibition on exports, or shorter netting intervals. Adders may include grid service payments, locational adders, environmental value, renewable energy credits, market transition credits, time of delivery adders, peak event-based adders or longer netting intervals. Complete definitions and references supporting these anchors and adders are provided in Appendix A.

In sum, policymakers have a wide range of options between three underlying core structures, and the application of customer charges, export prices, anchors and adders. Appendix B illustrates how certain states and California stakeholders have applied these tools. Looking forward to California’s future, the following section identifies a range of plausible options for consideration.

**POTENTIAL COMPENSATION STRUCTURES FOR CALIFORNIA**

In D.16-01-044 the CPUC asked staff and stakeholders to "explore compensation structures for customer-sited DG other than NEM, including analysis and design of potential optional or pilot tariffs, with a view to considering at least an export compensation rate that takes into account locational and time-differentiated values of customer-sited DG." In the spirit of this call to action, the following potential compensation structures for California were identified through stakeholder engagement and research on how other states are compensating customer generation. These options do not represent an exhaustive list of possible compensation frameworks, rather a reasonable cross-section reflecting ongoing trends in California’s energy policy landscape. This section introduces those options; a later section evaluates them.

Several new concepts are included within these options. They are introduced in the context of the following explanations of each option.

### TABLE 1

<table>
<thead>
<tr>
<th>OPTION NAME</th>
<th>SELF-SUPPLY</th>
<th>EXPORT PRICE</th>
<th>ADDER/ANCHOR</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 NEM 2.0</td>
<td>Y</td>
<td>Retail Rate</td>
<td>Selected Non-bypassable charges; Time of Use Rate</td>
</tr>
<tr>
<td>2 Net Billing</td>
<td>Y</td>
<td>Locational Value</td>
<td>Transferable Credit; Transition Credit; Opt-in Grid Services</td>
</tr>
<tr>
<td>3 Net Billing + Grid Services</td>
<td>Y</td>
<td>Market Price</td>
<td>Transferable Credit; Managed Demand Charge</td>
</tr>
<tr>
<td>4 Buy All, Sell All</td>
<td>N</td>
<td>Locational Value</td>
<td>Transferable Credit; Transition Credit</td>
</tr>
<tr>
<td>5 BASA + Grid Services</td>
<td>N</td>
<td>Market Price</td>
<td>Transferable Credit</td>
</tr>
</tbody>
</table>

10 To allow for comparison, the following assumptions are held constant throughout these options: current CPUC policy on minimum bill charges, non-bypassable charges, TOU rates, netting and true up intervals remain unchanged unless explicitly noted; no unidentified anchors or adders incremental to those identified here are applied.

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*Appendix A and B are posted at [www.gridworks.org](http://www.gridworks.org)*

*D.16-01-044, p. 103, CPUC.*
OPTION 1 | NEM 2.0
This option reflects the status quo. The only exception to current practice we contemplate is the possibility of further evolution of TOU rates to allow those rates to more specifically reflect grid conditions, including a) greater peak-to-off-peak rate differentials, b) greater locational rate specificity, and c) further shifts in TOU periods on daily or seasonal basis.

OPTION 2 | NET BILLING
This option reflects a net billing core structure with exports compensated at the resource's Locational Value, an export price informed by the Locational Net Benefits Analysis (LNBA).11 The LNBA is a methodology being developed under the supervision of the CPUC which differentiates the value of customer generation by location, as illustrated in Figure 3.

Depending on how the administratively set locational values are determined, this export price could differ between customers. To enable a predictable return for the investing customer, it is assumed that the export price paid to an enrolling customer would be fixed for a practical duration and variable following that duration, updated periodically, based on refreshed LNBA. It is assumed the valuation is updated annually to allow newly enrolling customers to be compensated at refreshed pricing.

Two additional features of this option may be considered to support customer adoption. First, would be the inclusion of a Market Transition Credit.

MARKET TRANSITION CREDIT | Awarding additional temporary compensation to a customer generator during a defined period (e.g., 5 years, indexed to total customer adoption, up to percent of system peak) that ramps down over time but recognizes the importance of continued clean energy development.

There are many ways such a credit could be structured. Here we envision a “step-down” Market Transition Credit, whereby an adder to the LNBA-based export price tapers down to zero over time. The scale and pace of the step-down could be benchmarked to installed capacity, like early California Solar Initiative rebate designs.

TRANSFERRABLE CREDIT | Allowing credit earned by a customer generator for exports to the grid to be transferred to any other customer at the discretion of the customer generator.

Because the net billing framework suggested here compensates exports at a price reflecting their Locational Value, credits earned for these exports could be transferred to any other customer. The impact of transferrable credits would depend on whether the generator must be “sized-to-load,” as is the case under NEM 2.0. We envision that requirement being lifted.

Finally, we contemplate the exports may also be eligible for participation in grid services on an opt-in basis.

GRID SERVICES | Market-based compensation for DER providing energy, capacity, voltage support, frequency regulation and resiliency pursuant to an identified grid need. Compensation may be at wholesale or distribution level.12

Compensation to customers opting into grid services would be an alternative to administratively determined export prices, such that the customer chooses one or the other, but is not eligible for both.

OPTION 3 | NET BILLING + GRID SERVICES
This option reflects a net billing core structure with exports compensated at market prices based on their participation in grid services markets. Whereas in Option 2 the customer would be defaulted onto the administratively determined LNBA-informed export price with the option to opt-in to grid services markets, Option 3 would default the customer’s exports into grid services markets. It is assumed that aggregators will serve as the customer’s agent in participating in such markets, but individual customer participation is not precluded.

MARKET PRICE | Prices paid for grid services may be market-based resulting from competitive solicitations, participation in organized wholesale markets or other transaction platforms. Distinct from other contemplated pricing mechanisms which result from administrative value determinations (e.g., locational value, retail rate).

An additional feature of this option would be a managed demand charge.

12 Wholesale Grid Services may include: energy, regulation up, regulation down, spinning reserve, and non-spinning reserve. Detailed service definitions at http://www.caiso.com/participate/Pages/MarkeetProducts/Default.aspx. In addition DER aggregations may be eligible to provide system, local or flexible resource adequacy capacity (RA). Designation of a DER/DERA for RA entails must-offer obligations (MOO) under the ISO tariff to participate in the markets for these wholesale grid services. Distribution Grid Services may include: energy (up/down), capacity (up/down), and voltage/volt ampere reactive (VAR, up/down). Distribution service definitions are detailed in CPUC D. 16-12-036.
This feature is highlighted because it may provide a meaningful opportunity for a utility to recover costs for grid services unless the need for those services is reduced by a customer's change in consumption or adoption of a storage technology. Volumetric charges may be reduced for customers receiving a demand charge.

**OPTION 4 | BUY ALL, SELL ALL**

This option reflects a buy all, sell all core structure with all production compensated at its Locational Value. An additional feature of this Option would be the inclusion of a Market Transition Credit.

As summarized, customer consumption is metered separately from production, enabling customer participation in other programs such as demand response to be evaluated and rewarded distinctly.

**OPTION 5 | BUY ALL, SELL ALL + GRID SERVICES**

This option reflects a buy all, sell all core structure with all production compensated at market based export prices based on their participation in grid services markets. Whereas in Option 4 the customer would be defaulted onto the administratively determined Locational Value export price, Option 5 would default the customer’s production into grid services markets. It is assumed that aggregators will serve as the customer’s agent in participating in such markets, but individual customer participation is not precluded.

In the next section, we turn to criteria which may be used to gauge the relative strengths of these options and an evaluation of their merits.

### EVALUATING IDENTIFIED OPTIONS

Returning to the identified opportunity: net metering has proven potential to incentivize customer adoption of solar. But does net metering support the alignment of supply and demand and thereby help solve key challenges facing California? Can those challenges be addressed while increasing affordability for all customers and preserving customer choice?

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**PRINCIPLES**

To evaluate the identified compensation structure options, criteria consistent with California’s principles must be identified. This evaluation begins with the stated principles of the CPUC in its DER Action Plan and supplements them based on stakeholder input, resulting in the following foundational principles:

### Adapted from the CPUC’s DER Action Plan

- DER able and incentivized to serve grid needs (Vision Element 2.A)
- Technologically neutral, competitive sourcing (Vision Element 2.C)
- DER valued fully, accurately, and impartially (Vision Element 2.D)
- Sourcing reflects locational value (Action Element 2.3)

### Incremental to DER Action Plan

- Grid valued fully, accurately, and impartially; recognized as essential
- Customer choice enabled, practical and informed
- DER should contribute to GHG reductions
- Valuation and incentives determined transparently
- Grid and energy services unbundled
- New technology leveraged to serve customers
- Grid peak-driven infrastructure investment minimized
- Increase affordability of service for all customers
- Ratepayer indifference
- California’s solar market grows sustainably

These principles represent a broad range of values and priorities held by policy makers, utilities, market participants, consumer advocates, and environmental interests.

### CRITERIA

To operationalize these principles and enable a practical evaluation of the options, the following criteria were derived: Locational Value, Grid Cost Recovery, Customer Choice and Decarbonization. These criteria have been defined as follows for the purposes of this evaluation.

**Locational Value**

This criterion asks whether the option compensates a customer generator for the locational value of its production as informed by the LNBA. Underpinning this criterion is the CPUC’s 2017 endorsement of the LNBA, which states, “the presumption is that the next regime of NEM incentives would be tailored to the relative costs and benefits of DER...”
Principles embedded in this criterion include: DER valued fully, accurately, and impartially; Sourcing reflects locational value; Valuation and incentives determined transparently; Increase affordability of service to all customers; Peak-driven infrastructure investment minimized

**Grid Cost Recovery**

This criterion asks how well the option recovers utility grid costs consistent with cost-causation principles and cost allocation. Because no new fixed or grid charges are assumed for the options under consideration in this evaluation the practical impact of this criterion is to advantage options which limit netting. Underpinning this criterion is the CPUC’s conclusion from D.16-01-044, “the principal potential disadvantage of continuing the current full retail rate NEM tariff is economic. The [Investor Owned Utilities] lose revenue from NEM customers, particularly residential NEM customers, because those customers pay less to cover distribution costs through their volumetric rates. This revenue is recovered through increases in rates paid by all customers.” Therefore options satisfying this criterion better enable the utility to recover distribution costs which are incurred on an adopting customer’s behalf through collecting consumption charges for consumption from the grid.

Principles embedded in this criterion include: Grid valued fully, accurately, and impartially; Increase affordability of service to all customers; Ratepayer indifference

**Customer Choice**

This criterion asks how well the option enables the customer to make an informed choice in adopting DER and whether the option allows customer self-supply. Options satisfying this criterion reflect relative simplicity, clarity, and predictability over the life of an asset from an investing customer’s point of view, while enabling self-supply. Embodied in the criterion is recognition that customer generation needs to be financeable, which may imply fixed pricing for a period.

Principles embedded in this criterion include: DER valued fully, accurately, and impartially; Customer choice enabled, practical and informed; Valuation and incentives determined transparently

**Decarbonization**

This criterion asks how well an option contributes to high-renewable scenarios critical to achieving decarbonization targets, especially through encouraging co-location of solar with energy storage. Effective options increase grid flexibility, complementing variable renewable resources by responding to changes in renewable output, providing load shift, ramp, voltage, and/or frequency support. Successful decarbonization policy includes incentives for adopting and leveraging emerging inverter and storage capabilities.

Principles embedded in this criterion include: DER able to serve grid need; DER contribute to GHG reductions; Leverage new technology to serve customers and the grid; Peak-driven infrastructure investment minimized

Three principles of the evaluation that were not embedded in the criteria are “technologically neutral, competitive sourcing (Vision Element 2.C);” “unbundling grid and energy services,” and “California’s solar market grows sustainably.” The first was deemphasized because competitive sourcing through distribution and competitive wholesale markets remains an uncertain dimension of California’s energy markets. At this time the relative uncertainty of how these markets will work for customer generators, the size of the markets, and whether they will serve to support solar adoption lead the authors to focus on more near-term, predictable principles. The second, unbundling grid and energy services, was deemphasized because it was assumed achievable through any of the options analyzed. The third, growing California’s solar market sustainably, is treated as an overarching objective and addressed in the following section, “conclusions and recommendations.”

The following section evaluates the identified potential compensation structure options using these criteria.

**OPTION EVALUATION RESULTS**

The purpose of evaluating the compensation structure options using these criteria is to assess which structures may enable customer generators to make further contributions to the identified principles and criteria. Table 2 shows the relative advantages of each option.

**TABLE 2**

<table>
<thead>
<tr>
<th>OPTION</th>
<th>LOCATIONAL VALUE</th>
<th>GRID COST RECOVERY</th>
<th>CUSTOMER CHOICE</th>
<th>DECARBONIZE</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 NEM 2.0</td>
<td>•</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>2 Net Billing</td>
<td>•</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>3 NB + Grid Services</td>
<td>•</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>4 BASA</td>
<td>•</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>5 BASA Grid Services</td>
<td>•</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
</tbody>
</table>

**SCALE** BETTER • • • • • • WORSE

To explain the evaluation results we consider the relative strengths of each option sequentially by criterion.

The strengths of each option relative to the Locational Value criterion hinge on whether the core structure compensates a customer generator at a locationally differentiated value. NEM 2.0 and BASA are opposite in this regard, compensating
none and all of production at the Locational Value respectively. Net Billing allows for compensation of exports (only) at the Locational Value. The two Grid Services options rely on market based pricing which may be driven by relative costs and benefits, but unrelated to the LNBA valuation — the export price may be above or below the LNBA-informed price.

The strengths of each option relative to the Grid Cost Recovery criterion depend on whether the utility’s distribution costs are recoverable through the adopting customer’s volumetric rates. The options ascend in their ability to satisfy this criterion based on how much of the customer’s consumption results in a charge: more charges, more cost recovery.

The strengths of each option relative to the Customer Choice criterion reflect the relative simplicity of the transaction from a participating customer point of view and whether the option allows customer self-supply. Here Net Metering has historically proven effective, underpinning the adoption of solar by over 725,000 customers in California; however, the predictability of the customer’s return on investment is only as predictable as the underlying rate design, which is increasingly dynamic in California. At the more extreme edge of customer choice lie options defaulting customers into grid services markets, introducing new complexity relative to the alternatives and lowering the ease of engagement by customers. BASA is arguably the simplest transaction structure: customer gets paid a fixed export price for all production for a predictable period, as with a feed-in tariff; however, the structure prohibits customer self-supply, a significant limitation of customer choice. Net Billing mixes two options which are simple when separate, but potentially more complicated when put together.

Finally, the strengths of each option relative to the Decarbonization criterion depend on how well it enables the customer generation to support high-renewable scenarios. Relative to its predecessors, NEM 2.0 begins a transition to incentivizing grid integration through requiring customers to enroll in time of use rates, giving an adopting customer a nudge to orient and size their installation toward production profiles of relative advantage to the grid.

Net Billing goes further to support decarbonization. With Net Billing, the value of self-supply increases relative to exports, pushing the customer toward greater alignment and adoption of storage. Finally, options which default customers into grid services markets provide a distinct advantage: the sourcing of these resources follows an identified grid need. Relative to the “scatter shot” approach to DER deployment underpinning the other options, these advantages are significant from a decarbonization point of view. BASA does little to support decarbonization: neither self-supply nor grid services are brought to bear to support alignment of solar supply and demand. This short-coming could be mitigated by time-differentiated export prices, an option not explored in depth by this analysis.

Overall, the evaluation demonstrates net metering, other core structures, and the tool kit can be honed in pursuit of defined objectives. While Net Billing achieves average results across criteria, the others excel and fall short in various ways. Therefore, the relative weighting would have a significant impact on whether any option stands out.

CONCLUSIONS AND RECOMMENDATIONS

KEY QUESTIONS EMERGING FROM EVALUATION

This evaluation brings the following key questions into focus.

How should the success of NEM 2.0 be assessed?

NEM 2.0 implementation began in 2016 and 2017. While the impacts of this approach are not yet well understood, interconnection data show customer applications are slowing, as featured below in Table 3.16

<table>
<thead>
<tr>
<th></th>
<th>Q4 2015</th>
<th>Q4 2016</th>
<th>Delta</th>
<th>Q1 2016</th>
<th>Q1 2017</th>
<th>Delta</th>
<th>Q2 2016</th>
<th>Q2 2017</th>
<th>Delta</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Residential</td>
<td>810</td>
<td>906</td>
<td>12%</td>
<td>858</td>
<td>975</td>
<td>14%</td>
<td>1,360</td>
<td>386</td>
<td>-72%</td>
</tr>
<tr>
<td>Residential</td>
<td>41,527</td>
<td>33,630</td>
<td>-19%</td>
<td>39,634</td>
<td>26,484</td>
<td>-33%</td>
<td>36,875</td>
<td>16,517</td>
<td>-55%</td>
</tr>
</tbody>
</table>

To date the residential sector has slowed most significantly. Because submission of an interconnection application significantly lags development for non-residential customers, data for this segment will likely show a drop in forthcoming quarters.

There are numerous factors impacting solar adoption in California; concluding this trend is solely attributable to NEM 2.0 oversimplifies the analysis. We suggest the following questions be monitored in 2018 to inform future decisions concerning the effect of NEM 2.0 and contemporary factors. Insights gained from the current structure may be leveraged to support California’s next steps.

- **GHG Reductions**: How are existing customer generators contributing to decarbonizing California’s power supply? Will new resources have the same impact, diminishing, or increasing?

- **Market Conditions**: Are customers continuing to enroll in net metering? Is the market steady, growing, or contracting? What are growth expectations going forward?

- **Impact of TOU requirement**: Has requiring enrollment in TOU rates for residential net metering customers affected...

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enrollment in net metering? Has it affected the sizing and orientation of systems? Has it affected the adoption of storage technologies by residential customers?

- **Cost/Benefit:** Are the costs and benefits of NEM 2.0 improved relative to NEM 1.0?

An evaluation of these metrics and questions may serve as a useful foundation for future decision making regarding the merits of NEM 2.0.

**Is eliminating a customer’s self-supply practical and advantageous?**

The BASA options evaluated here would require regulatory limits on self-supply. For the relative advantages of those options to be gained, this limit would need to be physically practical, which may not be assumed. Data on customer owned generators directly serving load behind the meter out of parallel with the grid are limited, but anecdotal evidence suggest it may be impractical to limit the self-supply of motivated customers. The likelihood of customers “cutting the cord” if self-supply is precluded, even for a portion of their load, may warrant further evaluation.

In addition, self-supply has been a primary value-add for adopting customers. A compensation structure that eliminates this value stream must either replace it or, all other things being equal (e.g., customer generator system costs remain consistent), expect declining growth in customer adoption. The net billing options identified here preserve self-supply, effectively pitting retail rates against declining technology cost curves, especially that of storage. This competition may be a productive incentive to support storage adoption while enabling customer generators to make needed contributions to grid flexibility and affordability.

**What are the practical challenges of using the LNBA as proposed?**

The Net Billing and BASA options rely on the LNBA: the former as a source to inform pricing of exports; the latter for all production. As referenced here, the CPUC has indicated a consistent commitment to locationally differentiated incentives for customer generation, citing the potential for such targeting to reduce the need for investment in transmission and distribution grid infrastructure and local generation resources, while easing grid operations. That body has also acknowledged challenges facing the LNBA methodology in fulfilling this role and ordered further improvements.

Implementation of the ordered improvements will continue iteratively over time; perspectives on its effectiveness will differ; and uncertainty about its fitness for use in valuation will continue — of all conclusions in this analysis, this is perhaps most assured. These conclusions are doubly certain if the methodology is to serve a price-setting function. This is the hazard of a compensation framework which relies on administratively determined prices; one which is equally applicable to the administratively determined retail rate as it is for the LNBA. The buyer may be paying too much, or too little. Unless and until market pricing alternatives identified in the grid services options can serve as viable alternatives, there may be uncertainty about valuation.

Three further challenges to reliance on the LNBA deserve consideration: How will customers accept differentiated incentives? How will utilities process them? And how will vendors adapt marketing of DER under them? Customers may be confused or put off by receiving a different incentive than their in-laws a circuit over; utilities billing systems may require significant investment to track a level of granularity which has never been applied to retail ratemaking; and vendors may be challenged to effectively market or finance their services with specificity? There are three potential ways to address these challenges. First, technological solutions which empower the customer and utility to adapt to more price signals. Second, careful consideration of what the appropriate level of granularity might be. From the service territory, to distribution planning area, to groups of circuits, to circuits, to feeders, to individual customers: there is wide range of granularity enabled by the LNBA methodology. Third, offering all customers a base price for exports regardless of location with adders for locations of particularly value. Arriving at a practical level of granularity may require transition from broad to narrow and experimentation. Technologies which allow both customers and utilities to adapt may be tested, preferably with a sense of urgency.

**Are grid services markets viable?**

Net Billing and BASA structures would allow for exports or all production to enter grid services markets. Grid services markets include:

- **Wholesale Grid Services:** Under current CAISO tariffs, DER may bid market energy, regulation up, regulation down, spinning reserve and non-spinning reserve. However, active participation by DER providers has been limited. The CAISO has recently renewed an effort — its Energy Storage and Distributed Energy Resources stakeholder initiative — to address challenges associated with DER participation in wholesale markets. The CPUC has provided comparable commitments.

- **Distribution Grid Services:** Through the CPUC’s Distribution Resource Planning and Integration of Distributed Energy Resources proceedings, plus individual initiatives of Southern California Edison, numerous distribution grid services demonstration projects are underway. These demonstrations constitute the onset of California distribution services market, in which third-party aggregated DER provide capacity, voltage support, and resiliency services to the distribution system.

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17 D.17-09-026

18 Detailed service definitions at http://www.caiso.com/participate/Pages/MarketProducts/Default.aspx

19 Energy Storage and Distributed Energy Resources Stakeholder Initiative, CAISO.

20 D17-10-017; R.15-03-011. CPUC.

21 D.16-12-036. CPUC.
The integration of DER into wholesale and distribution markets has been a priority for California, but their viability remains uncertain. Through the referenced CAISO and CPUC initiatives the viability of grid services markets will become clearer. 2018 will be a pivotal year in this regard.

RECOMMENDATIONS

This evaluation attempts to evenly balance criteria and concludes that Option 2, Net Billing with exports compensated at the LNBA-informed export price for solar would be a substantial improvement to current policy, allowing for locationally differentiated compensation, improved grid cost recovery, and deeper decarbonization through storage enabled alignment of solar supply and demand.

This structure would lead to three potential outcomes:

• where the LNBA-based price paid on exports provides an adequate return, customers will adopt solar (with or without storage) in areas advantageous to the grid, easing grid planning and operations while lowering grid costs;

• where the LNBA-based price paid on exports does not provide an adequate return, customers are incentivized to maximize self-supply, most practically achieved through solar plus storage;

• where neither the LNBA nor storage are advantageous to the customer, they will maintain the choice to adopt while making increased contributions to grid cost recovery.

These advantages are more acute where and when mature grid services markets can replace the LNBA as a tool for pricing exports. As more experience with grid services is gained, these advantages may become increasingly practical.

To ease the transition from NEM 2.0 to Net Billing, two measures are recommended. First, enable Transferable Credits, allowing credit earned by a customer for exports to be transferred to other customers at the discretion of the customer generator. This will introduce liquidity into the market, especially if “size-to-load” requirements are lifted, allowing customers who are not in high-value locations to invest in those locations and receive corresponding reductions in their energy costs. Second, adopt temporary Market Transition Credits, smoothing the change from the current compensation levels to locationally differentiated levels. There are many ways this could be structured. One would be to “step-down” the Market Transition Credit in stages as the industry hits certain installed capacity benchmarks (similar to early California Solar Initiative designs). This step-down approach would have the added advantage of allowing for storage to scale up and reduce costs while signaling to industry that there will be a market for behind the meter storage.

Timely adoption of a Net Billing structure may also pave the way for grid friendly transportation electrification. Net metering would allow non-simultaneous netting of vehicle electrification load, an accounting tool which would undermine a principal benefit of vehicle electrification from a societal perspective (i.e., increased throughput leads to decreased rates). To the extent net metering continues into the next decade when electric vehicle adoption is forecasted to surge, a huge class of customers may come to expect low or zero cost service from the grid. On the other hand, a Net Billing structure would encourage electric vehicle customers to charge while the sun shines, or store their solar-generated energy to charge their vehicles at other times.

FIGURE 4
FROM NET METERING TO NET BILLING, SOLAR TO SOLAR PLUS STORAGE
A final advantage of Net Billing deserves consideration: Net Metering’s reliance on the retail rate limits the flexibility of California policymakers – the price paid to solar is intertwined with retail ratemaking, a clunky policy making process with implications and complications extending far beyond customer generation. This approach has supported customer adoption to date because retail rates were going up and solar costs were coming down. It is not difficult to imagine these trends being reversed, with federal trade or tax policy turning against solar. Net Billing on the other hand compensates exports at a price determined by California policy-makers, allowing for the adoption of anchors and adders with relative ease compared to Net Metering. In this sense, Net Billing allows California alone to determine whether solar is sustained.

Based on this evaluation we recommend California policy-makers move expeditiously to transition the state’s solar compensation framework toward a Net Billing structure. As provided, the transition may be eased in several ways and informed by data and insight gained through evaluation of NEM 2.0, helping to sustain growth in customer adoption and achieve the levels of forecasted solar adoption.
DEFINING ANCHORS AND ADDERS

Anchors

- **Minimum Bill**
  A minimum bill or minimum charge is the minimum amount that the utility can charge for service. This charge only applies to customers whose monthly usage falls below the amount required to support distribution and billing related costs. Also referred to as *minimum charge*.

- **Standby Rate**
  Standby rates are designed to cover the cost of standby electric service when a customer generator is not operating as intended. Currently California NEM eligible customer generators are exempt. Also referred to as *standby fees* or *standby charges*.

- **Non-Bypassable Charge**
  A volumetric charge applied on all customers’ bills (even if they purchase electricity from another supplier). For California NEM customers, this can apply to netted out consumption from the grid (1.0) or to total consumption from the grid during each metered interval (2.0).

  \[ \text{PGE: “Nonbypassable charges involve costs that were included in bundled service bills and are now separately listed. Customer generation departing load customers may receive bills from PGE for these charges even when they no longer receive electric service from PGE.”} \]

  \[ \text{Standby charges may be exempt from standby charges pursuant to PU Code Section 2827.} \]

- **Demand Charge**
  Charge for electric service based on the consumer’s maximum electric capacity usage and calculated based on the billing demand charges under the applicable rate schedule. Currently, demand charges only apply to commercial and industrial customers in California.

- **Interconnection Charges**
  A charge levied by network operators on other service providers to recover the costs of the interconnection facilities (including the hardware and software for routing, signaling, and other basic service functions) provided by the network operators.

- **Required Time of Use Rate**
  Requirement that a customer generator enrolls in a time of use rate as a condition of net metering.

- **Prohibition on Exports**
  Prohibiting the exports of power from a customer generator to the grid. This may be limited to particular intervals.

22 CPUC: “A minimum bill or minimum charge is the minimum amount that the utility can charge customers for service. This charge only applies to customers whose monthly usage falls below the amount required to support distribution and billing related costs...” Some utilities calculate minimum bill as a daily charge, which will add up this course of the month to roughly $5 or $10.” http://www.cpuc.ca.gov/General.aspx?id=12187

23 SCE: “The minimum charge (also referred to as the Balance of Minimum Charge or the ‘Bill of minimum charge’ as it may appear on your bill) is a delivery charge that helps support the maintenance and operation of providing electricity. This charge is calculated on a daily basis and only applies when your total Delivery Charges for the month fall below approximately $5 for those enrolled on California Alternate Rates for Energy (CARE), Family Electric Rate Assistance (FERA), multifamily and medical baseline rate plans or approximately $10 for all other residential users.” https://www.sce.com/wps/wcm/connect/0245d655-abae-4419-9e33-41ab30d8aa14/SCE_FrequentlyAskedQuestions_AA.pdf?

24 PGE: “The charges for the Minimum Bill include components for the generation of electricity. The delivery portion of the bill is used to pay for the electricity itself, while the delivery portion is used to pay for the transportation of the electricity over PGE’s grid. On March 1, 2016, the Minimum Bill, which previously was applied to the combined total of delivery and generation charges, will now only be applied to the delivery charge.” https://www.pge.com/en_US/residential/rate-plans/how-rates-work/rate-changes/minimum-bill-charges/minimum-bill-charges.page

25 SCE: “Standby is a Southern California Edison (SCE) electric rate for accounts with customer generators that interconnect to and operate in parallel with SCE’s electric system. On this rate, we provide back-up electric service when your generator(s) is not operating as intended.” https://www.sce.com/wps/wcm/connect/0f18366-cbé7a-4441-a7af-e9582ebbf0cd/Standby+FAQs+Sheet-v3_WCAG_K.pdf?

26 PGE: https://www.pge.com/tariffs/assets/pdf/starfbook/ELEC_SCHEDS_S%20(Sch).pdf


28 SDGE: “Solar Customers who are taking service under the Utility’s Net Energy Metering tariff are exempt from standby charges. In addition, Solar Customers which are less than or equal to one megawatt to serve load and who do not sell power or make more than incidental export of power into the Utility’s power grid are also exempt from standby charges. Non solar customers taking service under one of SDG&E’s Net Energy Metering schedules may be exempt from standby charges pursuant to PU Code Section 2827."

29 PGE: “Nonbypassable charges involve costs that were included in bundled service bills and are now separately listed. Customer generation departing load customers may receive bills from PGE for these charges even when they no longer receive electric service from PGE. Nonbypassable charges that may apply include the Public Purpose Programs (PPP) and the Nuclear Decommissioning (ND) Charge.” https://www.pge.com/en_US/business/services/alternatives-to-pge/departing-load-options/departing-load-options.page

30 PGE: D. 16-01-044, page 88 “Under [NEM 1.0], NEM customers pay the nonbypassable charges embedded in their volumetric rates. They do so, however, only on the netted-out quantity of energy consumed from the grid, after subtracting any excess energy they supply to the grid. NEM successor tariff customers must pay nonbypassable charges on each kWh of electricity they consume from the grid in each metered interval.” http://docs.cps.ca.gov/PublishedDocs/Published/G001/M158/K181/158181678.pdf

31 CPUC: Resolution E-4795 http://docs.cpuc.ca.gov/PublishedDocs/Published/G001/M163/K611/1639114992.PDF

32 CPUC: “A non-incident demand (‘NCD’) charge (in $/kW) is assessed on the customer’s maximum demand in any 15-minute interval during the billing cycle. A peak-related (or coincident) demand charge (‘CD charge’) is assessed on the customer’s maximum demand in any 15-minute interval during the peak TOU period” http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Uv/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2017/SB%202069_S%20Master%20Draft_final_5-12-17.pdf

33 PGE: “To help keep the supply of electricity reliable in California, some time-of-use rate plans, like A10 Time-of-Use, include a Demand Charge to encourage businesses to spread their electricity use throughout the day. This Demand Charge is calculated by using the 15-minute interval during each billing month when your business uses its maximum amount of electricity. As a benefit to this type of rate plan, regular electricity usage charges are approximately 30% lower than for a comparable rate plan without a Demand Charge—giving you the opportunity to save on your bill if you can lower your highest usage 15-minute interval.” https://www.pge.com/en_US/business/rate-plans/rate-plans/time-of-use/time-of-use-page

34 OECD: https://stats.oecd.org/glossary/detail.asp?ID=4965

35 CPUC: “Customer-generators with facilities under 1 MW must pay a pre-approved one-time interconnection fee based on each IOU’s historic interconnection costs.” http://www.cpuc.ca.gov/General.aspx?id=3800


Adders

• **Capacity Payments**
  Awarding a customer generator a payment or credit based on load-modifying or supply services that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure.\(^{38,39}\)

• **Locational Adders**
  Awarding a customer generator a payment or credit reflecting the resource’s value in certain locations.\(^{40}\)

• **Environmental Value**
  Awarding the customer generator a payment or credit for benefits based on reductions in the social cost of carbon and/or other environmental metrics.\(^{41}\)

• **Renewable Energy Credit**
  Awarding the renewable portfolio standard compliance credit to the customer generator rather than the off-taking utility.\(^{42}\)

• **Market Transition Credit**
  Awarding additional compensation to a customer generator during a defined period of time that recognizes the importance of continued clean energy development, the needs of the market, and the existence of values not yet identified.\(^{43}\)

• **Price Enrichment Based on Time of Delivery**
  Awarding exports based on the time of delivery, reflecting relative value at different points in time to the distribution system.\(^{44}\)

• **Grid Services**
  Awarding a customer generator payments for additional services provided to the grid (e.g., voltage support, distribution capacity, and/or reliability/resiliency) as apart of or incremental to self-supply credits.\(^{45}\)

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38 CPUC: D. 16-12-036, page 8 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF
42 CPUC: “Renewable Energy Credits (RECs) are among several factors that may affect the economics of solar and other renewable DG facilities, and as such may play an important role in driving the deployment of renewable DG in California and achieving the goals of California Renewables Portfolio (RPS). A REC confers to its holder a claim on the renewable attributes of one unit of energy generated from a renewable resource. A REC consists of the renewable and environmental attributes associated with the production of electricity from a renewable source. RECs are ‘created’ by a renewable generator simultaneous to the production of electricity and can subsequently be sold separately from the underlying energy.” http://www.cpuc.ca.gov/General.aspx?id=5913
43 NY PSC: Cases 15-E-0751 & 15-E-0082 Recognizing the importance of continued clean energy development, the needs of the market, and the existence of values not yet identified http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A-SF3592472A270C825808800517BDD?OpenDocument
## APPENDIX B

### SELECTED CUSTOMER GENERATOR COMPENSATION STRUCTURES, PROPOSED AND ADOPTED

<table>
<thead>
<tr>
<th>NET METERING</th>
<th>NET BILLING @ EXPORT PRICE</th>
<th>BUY ALL, SELL ALL @ EXPORT PRICE</th>
<th>ANCHORS</th>
<th>ADDERS</th>
<th>NOTES</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Hawaii Customer Self Supply</td>
<td>Export prohibited + Minimum bill</td>
<td>Export prohibited + Minimum bill</td>
<td>Driven by DG grid impact, Market slowly adapting</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2 CALSBA</td>
<td></td>
<td>NBC (partial)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3 SEIA/Vote Solar</td>
<td></td>
<td>Interconnection Charge</td>
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<td>4 Sierra Club @ TOU</td>
<td></td>
<td>TOU</td>
<td></td>
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<tr>
<td>5 CPUC NEM 2.0 @ TOU</td>
<td></td>
<td>Interconnection + NBC</td>
<td>Up to 7.5% of peak capacity</td>
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<tr>
<td>6 URA</td>
<td></td>
<td>Installed Capacity Fee (variation on interconnection charge)</td>
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<td>7 NRDC</td>
<td></td>
<td>Demand Charge</td>
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<tr>
<td>8 Nevada</td>
<td></td>
<td>Excess generation paid share of retail rate declining from 95% to 75% over time</td>
<td>Final policy pending</td>
<td></td>
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<tr>
<td>9 New Hampshire</td>
<td></td>
<td>Excess generation paid share of retail rate (100% T and G, 25% D) + NBCs on gross consumption + monthly true up</td>
<td>No statewide cap. Production meters required</td>
<td></td>
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<tr>
<td>10 Gridworks Option 2 @ locational value and 5 @ market price</td>
<td></td>
<td>Interconnection + NBC + managed demand charge</td>
<td>Transferrable Credits, temporary Market Transition Credit</td>
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<td>11 New York @ Locational Marginal Price</td>
<td></td>
<td>TOU + Demand + NBC + Monthly True-up</td>
<td>Capacity Values (wholesale, distribution, targeted distribution) + Environmental Value + Market Transition Credit</td>
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<tr>
<td>12 PUG &amp; @ Generation Rate</td>
<td></td>
<td>Minimum Bill + instantaneous netting + monthly true up</td>
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<tr>
<td>13 Hawaii CSS @ avoided cost (fixed)</td>
<td></td>
<td>Minimum Bill + Off Peak Export Uncompensated + Instantaneous netting</td>
<td>Exports at average annual marginal cost of generation</td>
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<td>14 Hawaii Smart Export @ TOD</td>
<td></td>
<td>Minimum Bill + Grid Charge (Variation on a minimum bill)</td>
<td>REC</td>
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<tr>
<td>15 SCE @ avoided cost</td>
<td></td>
<td>System Access Fee (variation on a minimum bill) + PPP + Grid Use Charge + TOU</td>
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<tr>
<td>16 SDG&amp;E (Unbundled Rate) @ LMP</td>
<td></td>
<td>Consumption at specific solar customer charge + Grid Charge + Demand Charge</td>
<td>Rate = 90% of T&amp;D, 100% of G in year one with T&amp;D stepping down 10% each year</td>
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<tr>
<td>17 Arizona @ declining proxy rate</td>
<td></td>
<td>Stand-by + Interconnection + Monthly True-up</td>
<td></td>
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<tr>
<td>18 Maine @ declining discounted retail rate</td>
<td></td>
<td>Gridworks Option 4 @ Locational Value and 5 @ Market Price</td>
<td>Transferrable Credits + temporary Market Transition Credit</td>
<td></td>
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<td>19 TURN @ gen + Adder</td>
<td></td>
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<tr>
<td>20 SDG&amp;E (Sun Credit) @ gen</td>
<td></td>
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<td>21 Gridworks Option 4 @ Locational Value and 5 @ Market Price</td>
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- Indicates adopted policy
- Indicates stakeholder proposal in CPUC R.14-07-002
NEW OPPORTUNITIES FOR SOLAR THROUGH GRID MODERNIZATION

How California & New York are Building Grids that Encourage the Growth of Distributed Energy Resources

AUTHORS:
Dave Gahl
Brandon Smithwood
Rick Umoff
EXECUTIVE SUMMARY

Lawmakers and utility regulators in California and New York have been extensively engaged in efforts to modernize the electric distribution grid. This paper draws on the experience of Solar Energy Industries Association (SEIA) staff in each jurisdiction and explains how these efforts are creating new opportunities for solar power. The paper describes the policy and political landscape in each state and summarizes the ways in which regulators are currently addressing grid modernization. We identify common elements of these efforts, which include: 1) updating utility system planning; 2) identifying alternatives to traditional utility investments; 3) establishing robust cost benefit frameworks; 4) modifying compensation frameworks to drive investments in distributed energy resources (DER), and 5) making utility investments in technologies that bring new functionality to the grid itself. Future papers will drill down into the details of these issues and discuss the pace of change, whether grid modernization efforts are bearing fruit, and obstacles to implementation.

INTRODUCTION TO GRID MODERNIZATION

For decades, electric distribution utilities have been upgrading their systems with new capabilities and better equipment to make their systems safer, more reliable and less costly to operate. But with more customers than ever producing their own clean power with solar and other DER, energy regulators, electric utilities and solar firms are now faced with new operational conditions as well as new opportunities.

ABOUT THIS WHITEPAPER SERIES

This series of SEIA policy briefs takes an in-depth look at state-level efforts to modernize the electric utility grid. Built during the last century, the United States electric grid was primarily designed to transport electricity from central station power plants to end-use customers. But with rapid growth of distributed energy resources such as solar, customers are increasingly taking charge of their own energy. Today’s electric grid must allow distributed energy technologies to flourish and provide reliable, low-cost power for consumers. Distributed energy resources, like solar, can also provide power where it is needed most and help avoid investments that a utility would otherwise need to make.

This series explores the elements of electric grid modernization, compares the ways in which two leading states are tackling these issues, and discusses how these efforts are creating new opportunities for solar power. Grid modernization efforts in states present significant risks and opportunities for solar. These efforts will determine how much new solar and other distributed energy resources can interconnect to the grid, identify areas where solar can provide grid services in lieu of utility investments, and in some states, will shape the future of net energy metering.

1 SEIA’s state affairs team is actively involved in proceedings in these two states, and has filed comments individually and as part of coalitions on key aspects of grid modernization dockets, and regularly engages with regulators on these and other issues.
The grid must be enhanced to encourage the widespread use of clean distributed energy resources, such as solar power. Grid upgrades must also be executed in a way that allows ratepayers to save money versus business-as-usual utility spending on distribution infrastructure. New value and compensation frameworks must also be created to facilitate the deployment of DER in strategic locations that can yield benefits to ratepayers.

Thus, energy regulators across the country, have started a host of dockets to consider changes to utility practices. California and New York have made considerable progress. But even with progress being made on the coasts, regulators and utilities are still in the earliest stages of modernizing the grid. As colleagues at More than Smart have described the process of creating a more modern grid, even leading states are still in the walking phase of More than Smart’s walk, jog, run framework. Shown in the figure, even leading states haven’t hit the ground running. We describe state efforts in California and New York below.

GRID MODERNIZATION IN CALIFORNIA

Passed in 2013, Assembly Bill 327 launched a series of regulatory proceedings that will profoundly shape California’s solar market, the largest in the country. The bill instructed the California Public Utilities Commission (CPUC) to undertake comprehensive residential rate reform for the first time since the energy crisis at the turn of the millennium, and move customers, on at least a default basis, to time-of-use rates by the end of the decade. This ambitious bill also tasked the CPUC with consideration of a NEM-successor tariff and review of utility Distribution Resource Plans.

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2 For most states DER penetrations are low enough that dramatic changes to grid capabilities and tariffs are unwarranted

In 2016, the CPUC retained full retail net metering provided that net metering customers: 1) pay non-bypassable charges on a gross- rather than net-basis; 2) pay a one-time interconnection fee; and 3) take service on a time-of-use rate. The CPUC also signaled that it would revisit the net metering tariff beginning in 2019 after significant changes to rates came to a conclusion. Come 2019, the decision stated, the Commission would also have insights and tools from proceedings looking at revamping distribution system planning, operations, and investment.

The move to more location-specific valuation, and possibly location-specific compensation, is occurring in California’s Integrated Distributed Energy Resources (IDER) Proceeding and Distributed Resources Planning (DRP) Proceeding. The DRP proceeding is developing a locational net benefit analysis (LNBA).

The LNBA is an evolution of the cost-effectiveness framework that the CPUC has used to evaluate distributed energy resources. Regulators have identified certain avoided costs that are “system level” values and do not vary by location across a utility service territory. They are also looking to improve and harmonize these system values through a process that is underway in the IDER proceeding. Transmission and distribution avoided costs, local capacity needs, and energy losses, which historically have been evaluated on a system-wide average basis will now vary at a much more geographically granular level: at the distribution planning area, substation level, or even circuit by circuit. Utilities are also evaluating other specific values such as voltage, power quality and reliability and resiliency and may add further values, such as asset life extension, data collection and situational awareness.

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5 California Public Utilities Commission, R.14-08-013 “Order Instituting Rulemaking on Distribution Resources Planning” (August 2014)
6 California Public Utilities Commission, R.14-10-003 “Order Instituting Rulemaking on Integrated Distributed Energy Resources” (October 2014)
The locational net benefit analysis represents a significant step forward in providing transparency about utility distribution system needs that have the potential to be met by distributed energy resources in lieu of traditional utility equipment. However, questions remain over how values are calculated, particularly for services such as voltage management, which are not well valued by evaluating the ability of a DER to modify load. There are also questions about whether an avoided cost methodology is itself appropriate and how utility system needs should be identified when needs change within a utility’s annual planning cycle.

GRID MODERNIZATION IN NEW YORK

New York’s overall policy objectives set in the State Energy Plan are to obtain 50% of the state’s electricity from renewables by 2030 and reduce greenhouse gas emissions by 40% from 1990 levels by the year 2030. To realize these goals, New York launched the Reforming the Energy Vision (REV) effort at the New York Public Service Commission (PSC). REV is a multifaceted initiative that aims to reduce ratepayer surcharges, create new markets for energy and technology companies, update aging utility infrastructure at a lower cost than business as usual, create a grid that’s less prone to outages, and reduce greenhouse gas pollution.

As part of REV, the PSC also updated its benefit cost framework. The PSC selected the state’s investor owned utilities as transactive grid operators and required them to prepare Distributed System Platform Implementation Plans (DSIPs) for transitioning to their new role. The PSC also required utilities to prepare a supplemental plan prepared jointly by all the utilities that proposed shared tools, processes and protocols to help operate a modern grid. The PSC directed the utilities to include adequate and reasonable assumptions about the uptake of DER in their load forecasts; provide third parties sufficient information to evaluate the best locations for solar systems; and describe a process for integrating cost effective DER at a system-wide scale. The initial DSIPs filed at the PSC included extensive analysis of utility grid operations.

The PSC has also pursued alternatives to utility investments through individual rate cases. In early 2014, the PSC required Consolidated Edison to make investments in distributed energy resources to avoid a $1 billion substation upgrade in Brooklyn/Queens. Called the Brooklyn/Queens Demand Management (BQDM) effort, the PSC then directed the state’s other investor owned utilities in their DSIP filings to identify similar areas where demand could be met with alternative investments.

A better understanding of the distribution grid will help solar projects, particularly by creating more certainty around the distribution system’s ability to interconnect new systems at different locations.

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At approximately the same time the PSC also launched an effort to develop an interim and long-term tariff for solar systems, and other DER providers, that would send more accurate price signals than the ones sent through retail rate net energy metering. Called the Value of Distributed Energy Resources (VDER) proceeding, this case attempts to unbundle the various components of value contained in electric rates, including energy value, capacity value, environmental and locational value\(^\text{10}\). Although regulators recognized that they did not have the analysis to provide precise valuation, they established proxy values and a transition credit mechanism to estimate these values for the first phase of the tariff. A second phase of the proceeding will attempt to provide more accurate valuations.

**THE COMMON ELEMENTS OF GRID MODERNIZATION**

Although public utility commission discussions about modernizing the electric grid are unfolding in different ways, the elements of grid modernization include the following five main concepts: 1) updating utility system planning; 2) identifying alternatives to traditional utility investments; 3) establishing robust cost benefit frameworks, 4) modifying compensation frameworks to drive investments in DER, and 5) making utility investments in technologies that bring new functionality to the grid itself. We unpack these elements below.

**Updated Utility System Planning and Transparency**

Arguably the foundation to all grid modernization efforts involves a fundamental shift in the way electric utilities plan to meet electric system needs. This planning should view all DER as an asset to the grid instead of a problem to be avoided, as it is sometimes perceived today.

A better understanding of the distribution grid will help solar projects, particularly by creating more certainty around the distribution system’s ability to interconnect new systems at different locations. Currently developers of larger projects face uncertain prospects regarding interconnection costs and timing for their projects: will the developer need to pay for distribution system upgrades? How long will the interconnection process take? Better planning ultimately involves the utilities releasing more detailed analyses of system needs such as line-by-line analysis of the ability of the existing grid to incorporate solar systems, often referred to as hosting capacity analysis. This information should be made available more frequently, not simply as part of three-or-five-year capital improvement plans. Accurate and timely hosting capacity analyses should take a considerable amount of uncertainty and delay out of the interconnection process.

Better planning can also ensure that unnecessary utility investments are avoided and opportunities for DERs to provide “non-wires alternatives” are identified. Solar firms can help provide solutions to grid problems, once they know what the problems are and what the actual constraints of the grid look like. To enable these opportunities, utilities should make more information about utility system operations available to solar companies on a regular basis.

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Establishing a Robust Benefit Cost Framework

Grid modernization efforts should also include establishment of a robust and transparent benefit cost framework to inform utility planning and ensure full and fair valuation of distributed energy resources vis-à-vis conventional utility investments. A benefit cost framework should take into consideration values including, but not limited to bulk system values, distribution system values, reliability and resiliency, and societal values. Additionally, the framework should consider costs associated with grid modernization efforts, including potential costs resulting from integrating DERs into the grid. The benefit cost framework can be used to place a value on DERs for the benefits they deliver, which may inform tariff development or solicitations of DERs on a portfolio basis.

Once utility planners have published better ongoing data about system needs, utilities, regulators and solar firms can then identify strategic locations on the grid itself where traditional capital investments can be offset by DER alternatives.
Identifying Alternatives to Traditional Utility Investments

Pilot projects in New York, California, and elsewhere have sought DERs in lieu of more traditional grid upgrades. California used DERs to meet needs created by the unexpected closure of the San Onofre Nuclear Generating Station\(^{11}\) and is repeating this process to meet needs in Santa Barbara\(^{12}\). New York is conducting a similar effort to avoid a distribution substation in Queens.\(^{13}\)

Improved utility distribution planning can facilitate using NWAs at scale. Once utility planners have published better ongoing data about system needs, utilities, regulators and solar firms can identify strategic locations on the grid itself where traditional capital investments can be offset by DER alternatives. NWAs are a new opportunity for DERs that can save ratepayers money by avoiding costly upgrades to the distribution system by promoting demand side management solutions instead.

Modifying Value/Compensation Frameworks

Another element of grid modernization involves developing compensation frameworks or rate design reforms to encourage DER providers to build projects in strategic locations. This includes making valuation more locationally dependent, developing solicitations, rates, and tariffs to meet needs in areas of the distribution system with identified needs, and potentially modifying underlying tariffs. In areas with high levels of solar deployment modification of tariffs could include net metering.

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Updating the Functionality of the Grid Itself

The last element involves making improvements to the functionality of the grid itself. These investments in infrastructure may include monitoring technologies to help more easily identify areas of system constraints, they may provide more real-time data about system needs, technologies that allow DER to even out power flows, and metering infrastructure to provide more accurate and timely information about customer electricity usage as well as billing. Utilities across the country vary widely on the extent to which they use these tools.

In this area of grid modernization there is another balance between utility and DER investment. Utilities may need investments, like distributed energy resource management systems (DERMs). But there are also potential opportunities for DERs, particularly with the capabilities of smart inverters which can provide much more data than utility equipment and have the capability to help manage power quality on the distribution system.

CONCLUSION

Leading states are tackling grid modernization through different means, but the elements of the discussions are strikingly similar. Furthermore, grid modernization discussions have moved beyond thought exercises by academics and think tanks. In California and New York, public utility commissions have required the execution of significant pilot programs and have begun requiring utilities to provide new analysis and redesign rates to accomplish their objectives.

But are utilities providing enough useful information on system planning in these docket's? How are new rate designs contributing to efforts to add more distributed energy resources into a more transactive grid? Will these efforts keep their current momentum or bog down based on lack of financial motivation on the part of utilities to participate? We will dive into these questions in future papers.
Celebrating its 43rd anniversary in 2017, the Solar Energy Industries Association is the national trade association of the U.S. solar energy industry, which now employs more than 260,000 Americans. Through advocacy and education, SEIA® is building a strong solar industry to power America. SEIA works with its 1,000 member companies to build jobs and diversity, champion the use of cost-competitive solar in America, remove market barriers and educate the public on the benefits of solar energy.
IMPROVING DISTRIBUTION SYSTEM PLANNING TO INCORPORATE DISTRIBUTED ENERGY RESOURCES

The Second in SEIA's *Improving Opportunities for Solar Through Grid Modernization* Whitepaper Series

AUTHORS:
Dave Gahl
Brandon Smithwood
Rick Umoff
EXECUTIVE SUMMARY

Built during the last century, the United States electric grid was primarily designed to transport electricity from large central station power plants to end-use customers. But with rapid growth of distributed energy resources, such as solar, resulting from falling costs and technological advances, customers are increasingly taking charge of their own energy. These resources offer the promise of a more innovative, economic, and cleaner electric grid.

This is a future in which distributed energy resources (DERs), such as solar power, will play an important role providing power and grid services where they are needed most. To reach this goal, however, distribution grid planning must evolve from a largely closed process (a “black box”) to one which allows transparency into system needs, plans for distributed energy resources growth, and ensures that the capabilities of distributed energy resources are fully utilized.

This paper is the second in SEIA’s series on grid modernization and focuses on distribution planning and operations, which is foundational to various facets of grid modernization. We start by reviewing the utility distribution system planning process today and identify key processes and concepts. Next, we discuss how two leading states are attempting to modernize distribution planning to both plan for distributed energy resources as well as leverage their capabilities.

ABOUT THIS WHITEPAPER SERIES

This series of SEIA policy briefs takes an in-depth look at state-level efforts to modernize the electric utility grid. Built during the last century, the United States electric grid was primarily designed to transport electricity from central station power plants to end-use customers. But with rapid growth of distributed energy resources such as solar, customers are increasingly taking charge of their own energy. Today’s electric grid must allow distributed energy technologies to flourish and provide reliable, low-cost power for consumers. Distributed energy resources, like solar, can also provide power where it is needed most and help avoid investments that a utility would otherwise need to make.

This series explores the elements of electric grid modernization, compares the ways in which two leading states are tackling these issues, and discusses how these efforts are creating new opportunities for solar power. Grid modernization efforts in states present significant risks and opportunities for solar. These efforts will determine how much new solar and other distributed energy resources can interconnect to the grid, identify areas where solar can provide grid services in lieu of utility investments, and in some states, will shape the future of net energy metering.
Distribution system planning is the process utilities undertake to evaluate their system needs based on forecasting demand, anticipating load shapes, and considering the tools available to them to meet system needs. The process includes two overlapping cycles: a multi-year review and funding cycle in utility general rate cases before a public utilities commission, and an annual planning process undertaken by utility distribution engineers. The former is an arcane regulatory process with some outside input from intervening parties, and the latter has been the sole purview of the utility.

Utilities upgrade their distribution grids based on forecast loads and replacement of aging equipment. Utilities annually review their distribution systems against load forecasts to identify areas where distribution system functioning may be challenged by new loads. They also use an ongoing asset management process to ensure that equipment, such as wooden poles, capacitor banks, and transformers, are replaced as they reach the end of their useful lives.

As part of the planning process, utilities evaluate whether an issue can be addressed by reconfiguring their distribution system. This reconfiguration involves shifting load through switches in the distribution system, moving load served by a substation and feeder to another feeder potentially served by another substation. If reconfiguration is insufficient to address the forecast need, the utility will plan investments in new infrastructure, such as substation upgrades, replacement of capacitor banks, or reconductoring of a feeder. Over the course of an annual planning cycle some investment needs will fall away while others will emerge as new system conditions arise.

With the advent of distributed energy resources, the basic tenets of this process remain intact. However, customers are not simply passive loads. Rather they increasingly have distributed energy resources. Where customers adopt these resources and how they are operated could mean substantially different utility needs in specific locations of the distribution grid over time. As distributed energy resources become more widespread distribution planning must move from simply planning, in a deterministic manner, based on forecast loads, to planning that is based on scenarios of distributed energy resource adoption and includes processes for guiding distributed energy resources to provide alternatives (“non-wire alternatives”) to traditional utility investments.
Enabling the distribution grid to readily incorporate distributed energy resources, and leverage their capabilities, begins with data. Efforts to change distribution planning and operations are, at their core, exercises in looking at the constraints on the distribution system. Will a new distributed solar system drive voltage beyond accepted limits? Will a new shopping center and housing development require a substation upgrade? The equipment that comprises the distribution system, along with the distribution grid's configuration, define what the distribution grid is capable of handling in terms of load and generation and where it might need to be upgraded.

The various analyses that states are pursuing in grid modernization proceedings are dictated by these grid constraints: 1) hosting capacity is a reflection of distribution grid constraints to accommodate new generation or load;\(^1\) 2) locational value of distributed energy resources is based on the value of avoiding distribution grid upgrades needed for reliability;\(^2\) and 3) non-wires alternatives are pursued in lieu of the identified upgrades underpinning locational values.

Given the importance of understanding the underlying grid needs that drive hosting capacity analyses and locational values, transparency is critical. If the cost-effectiveness of distributed energy resources, and/or their compensation, is going to be dictated by the cost of the needs they are offsetting, there is a reasonable expectation that those costs be publicly available.

Greater data transparency, and non-utility solutions for meeting grid needs, also provide a new opportunity to address an old problem of ensuring that utility expenditures are just and reasonable. To understand distribution system operations today, regulators, ratepayer advocates, and solar companies work through arcane quasi-legal processes to pull what data they can from the utilities using discovery requests, poring over utility filings, and carefully analyzing utility rate case testimony and exhibits. Further, utilities often provide these data in cumbersome formats such as locked spreadsheets or PDF files. While policymakers and interested stakeholders must use this information to determine whether utility investments in the electric grid are “prudent and reasonable,” they must also rely on this information when considering methods of modernizing our grid.

To achieve the needed level of data access, regulators must begin considering and implementing new data rules that allow for reasonable access to data about distribution system capabilities and needs. These data include the needs the system has (e.g., capacity, voltage issues, reliability, resiliency, etc.), the scale of that need (e.g., MW, kVAR) and the underlying causes of those needs.\(^3\)

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\(^1\) The next paper in this series will examine developing better hosting capacity analysis.

\(^2\) Other elements of DER locational value include the cumulatively avoided cost of energy and capacity, as well as cumulatively avoided transmission upgrade and maintenance costs.

\(^3\) An excellent resource for understanding what types of data are needed is “Unlocking Grid Data: Enabling Data Access and Transparency to Drive Innovation in the Electric Grid,” a white paper jointly authored by TechNet, SunSpec Alliance, and DBL Partners.
These data should be provided in a machine-readable format so that non-utility parties can use modern data analytics to evaluate utility needs and utility investment proposals, and identify areas where ratepayer savings can be realized by bringing distributed energy solutions to bear instead of more costly utility investments.

While reasonable protections must be made for customer privacy and security, protections have been defined to address concerns. Utilities should be specific about any unaddressed privacy or security concerns they believe exist. But such concerns should not be used as a rationale when the underlying concern is a reduction in utility capital expenditure that may result from better insights into utility distribution investment needs and potential third-party alternatives.

IMPROVEMENTS IN DISTRIBUTION PLANNING UNDERPIN NEW METHODS OF VALUATION AND TOOLS FOR INTERCONNECTION

Improved distribution planning yields data that underpins core products of grid modernization proceedings: Locational valuation, hosting capacity analyses, and non-wires alternative opportunities. Outlined below are ways that improved distribution planning provides the inputs to these grid modernization products.

1. Determining Locational Values

Historically, cost benefit analyses used for distributed energy resource programs, such as net-metering, have determined values for avoiding transmission and distribution that are averaged across a utility system. In reality, the value of distributed energy resources varies by location and what needs are driving utility investments. In some places, there may be a need for an expensive upgrade; in other locations, no forecast investments will be needed. Ensuring that all investments that could potentially be deferred or avoided by distributed energy resources are captured and valued requires transparency about distribution system needs, their drivers, and the costs of the utility investments needed to meet those needs. Short of these values it will not be clear to stakeholders whether these locational values are accurate and, therefore, if cost-effectiveness evaluations are fair.
2. Identifying Non-Wires Alternatives

Just as the type of utility distribution need, and the cost of the utility investment required to address that need, drive locational value, so too do those needs create the opportunity for non-wires alternatives (i.e., distributed energy resource alternatives to utility investments). Transparency on data about needs on the distribution system can ensure that distributed energy resource providers are afforded the opportunity to identify all opportunities where they may be able to provide more cost-effective solutions than a utility investment.

3. Making Interconnection Faster & Less Costly

Through power flow modeling, utilities use data about the equipment on- and configuration of- their distribution system to determine where upgrades are needed for their distribution systems due to load. The same underlying distribution grid data and power flow modeling can be used to identify how much additional distributed generation (or load, such as electric vehicle fast charging) can be interconnected to the utilities' distribution system. Transparency of these limitations both through hosting capacity maps, and the data underlying these maps, can help reduce interconnection costs and uncertainty for distributed energy resource developers.

Distribution Operations: The next frontier beyond improved planning

In addition to an evolving paradigm and process for grid planning there is discussion of new operational models. As new telecommunications technologies are developed and deployed by utilities, the ability of a utility to remotely monitor conditions and control equipment on the distribution system has increased. Telecommunications equipment (“SCADA”) has allowed utilities to remotely monitor and control major equipment like substations and switches. Smart meters have provided far more insight into conditions at individual customer locations. With the advent of distributed energy resources there is a question of whether further telemetry and controls are needed to monitor distribution grid conditions that may be altered by distributed energy resources.

Utilities are proposing new equipment and software to monitor their distribution systems at a more granular level and potentially to control distributed energy resources directly or through aggregators. But the natural tendency of utility planners and operators to desire control over equipment on the grid should be resisted in favor of providing opportunities for customer devices and third party IT infrastructure, using the internet, to demonstrate their full capabilities to provide the necessary services at lower costs. Using existing third party equipment will deliver more value to customers than allowing utilities to make potentially expensive new investments and passing on those costs to ratepayers.

Going beyond new technology changes, operations of the distribution grid should change the role the utility plays as a distribution system operator. Utility operations could transition from a distribution system operator (DSO) where grid conditions are managed through utility operation of traditional infrastructure to an independent distribution system operator (IDSO) where a financially disinterested entity can orchestrate the operation of resources, both utility and third-party owned, to meet distribution system needs. For example, in New York the utilities have been directed to estab-
lish a distribution system platform provider (DSP) for their service territory. The DSP will be operated by the utility and generate revenue through the establishment of to-be-determined platform service fees, but remain functionally separated by a firewall from the utility’s traditional role as a distribution company.

As distributed energy resources meet customer needs, local distribution needs, and wholesale market needs there will also need to be a capability for the DSO or IDSO to better communicate with the bulk transmission system operator to understand how transmission-level dispatches of DERs will impact locations on the distribution grid and the transmission system.

LEADING STATE EFFORTS TO REFORM UTILITY DISTRIBUTION PLANNING

1. California

In response to Assembly Bill 327, California’s major utilities have filed distribution resources plans (DRPs). The methodologies of these plans have been under further development in the Distribution Resources Planning (DRP) proceeding and Integrated Distributed Energy Resources (IDER) proceeding.

The DRP proceeding has evaluated geographically-granular forecasts of distributed energy resources down to the feeder-level. These forecasts will inform a revised distribution planning process, potentially including a Grid Needs Assessment\(^4\) which will outline all needs, both for traditional distribution grid upgrades as well as any grid modernization to accommodate DER.

This Grid Needs Assessment will provide the inputs to a deferral framework, which will identify projects that are deferrable or entirely avoidable through the deployment of distributed energy resources. This assessment, in turn, will determine locational net benefits in the locational net benefit analysis.

\[\text{Distribution planning must become more dynamic, and the methods applied must adapt to and account for the changing environment.} \]

- NY PSC

\(^4\) CPUC Energy Division Staff “Staff Whitepaper on Grid Modernization” (April 2017) [http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M186/K580/186580403.PDF](http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M186/K580/186580403.PDF)
Data access has been an area of disagreement between the utilities and distributed energy resource providers. The Commission has established rules for customer privacy, which include aggregation of customer data to ensure their individual usage is not publicly disclosed. The utilities have argued, however, that though much of this data may not result in privacy or security concerns it is “market sensitive,” meaning that if they disclosed the costs of various needs on the distribution system any non-wires alternative solicitation would result in distributed energy resource companies bidding to the utilities’ cost. This is an illogical outcome, but the argument has heretofore meant that only indicative values are available for the locational value of distributed energy resources.

Distribution system operations are being discussed in several forums. Southern California Edison’s current recent general rate case\(^5\) is exploring new tools for operating the distribution system, with one of their rationales being operation at high penetrations of distributed energy resources. Interconnection rules have established communications standards and pathways for the utilities to communicate with distributed energy resources directly.\(^6\) Ongoing conversations between the California Independent System Operator (CAISO) and the state’s utilities are seeking to determine how distribution utilities and the ISO can better coordinate as distributed energy resources participate in the ISO’s markets.\(^7\)

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\(^{5}\) “Test Year 2018 General Rate Case Application of Southern California Edison” California Public Utilities Commission docket A.16-09-001.

\(^{6}\) Each utility has filed advice letters which will, beginning in March 2018 or 9 months following the establishment of relevant SunSpec standards, will require smart inverters to be capable of three different communications channels.

2. New York

The New York Public Service Commission (PSC) also directed the utilities to file plans to better identify and integrate distributed energy as a major means of meeting distribution utility infrastructure and operational needs. The PSC stated, “Distribution planning must become more dynamic, and the methods applied must adapt to and account for the changing environment.” The PSC identified two key areas of advanced planning: integrated system planning and hosting capacity analysis.

CONCLUSION

Utility distribution planning has begun to move from a focus on meeting passive loads to anticipating distributed energy resources, both in terms of how many DERs can be expected on the system and where these resources are likely to be located. To benefit ratepayers and unlock the full value of a modernized grid, updated distribution planning must leverage DERs, such as solar, to meet distribution needs where they may have traditionally used utility installed, owned, and operated equipment. Some states are leading the way toward reforming distribution planning, but much more work must be done. A key for regulators will be to guard against over-investment by utilities under the rationale of enabling distributed energy resources in the marketplace. Distribution planning done correctly will create opportunities for solar firms and other distributed energy resources, better value for customers, and help state’s meet their energy and economic development goals.

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8 See Market Design and Platform Technology Report at 50
9 See DSIP Guidance at 9
Celebrating its 43rd anniversary in 2017, the Solar Energy Industries Association is the national trade association of the U.S. solar energy industry, which now employs more than 260,000 Americans. Through advocacy and education, SEIA® is building a strong solar industry to power America. SEIA works with its 1,000 member companies to build jobs and diversity, champion the use of cost-competitive solar in America, remove market barriers and educate the public on the benefits of solar energy.
HOSTING CAPACITY: USING INCREASED TRANSPARENCY OF GRID CONSTRAINTS TO ACCELERATE INTERCONNECTION PROCESSES

The third in SEIA's *Improving Opportunities for Solar Through Grid Modernization* Whitepaper Series

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EXECUTIVE SUMMARY

Built during the last century, the United States electric grid was primarily designed to transport electricity from large central station power plants to end-use customers. But with rapid growth of distributed energy resources, such as solar, resulting from falling costs and technological advances, customers are increasingly taking charge of their own energy. These resources offer the promise of a more innovative, economic, and cleaner electric grid.

In recognition of the growing role, value, and opportunity of distributed energy resources, a number of states across the country are looking at how distribution system planning, operations, and investment must change. This paper series examines the potential changes being considered and the opportunities for solar and other distributed energy resources.

This paper is the third in SEIA’s series on grid modernization and focuses on improving interconnection with hosting capacity analyses. As with the rest of the papers in this series, the experiences of two leading states, California and New York, are examined.

ABOUT THIS WHITEPAPER SERIES

This series of SEIA policy briefs takes an in-depth look at state-level efforts to modernize the electric utility grid. Built during the last century, the United States electric grid was primarily designed to transport electricity from central station power plants to end-use customers. But with rapid growth of distributed energy resources such as solar, customers are increasingly taking charge of their own energy. Today’s electric grid must allow distributed energy technologies to flourish and provide reliable, low-cost power for consumers. Distributed energy resources, like solar, can also provide power where it is needed most and help avoid investments that a utility would otherwise need to make.

This series explores the elements of electric grid modernization, compares the ways in which two leading states are tackling these issues, and discusses how these efforts are creating new opportunities for solar power. Grid modernization efforts in states present significant risks and opportunities for solar. These efforts will determine how much new solar and other distributed energy resources can interconnect to the grid, identify areas where solar can provide grid services in lieu of utility investments, and in some states, will shape the future of net energy metering.
WHAT IS HOSTING CAPACITY?

One concept that has garnered considerable attention is the idea of developing better assessments of DER “hosting capacity” as part of the planning process. Hosting capacity is the amount of DERs that the electric distribution system can reliably accommodate without significant grid upgrades. In conducting a thorough hosting capacity analysis, utilities consider voltage/power quality constraints, thermal constraints, protection limits, safety, and overall reliability to arrive at a capacity (kW, MW) of new generation or load which can be accommodated at a specific location on a distribution circuit.

Hosting capacity depends heavily on location. It is unique to specific feeders and is time varying. Given that customer needs are always changing, a hosting capacity analysis conducted today may yield different results than an analysis prepared five years from now. In general, carefully crafted hosting capacity analysis can give DER developers insight into where on the grid DERs can interconnect and potentially, on a forecast basis, where utility upgrades may be needed in anticipation of DER growth.

RULES OF THUMB NO LONGER WORK FOR INTERCONNECTION

Historically, general “rules of thumb” have been used to provide a preliminary estimation of available capacity for interconnecting new distributed generation. These conservative approximations often act as a significant and unnecessary barrier to many projects. These rules of thumb include generation as a percentage of peak load on a circuit or a percentage of minimum daily load. For example, since the late 1990s California’s interconnection procedures for small generators (Rule 21) has established a threshold for supplemental interconnection review of 15% of peak demand. If the total installed distributed generation capacity on a line segment exceeds 15% of the line section peak annual load, further analysis must be undertaken before the project is approved. This standard has become common around the United States.

As an alternative rule of thumb, a percentage of minimum daytime load has often been used as a threshold, since the minimum load during the time when solar is producing is most relevant to whether the generation will cause challenges for the distribution system by producing energy flows back towards the substation.

Both installed capacity as a percentage of peak load or minimum daily load are inaccurate. Indeed, research from the Sandia National Labs have found no correlation between peak load and hosting capacity. Instead, accurate hosting capacity analysis requires that the characteristics of an individual line segment in a distribution system are assessed to ensure that a potential solar generator or other distributed energy resources, such as combined heat and power generator or electric vehicle charging, do not result in violations of power quality/voltage, safety, protection, thermal or safety/reliability limits.

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The process of interconnecting a solar system requires assurances that the operation of the system will not impair the safe, reliable functioning of the distribution and transmission system. For larger DERs, this requires engineering studies which take significant time and can add substantial, and potentially unnecessary, expenses for project developers to upgrade the distribution system to accommodate the connecting DER.

Currently, when generators fail certain tests in the interconnection process they must undergo an interconnection study process. These tests often include the previously mentioned rule of thumb limits as an initial screen. In the subsequent interconnection study process, power flow modeling is performed by utility engineers to ensure that the generator will not violate any of the limits to power quality, safety, etc. In many cases the generator may fail the initial “rule of thumb” screens but ultimately learn that the distribution grid can easily accommodate their generator. However, even when this happens substantial costs are borne by the developer and customer in foregone bill savings and costs associated with project development delays. In some cases, large distribution grid upgrades can be identified which make the project uneconomical. News of these costs come after the solar company has invested substantial cost in acquiring the customer and designing the project.

A hosting capacity analysis uses the engineer’s tools proactively to determine an amount of capacity that can be interconnected on any individual line segment. By using these power modeling tools to generate hosting capacity we can replace rules-of-thumb, like minimum daily load, and improve the interconnection process. Indeed, as we have shown, work is underway in several states to generate maps which have up-to-date amounts (in megawatts) of available integration hosting capacity.

Case Study: Rule-of-Thumb Hosting Limits Shut Down Hawaii

In 2013, Hawaii Electric Company (HECO) placed a moratorium on new solar interconnections on line segments where solar capacity exceeded 120% of minimum daily load. Following testing by the National Renewable Energy Laboratory, in collaboration with SolarCity and HECO, the limit was raised to 250% of minimum daily load with new systems required to install smart inverters. The market was able to reopen but only after a severe interruption based on an overly conservative rule-of-thumb interconnection test.
Hosting capacity analysis creates new opportunities for greater cost certainty and speed in interconnection. Hosting capacity analysis could also help developers plan their sales to avoid trying to interconnect in areas where hosting capacity is limited. However, hosting capacity also creates opportunities for identifying creative solutions for integrating a DER system that may not otherwise fit within available hosting capacity. Currently accommodating a distributed solar system while avoiding distribution system upgrades may be possible through a back-and-forth discussion between the developer and utility engineers modeling the distribution grid, but that is a drawn out process that leads to project delays. By providing a granular understanding of hosting capacity analysis - which hours are challenging and what conditions, such as voltage, are limitations - project developers can provide solutions to address that limitation without utility upgrades.

Figure 1: Snapshot of Pacific Gas & Electric Hosting Capacity Map

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NEW OPPORTUNITIES CREATED BY HOSTING CAPACITY

Hosting capacity analysis creates new opportunities for greater cost certainty and speed in interconnection. Hosting capacity analysis could also help developers plan their sales to avoid trying to interconnect in areas where hosting capacity is limited. However, hosting capacity also creates opportunities for identifying creative solutions for integrating a DER system that may not otherwise fit within available hosting capacity. Currently accommodating a distributed solar system while avoiding distribution system upgrades may be possible through a back-and-forth discussion between the developer and utility engineers modeling the distribution grid, but that is a drawn out process that leads to project delays. By providing a granular understanding of hosting capacity analysis - which hours are challenging and what conditions, such as voltage, are limitations - project developers can provide solutions to address that limitation without utility upgrades.

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A. Leveraging the Capabilities of Smart Inverters

Historically, inverters have had the humble role of converting direct current from solar systems into alternating current which could be distributed within a building or exported back to the distribution grid. However, the evolution of smart inverter technology and standards are increasing their capability. Starting in September 2017, all new solar systems applying for interconnection in California will need to have inverters enabled to provide some relatively basic grid support functions that inverters can do autonomously, including the ability to “ride-through” voltage and frequency disturbances rather than tripping off as current inverters do. These rules will soon become standard features of interconnection in more states around the country as the IEEE 1547 interconnection standard is updated.

The updated IEEE standard is expected, by the end of the year, to require providing reactive power when voltage conditions go outside of an acceptable range. This new requirement in the standard should expand hosting capacity in all locations where inverter-based distributed energy resources are installed. Figure 2 below from the Electric Power Research Institute shows how Volt/VAR control can enhance hosting capacity.

![Figure 2: Improving Hosting Capacity Through Inverters (Volt/VAR control)](image)

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4 Hawaii has adopted similar rules. Rule 14H
5 Electric Power Research Institute as presented in May 6th, 2016 Presentation by Rachel Peterson, Advisor to California Public Utilities Commissioner Michael Florio, available at: [https://www.slideshare.net/sandiaecis/wl-1cpuc-for-epri-sandia-modeling-workshop-6-may-2014](https://www.slideshare.net/sandiaecis/wl-1cpuc-for-epri-sandia-modeling-workshop-6-may-2014)
B. Enhancing Hosting Capacity Through Storage and System Configuration

In the past, interconnection studies would make limiting assumptions about system operations. For example, maximum potential solar production from a system might be compared to minimum daily load which occurs during spring or fall months when solar production is reduced. Knowing that minimum limitation, such as voltage on low-load days in shoulder months, could allow for a developer to modify their project to avoid distribution upgrades. For example, inverter settings could be set to limit real power output during these shoulder months or battery storage could be added to a solar system to avoid exports at these problematic hours. In California, the utilities have created “agnostic” hosting capacity curves which can allow for a myriad of project generation or load curves, better reflecting different DER configurations (e.g., solar plus storage) and providing for creative solutions to interconnecting projects where there are hosting capacity limitations.

Figure 3: Identifying Hosting Capacity

THE INTEGRATION CAPACITY ANALYSIS: HOSTING CAPACITY IN CALIFORNIA

California’s IOUs are recognized for having some of the fastest interconnection processes in the country, largely as a result of automating interconnection application processes. However, larger projects can be delayed based on interconnection screens. California’s interconnection process, Rule 21, includes rule-of-thumb limits in its Fastrak interconnection process. Often projects will fail these screens and have to undergo an interconnection study. In order to limit uncertainty for the developers, a 2016 Commission decision (D.16-06-052) created a requirement for upgrades which might be identified and bounded the costs which developers would ultimately need to pay if costs exceeded those limits.

Simultaneous to the Commission’s efforts to bound the costs of unexpected results from interconnection studies, the Commission and utilities have been working on hosting capacity analyses (known as “Integration Capacity Analyses” or “ICA”). California’s three largest utilities completed ICA pilots at the end of 2016 and are currently working with a working group to refine their methodology.

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The Commission is expected to adopt the ICA this year and has opened a proceeding to revise the interconnection process. The ICA should allow for the replacement of several screens in the fast track interconnection process and hopefully allow for creative project design opportunities to avoid distribution upgrades where there may be a lack of hosting capacity.

NEW YORK: A FOUR STAGE PROCESS TO DEVELOP HOSTING CAPACITY MAPS

In New York, the Public Service Commission (PSC) approved a four-stage process for improving hosting capacity analysis. While there is still significant work to be done to implement this process, the four phases are as follows:

- **Stage 1**: Use of Red Zone maps to identify the layout of overhead circuits and indicated whether the interconnection of certain sized DG would have a higher or lower cost;
- **Stage 2**: Calculate hosting capacities using the Distribution Resource Integration and Value Estimation (DRIVE) tool developed by the Electric Power Research Institute (EPRI). This tool is based on circuit models and therefore requires circuit analyses.
- **Stage 3**: Development of “heat” maps that represent capacity ranges using color schemes consistent across utilities. The hosting capacity ranges will be based on the circuit characteristics and will provide information about currently interconnected DERs, as well as DERs in the interconnection queue. The data will be updated regularly by the utilities.
- **Stage 4**: Hosting capacity data to be further refined at more granular levels, such as incorporating host capacity data on the sub-feeder level and the locational value that interconnection of DERs would have on a particular feeder and/or substation.

Finally, the utilities have proposed ways in which hosting capacity can be increased by resolving voltage, thermal, and protection violations that limit additional DERs from interconnecting. Solutions include grid-side measures, operational measures, and customer-sided solutions. While questions remain about the New York utilities’ ability to meet the timeframes required by the PSC for completing these analyses, the Commission’s recognition that new processes must be put in place for determining an accurate hosting capacity is a small step in the right direction.

CONCLUSION

As distributed energy resources proliferate, ensuring that interconnection delays and costs do not stymie their deployment is critical. Improved utility distribution system planning tools and processes allow for an accurate assessment of how much new distributed energy resource capacity can be interconnected at any point in the distribution grid. As leading states are close to implementing hosting capacity analyses system wide we should begin to see the benefits in those states and have lessons for other states to follow.

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7 California Public Utilities Commission, Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21, Rulemaking 17-07-007 https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO
Celebrating its 43rd anniversary in 2017, the Solar Energy Industries Association is the national trade association of the U.S. solar energy industry, which now employs more than 260,000 Americans. Through advocacy and education, SEIA® is building a strong solar industry to power America. SEIA works with its 1,000 member companies to build jobs and diversity, champion the use of cost-competitive solar in America, remove market barriers and educate the public on the benefits of solar energy.
GETTING MORE GRANULAR: HOW VALUE OF LOCATION AND TIME MAY CHANGE COMPENSATION FOR DISTRIBUTED ENERGY RESOURCES

The fourth in SEIA's Improving Opportunities for Solar Through Grid Modernization Whitepaper Series

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EXECUTIVE SUMMARY

Built during the last century, the United States electric grid was primarily designed to transport electricity from large central station power plants to end-use customers. But with rapid growth of distributed energy resources (DER) resulting from falling costs and technological advances, customers are increasingly taking charge of their own energy. These resources offer the promise of a more innovative, economic, and cleaner electric grid.

DER, such as solar power, will play an important role providing power and grid services where they are needed most. To reach this goal, however, distribution grid planning must evolve to allow more transparency into system needs, enable more robust data exchange between utilities and DER providers, and include DER as a standard component of utility load forecasts.

This paper, the fourth in SEIA’s series on grid modernization, focuses on the ways in which the location of a DER can provide various grid benefits and may lead to changes in DER compensation. As with the rest of the papers in this series, the experiences of two leading states, California and New York, are examined. These two states are in the process of conducting extensive work examining new locational values and location-based tariffs and can serve as models for other states that are considering similar policies.

ABOUT THIS WHITEPAPER SERIES

This series of SEIA policy briefs takes an in-depth look at state-level efforts to modernize the electric utility grid. Built during the last century, the United States electric grid was primarily designed to transport electricity from central station power plants to end-use customers. But with rapid growth of distributed energy resources such as solar, customers are increasingly taking charge of their own energy. Today’s electric grid must allow distributed energy technologies to flourish and provide reliable, low-cost power for consumers. Distributed energy resources, like solar, can also provide power where it is needed most and help avoid investments that a utility would otherwise need to make.

This series explores the elements of electric grid modernization, compares the ways in which two leading states are tackling these issues, and discusses how these efforts are creating new opportunities for solar power. Grid modernization efforts in states present significant risks and opportunities for solar. These efforts will determine how much new solar and other distributed energy resources can interconnect to the grid, identify areas where solar can provide grid services in lieu of utility investments, and in some states, will shape the future of net energy metering.
Electricity supply and demand must be balanced on an almost instantaneous basis at all times and in all locations of the power grid. To accomplish this, utilities must plan their systems around the hours when demand is forecasted to be highest and ensure that they have enough capacity to meet this demand. To meet reliability requirements, utilities must also maintain an additional amount of capacity beyond this peak load as a reserve margin. Each part of the utility system, whether the total capacity of the power plants, the amount and size of transmission lines, or the equipment on a distribution circuit, must be designed to provide reliable service during the most challenging times that equipment is expected to face. DER such as solar PV can help avoid or delay investment in the grid infrastructure required to meet these needs by reducing load at the exact time when utility systems are most challenged. These resources can also be actively targeted to meet a distribution system need, through a solicitation, tariff or other mechanism.

**Defining Locational Value**

As part of their annual distribution planning process, utilities look closely at expected needs on the distribution grid in the following ten years. During this process, utility distribution engineers consider localized load forecasts based on demographic trends, such as population growth and household size, as well as planned construction, such as new housing communities and shopping centers. Based on current conditions and its forecast, the utility will determine if and where there are emerging or anticipated deficiencies for capacity or power quality. For example, expected home construction in an area may lead to projected load growth that requires replacing wiring on a distribution circuit, adding capacity to a substation, or some other upgrade. These projections are based both on the location of deficiencies as well as the specific time of day driving those needs. For example, certain circuits may need additional capacity to meet planned loads on hot summer afternoons, while other circuits may have high winter morning heating loads that must be addressed.

Once the utility understands its local capacity needs, the cost of the project – and thus the value of avoiding the project – can be determined. The cost of the project or projects needed to address an identified shortcoming should be based on the incremental cost of adding a unit of capacity to that area, for example $/kW-year. This is called the “marginal cost of capacity” as it reflects the cost to add new capacity, not the cost of the capacity already on the grid. The locational value of a DER system can be determined based on the contribution the resource makes to meeting that need, whether through energy, capacity, or reactive power produced during the hours when there is a need in that location. For example, if a set of circuits that peak in late August hours are driving the need for a multi-million-dollar substation, the locational value for a DER in this area would be equal to the marginal cost of adding that new substation capacity and any other needs on the distribution grid driven by those peak hours.
Getting Time-Value Right: Time of Use Rates
Locational value is based both on where distribution grid upgrades are needed as well as the hours that are causing the need in that location. However, other factors that drive the need for new power plants or transmission expansion projects also vary across times. Properly designed time-of-use rates can be a way to align the behavior of all utility customers – both with and without solar – to the needs of the grid. TOU rates may also be designed to support new technologies such as energy storage. For example, SEIA has proposed a suite of solar-plus-storage TOU rates in a recent Pacific Gas & Electric rate case.¹

Defining Locational “Hot Spots”

![Figure 1: New York Local System Relief Value Map](image1)

![Figure 2: California Distribution Cost “Hot Spots”](image2)

Using Locational Value
Locational analysis can be a useful tool in unlocking the additional value that solar can provide to distribution system. Gaining a better understanding of locational value can help guide the placement of DER – including solar – to high value locations, provide the basis for compensation through location-specific utility solicitations or tariffs, and improve the accuracy of DER cost effectiveness evaluations. However, as useful as locational value is in some contexts, it should not necessarily replace other policies such as net metering, especially in emerging markets. Net metering has a demonstrated record of creating strong markets for renewables, and a location-based-variable tariff has yet to be demonstrated anywhere in the US. Only when emerging markets have reached a certain level of maturity should regulators begin the process of considering more location-based compensation frameworks.


² Snuller Price, Energy and Environmental Economics (E3) Presentation to the New York REV Value Stack Working Group (September 20, 2017). Available at: [http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a8a5f3592472a270c8525808800517bddd/$FILE/E3%20DER%20Workshop%20California%20LNBA.pdf](http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a8a5f3592472a270c8525808800517bddd/$FILE/E3%20DER%20Workshop%20California%20LNBA.pdf)
Guiding DER to High Value Locations

Locational value can be used to guide resources to high value locations. Utilities can create, and should publish maps\(^3\) showing the specific locations of any needs on the distribution system, the specific grid constraints to avoid the need (e.g., high loads during hot late summer afternoons), and the value of the avoidance in terms of dollars per amount of capacity. If a developer knows in advance that there will be a utility solicitation for the identified needs, it can begin seeking customers or project sites in anticipation of the opportunity to bid in its projects.

![Figure 3: Locational Value Map for a Distribution Planning Area in Pacific Gas & Electric's Service Territory\(^4\)](image)

Providing the Basis for Compensation

In addition to competitive utility solicitations, there are alternative means of providing targeted tariffs, programs or incentives to drive DER to locations to meet identified needs. If identified needs are too small or have too short of a lead time to be met through a competitive solicitation, the utility could have a tariff- or program-based mechanism that can step in on short notice. For example, voltage issues are often very isolated and managed with small utility investments. However, smart inverters are increasingly being deployed widely and can be used to provide voltage management services in the locations where a utility has challenges managing voltage within an acceptable range. In addition, tariffs enable customers of all stripes to adopt solar and other DER, which delivers the generalized grid benefits we discuss, but also ensures that a state’s clean energy market grows equitably in a manner that distributes the social, environmental, and economic benefits to all ratepayers. This is an emerging topic and it is expected that California’s Integrated Distributed Energy Resources proceeding will explore non-solicitation based sourcing mechanisms.

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\(^3\) For example, see Pacific Gas & Electric’s demonstration Locational Net Benefit Analysis map. Available at: [https://www.pge.com/b2b/energy-supply/wholesaleelectricssuppliersolicitation/PVRF0/DemoBMap/Demo8.html](https://www.pge.com/b2b/energy-supply/wholesaleelectricssuppliersolicitation/PVRF0/DemoBMap/Demo8.html)

\(^4\) Screenshot from Pacific Gas & Electric’s demonstration Locational Net Benefit Analysis map.
Improving Cost-Effectiveness Evaluations

California's Locational Net Benefit Analysis is a modification of the state's Distributed Energy Resources Avoided Cost (DERAC) calculator. The DERAC is a spreadsheet tool incorporating utility costs that can be avoided by DER and is used to evaluate the cost-effectiveness of all demand-side programs in California, including net metering. The locational net benefit analysis has sought to take state-wide averaged avoided costs for transmission and distribution and unbundle these values into specific sub-categories. The Commission has ordered the utilities to modify the DERAC tool to create a spreadsheet which incorporates locational values for approximately 500 distribution planning areas. While this may, in theory, provide a more precise view of the cost effectiveness of different DER programs, one must be cautious not to overestimate the precision of long-term locational forecasts that underpin these types of tools.

Likewise in New York, to help inform the ongoing Reforming the Energy Vision (REV) effort, the Public Service Commission (PSC) published a Benefit Cost Analysis (BCA) Framework Order that sets out the standard elements that enable a fair comparison of benefits and costs for a range of utility investment decisions, as well as the development of future tariffs. While not directly taking on the task of identifying locational value for utility planning areas, the Order establishes the categories of value upon which successor tariffs to net metering are based. Further refinement of the detailed methodologies for calculating values was delegated to the utilities through the publication of specific BCA Handbooks.

5 The term "statewide" is used generally here. In practice, the DERAC tool accounts for the area of the Independent System Operator which accounts for over 80% of the state's load.
Modifying or Developing Tariffs

New York and California are examining tariffs where value varies over time and location. As part of its REV initiative, New York is now requiring that large commercial and industrial customers, and community solar customers, use the Value of Distributed Energy Resources tariff. California’s “Net Metering 2.0” tariff requires all net metering customers to take service on a time-of-use rate. Both moves are motivated by regulators’ intent for DER compensation to better reflect the locational and temporal value that distributed energy resources provide.

New York’s Value of Distributed Energy Resources (VDER) Tariff

In March 2017 and in subsequent Orders, the New York PSC approved a new compensation framework to replace net metering with value-based compensation for larger solar projects, including community solar projects. While maintaining net metering for residential customers through 2020, the VDER Orders establish compensation for electricity delivered to the grid on an hourly basis. They base compensation on categories of value making up a “value stack.” The components include: the actual value of the energy and capacity, the value of avoided environmental externalities, the value of avoided distribution system costs, the value of avoided distribution costs in specific locations, and a transition value that allows for a gradual shift away from retail rate net metering. But instead of using detailed utility analyses to determine locational value, which in many instances does not yet exist, the PSC approved the use of proxies to stand in for demand reduction and locational values until better methods can be developed. Successor VDER tariffs are expected to refine the way locational values are calculated and there is considerable debate by stakeholders over the proper methods.

California NEM 2.0 and a view towards NEM 3.0

Unlike New York’s “top down” approach of using proxies to inform new tariffs for DER, California has taken a “bottom up” approach to grid modernization. It has begun with new processes and methods for leveraging distribution system data for hosting capacity maps, modifying the distribution planning process, and determining locational value. The California Public Utilities Commission’s NEM 2.0 decision acknowledges this, stating that while the Commission recognizes that the full value of distributed PV is hard to quantify, the state’s grid modernization proceedings should continue to seek to better understand those values. The Commission determined the best course of action is to revisit net metering in 2019 after these proceedings have concluded. Currently the utilities and stakeholders are in the process of developing Locational Net Benefit Analyses for consideration by the Commission. Locational values are expected to be available in maps across the state with full locational values in mid-2019.

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9 California Public Utilities Commission, Decision D1601044 - Decision Adopting Successor to Net Energy Metering Tariff (January 28, 2016) pp.58-60. Available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf
PRINCIPLES FOR DEVELOPMENT AND USE OF LOCATIONAL VALUES IN COMPENSATION MECHANISMS

Locational valuation and compensation are emerging areas of utility regulation and DER compensation. Net metering, by contrast, is simple, easy for customers to understand, and is a proven, cost-effective way to achieve solar customer savings and provide benefits to all utility customers. SEIA and Vote Solar, together with numerous associations, environmental groups and clean energy advocates, has established net metering and rate design principles which guide SEIA’s view on the creation of locational values. SEIA is committed to developing accurate locational values that reflect the needs of the distribution system, identifying potential new revenue opportunities for DER projects from solicitations or new tariffs and programs, and working constructively in states that are considering modifications to net metering to incorporate locational value.

Based on our experience in these two jurisdictions, and building on our rate design and NEM principles, SEIA developed the following four principles for consideration with respect to the development and use of locational value for compensation.

1. Include the “full stack” of values of when designing compensation

Locational values have multiple components. First, there is the value in offsetting planned or potential investments in the distribution and subtransmission grid with less expensive DER options. Second, when properly authorized and wired, DER can help utilities and customers respond to localized system outages by providing power during times of interrupted service. Third, reduced electricity consumption also produces localized environmental and public health benefits and these benefits can be calculated and incorporated. Finally, there are values that DERs can provide for maintaining power quality, reducing line losses, and providing data to the utility for situational awareness.

Each of these locational values should be considered and rigorously analyzed when evaluating or developing compensation tariffs to capture the entire range of benefits that these resources provide. These values are additional to benefits that are system-wide (i.e., accrue evenly across the utility system), such as reduced need for powerplants, reduced greenhouse gases, and reduced high-voltage transmission. Both locational and system wide values should be considered together when using these values to evaluate DER programs or tariffs.

2. Ensure that locational values are long-term, stable, and financeable

As is done with utility investments, the locational value of DER should be structured to provide a consistent revenue stream over the life of the asset to ensure ease of financing. Utilities enjoy a regulatory structure that offers a return on- and return of- capital needed to make long-term investments. This proven mechanism has enabled utilities to confidently finance billions of dollars of assets and countless infrastructure improvements to meet the electric needs of society. Financial markets look kindly on this structure, which ultimately results in a lower cost of capital for the incumbent utility and lower costs for its customers. Distributed energy resource providers do not have such regulatory guarantees on their rate of return, but they should be afforded similar long-term financing treatment for the resources they deploy in lieu of utility-owned distribution equipment.

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Compensation tariffs to support DER investments must be structured to provide long-term revenue certainty to non-utility assets that are meeting utility customers’ needs. If this fails to happen, and compensation tariffs instead rely on short- or medium-term time horizons that don’t match the life of DER assets, the resulting tariffs will shortchange the value of the asset and make it difficult to arrange financing. When moving toward a more granular valuation of DER, regulators must ensure that the long-term value of the resource is recognized and properly included in compensation.

3. Ensure the reliability benefits of DER have value

Recent natural disasters have demonstrated the ability of solar coupled with battery storage to provide electricity service to individual buildings or groups of buildings. In California, however, the value of DERs to provide reliability has, to date, been viewed narrowly. In piloting solicitations of DERs to meet distribution needs, California has defined reliability as the ability to provide “back-tie” capability. Specifically, DERs can reduce load, effectively increasing the amount of incremental load that could be transferred through a tie line should another line face an outage. For resiliency, the utility’s LNBA demonstration projects considered the value of a micro-grid providing excess reserves for restoring customers and providing power within the microgrid during outages.

Looking forward, we expect that customer investments in stationary battery storage and other distributed energy resources (e.g., fuel cells) that can provide islanding capabilities from the grid and provide electricity service during outages will increase. This value should be incorporated into valuation and compensation frameworks moving forward.

4. Create opportunities for distributed grid services

Solar projects avoid generation, transmission, and distribution capacity projects that would otherwise have been needed. While locational valuation creates an opportunity to better understand this value to the distribution grid, there are new capabilities that DER can provide unrelated to avoiding capacity-driven projects such as substation upgrades needed to meet growing loads. Specifically, DER could help provide new grid services including situational awareness and voltage and power quality management.

Providing Utilities with More Data to Improve Distribution Grid Operations

Using smart inverters and other devices located at customer premises, third-party DER providers could provide data services for utilities that would otherwise install sensing and communications equipment. By leveraging existing DER assets, the utility will not need to invest in duplicative hardware. The data from these systems helps inform the utility about the operations of its distribution grid, an ability known as “situational awareness.”

Two important operational metrics are line voltage and line status (e.g. operating or experiencing an outage). In providing voltage and outage information, DER can provide functions similar to Advanced Metering Infrastructure, line sensors/fault detectors, and communication with line equipment, though DER can only provide the monitoring function and not the control function.

In addition to voltage, frequency, and the occurrence of an outage, DER can also provide loading information at each site to determine how much generation is being produced and used on site. By capturing and utilizing this information, utilities can use DER to help 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 resolved sooner, outages can be detected faster, modeling accuracy can be improved, and distribution state estimation could be implemented.

**Improving Power Quality and Reducing Electricity Losses Through Voltage Management**

As part of their core responsibilities, utilities must supply electricity to customers within established power quality standards. Because utilities do not always have visibility to the voltage on each line segment, they often raise line voltages at the substation to the upper end of the operating range to ensure customers at the end of the line are within acceptable standards. While this brute-force method keeps voltage within the required operating limits throughout the feeder, it also wastes electricity.

To address this waste from excess voltage, utilities are increasingly deploying conservation voltage reduction (CVR) programs. CVR is a demand reduction and energy efficiency technique that flattens voltage across a distribution circuit and allows the voltages to be lowered across the whole circuit. The impacts are significant: a 1% reduction in distribution service voltage can drive a 0.4% to 1% reduction in energy consumption.\(^{13}\) CVR programs typically save 0.5% to 4% of energy consumption on individual circuits, and are often implemented on a large portion of a utility’s distribution grid.\(^{14}\) Because distributed PV with smart inverters can increase or decrease the voltage at any individual customer location, these resources can be used to more granularly control customer voltages.

**CONCLUSION**

The modern grid must more effectively use DER such as solar to meet system needs. Increasingly, states leading the way in grid modernization are determining locational values and considering compensation mechanisms to guide DER to areas where they can have the most impact. Although these compensation mechanisms can take multiple forms, when designing any such mechanisms, regulators must incorporate the full range of values that DER brings to the system. Offsetting traditional capital investment, reducing demand in specific locations, and providing consistent power during periods of interruption are all values that should be captured when designing compensation methods for DER; these values are in addition to system-wide values such as the ability to avoid new power plants and high voltage transmission. Furthermore, regulators should design compensation based on a long-term time horizon, with an eye toward establishing stable DER revenue streams. By developing appropriate compensation mechanisms that will enable DERs to flourish, regulators, utilities, and customers can transform the electric grid into one that will better meet the needs of all customers.

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Celebrating its 43rd anniversary in 2017, the Solar Energy Industries Association is the national trade association of the U.S. solar energy industry, which now employs more than 260,000 Americans. Through advocacy and education, SEIA® is building a strong solar industry to power America. SEIA works with its 1,000 member companies to build jobs and diversity, champion the use of cost-competitive solar in America, remove market barriers and educate the public on the benefits of solar energy.