Comments on Behalf of the Solar Energy Industries Association and Illinois Solar Energy Association

1. 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 CCSA 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 broad collective knowledge and experience through participation 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, and doing so in a way that enables a market to develop in Illinois that can deliver these benefits.

1.1 Organization of Comments
The JSP appreciate the ICC’s efforts to facilitate the comment process by providing a detailed list of questions for party responses. The JSP have organized our responses in a somewhat different manner, but we have addressed many of these questions in our response.

As discussed in our prior comments and described in the revised version of the Pacific Northwest National Laboratory’s White Paper (“Revised White Paper”), we continue to believe that an iterative, evolutionary approach for determining DER value is necessary due to two overarching themes:

1. The evolution of DER technologies and the ability of utilities to integrate DERs into grid operations and planning, including the evolution of data availability and understanding of how to value and compensate DERs; and
2. The development of DER markets and businesses and the need for continuity and gradual, predictable changes in compensation levels and structures to enable the industry to scale up and reduce costs, including the near-term need for market certainty in the face of impending net metering caps.

Consequently, our comments are broken down into four main sections describing:
1. Evaluations of the methodologies employed in Minnesota and New York, the two examples described in detail in the Revised White Paper. These evaluations provide context for our recommendations in Illinois.

2. A brief discussion of incentive structures and considerations in translating value determinations into a rebate.

3. Near-term solutions to DER valuation, for use in circumstances where incomplete information or time constraints prevent a full evaluation of one or more value streams.

4. Long-term solutions that rely on a vetted, data-driven valuation methodology. These long-term solutions should remain iterative in nature, subject to refinement over time to improve their accuracy and granularity.

By “near-term” we refer to activities during the next 1-2 years, which involve establishing both an interim method of determining long-term DER value, and the methodology employed to translate that value into a rebate. By “long-term” we refer to continual activity that may take place over the next 5-10 years to validate, refine, and evolve valuation mechanisms. It is plausible that activities we define in the long-term path could begin in the 1-2 year timeframe (e.g., work to establish a firm scope and priorities) but any preliminary work of this type should be balanced with the higher priority of developing a near-term solution that ensures market stability and addresses the demands placed on stakeholders.

1.2 Summary of Key Themes
As Illinois continues to develop an approach to DER valuation it faces questions related to process and methodology. By process we refer to both the efforts to define a workable methodology, such as reaching agreement on data sources, assumptions, and modeling methods, as well as the individual steps and timelines for achieving this goal. In order to ensure that the process leads to reasonable outcomes, it is necessary to resolve several threshold issues up front. Letting these questions linger will frustrate future efforts. We identify four threshold issues and our associated recommendations below.

Valuation Requires Near- and Long-Term Tracks
We cannot emphasize enough how critical market certainty is for DER providers, or any industry for that matter. The uncertainty created by net metering caps, triggering a significant reduction in compensation for exports to the grid, presents a significant planning problem for DER providers. For some residential customers, that reduction could be up to 50% for the distribution and transmission components alone, and higher if volumetric charges for generation capacity currently contained in basic service rates are also excluded from the export credit. As discussed in our initial comments, the long and uncertain timelines associated with developing granular valuation methods and assembling the necessary data must be considered when planning the valuation process. We recommend that the process employ a near-term track to establish placeholder values, while a long-term track focuses on developing a granular methodology and refining it. We discuss possible near- and long-term approaches in more detail later in our comments.

Valuation Must Be Complete and Transparent
As shown by discussions in other DER valuation proceedings, the value of DERs is composed of a long list of individual components at different levels of the system, from generation to transmission to capacity to distribution. Energy value will be captured in electricity providers’ net metering programs pursuant to Section 16-107.5 of the Public Utilities Act—both before and after the 5% cap in Section 16-107.5(j) is hit. In terms of quantifying transmission, capacity, and distribution components, distribution level values have historically presented the greatest difficulty. Additional difficulties are present in Illinois because after the 5% cap is hit for an electricity provider pursuant to Section 16-107.5(j), capacity and generation value are excluded—despite the persistent value solar brings to all customers related to these costs.
Thus completeness has two aspects. First, methods for identifying the full suite of distribution values must be established. We address this full suite of values further in our comments on long-term approaches to DER valuation. Second, the exclusion of generally recognized values must be remedied. The simplest way to do so would be to incorporate any excluded values into the rebate calculation.

As discussed in our prior comments, it is critical that evaluation methods be transparent, both from the perspective of the models used and the underlying data. We urge the ICC to adopt a default policy that all models use be non-proprietary and fully accessible by all stakeholders, inclusive of the underlying data. Any confidentiality concerns should be addressed on a case-by-case basis, fully supported by legal justification under Illinois law (e.g., customer privacy), and any requests of this type should be accompanied by alternative proposals sufficient to ensure stakeholders have access to the information they need to meaningfully participate in the methodology development process.

**Zero-Values Are Not Appropriate Placeholders**
There is no rational basis for assuming that the magnitude of a given DER value stream is zero, either because of data insufficiencies or because the value is difficult to measure. Numerous DER value studies have identified non-zero values for various components, and while the magnitudes may differ for utilities in Illinois, they should be assumed to exist at some level. By contrast, a zero value is entirely arbitrary, more so, for instance, than the volumetric distribution rate, which is at least based on actual distribution costs.

**Smart Inverter Values are Incremental**
The Revised White Paper correctly identifies that references to the DER rebate as a “smart inverter rebate” are technically incorrect, since some potential rebate program participants will not have a smart inverter. Furthermore, Section 16-107.6(c)(1) specifies a default rebate level of $250/kW-DC for non-residential customers, which carries a condition that the utility is permitted to control the smart inverter during “distribution system reliability events.” As the JSP observed in our initial comments and the Revised White Paper observes, the statutory definition of DER value as it pertains to the rebate is broader, including “benefits to the grid” and “the value of distribution generation to the distribution system.” Collectively, these details dictate that smart inverter value, in the form of specific grid services and additional uses a smart inverter can provide, may be incremental to other DER values, including but not limited to distribution capacity deferral.

### 2. Review of Valuation Methodologies
The Revised White Paper summarizes the distribution value methodologies employed in New York and Minnesota as examples of potential approaches. While there are aspects of methods and processes used in both states that could be reasonable to replicate in Illinois, both suffer from several shortcomings, as discussed below.

#### 2.1 New York
The defining feature of New York’s Value of DER (“VDER”) framework thus far is that the New York Public Service Commission (“NYPSC”) adopted a transition to VDER for demand rate DER customers and community solar facilities without first establishing many critical details of how DER value would be determined. While it is true that the order establishing the transition to VDER contained directives (e.g., the use of marginal cost data), many details were left unspecified, to be addressed in utility implementation plans. In turn, significant constraints were placed on the development and review of

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actual calculations and data sources to be used because, having established an immediate transition to VDER, it was necessary to adopt calculation methods in short order. The NYPSC acknowledged that the calculation methods required further refinement in approving VDER implementation plans, but left those refinements to be made in a second phase.²

New York: Features That Could Replicated

**Dedicated Iterative Approach:** New York adopted an initial DER distribution valuation methodology in 2017, while also clearly stating its intent to follow an iterative, evolutionary approach. New York continues to refine its methods through a working group process.

**Use of Marginal Costs:** Avoided distribution costs, referred to as demand reduction value (“DRV”) on a system-wide basis and locational system relief value (“LSRV”) for locally differentiated value both use values derived from marginal cost studies. Marginal costs, as represented by a Marginal Cost of Service Study (“MCOSS”) are the proper measure of avoided capacity value, although we note there are several shortcomings on how the MCOSSs were conducted and used to establish VDER rates.

**Attention to Gradualism and Market Impacts:** While not part of the valuation mechanism per se, but critically important from a policy perspective, New York adopted measures to mitigate market disruption and smooth a transition to the VDER system. First, it delayed a transition to VDER for mass-market (i.e., non-demand rate customers) in the interest of gradualism.³ Second, it established a “Market Transition Credit” (“MTC”) for community solar facilities designed to smooth the transition from full retail rate crediting to the VDER system. The MTC mechanism is implemented under a declining capacity block system. The MTC reduces the effective decline in customer compensation by raising total compensation for subscribers to a given facility to a set percentage of the retail rate (e.g., 100% for Tranche 1, 95% for Tranche 2).⁴

New York: Shortcomings

**Incomplete Value Assessment:** The present Phase 1 methodology incorporates only avoided distribution capacity values. It does not value other distribution value streams that can be supplied by smart inverters, including voltage control and reactive power management, nor does it include reliability and resiliency services, enhanced grid visibility, reduced O&M, extended equipment lifetimes, the potential for reduced sizing of equipment replacements (another form of avoided capacity cost), or an avoided transmission capacity component.

**Inadequacies in the Use of Marginal Costs:** While we support the use of marginal costs in developing forward-looking values, the current system being used to develop VDER rates suffers from several shortcomings that limit its assessment of true long-term DER value, as follows:

- **Lack of Transparency and Consistency:** The different approaches used by utilities in New York for Phase 1 vary considerably. This variability extends from the MCOSSs on which the values are to some degree based to various utility-specific adjustments and assumptions in deriving avoided capacity costs from these studies (e.g., selecting only a subset of marginal costs, using different approaches to identify local value areas). The need to develop these values quickly due to the

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³ NY VDER Order, p. 86
⁴ Ibid, p. 129-130.
need to implement the new VDER system prevented a thorough review and evaluation of the differing methods.

- **Short-Term Perspective**: The marginal costs used to derive distribution value are effectively short-term costs rather than long-term costs that would be avoided over the lifetime of a DER, since they are reset every three years for the system-wide component. This places DERs at a disadvantage relative to traditional investments because in contrast to a DER investment, the costs and revenue from an equivalent utility investment are locked in for the lifetime of the equipment, not periodically reset.

- **Unpredictability**: Related to the short-term perspective, the three-year lock-in for DRV and 10-year lock-in for LSRV fail to provide the certainty needed to finance DERs, and as noted above, disadvantage DERs relative to the guaranteed revenue associated with utility investments that provide the same service. The energy component and capacity component are not fixed for any appreciable period of time, creating further uncertainty.

### 2.2 Minnesota

Minnesota’s law requiring the establishment of a value of solar (“VOS”) methodology specified a roughly eight month timeline for the framework to be developed, from the enactment of the associated legislation in May 2013 to the January 31, 2014 deadline for a proposal to the Minnesota Public Utilities Commission (“MPUC”). While the ultimate result of this process was reasonably complete taken as a whole, the distribution value calculation could be considered the least complete component, lacking many potential distribution values and resolution of issues associated with calculating localized values.

**Minnesota: Features That Could Be Replicated**

*Distribution Capacity Value Methodology*: The methodological approach used in Minnesota is not a true marginal cost study, but it could serve as a substitute if long-term marginal cost values cannot be obtained. The calculation could be considered to reflect inferred marginal costs based on historic trends in distribution capital investments.

*Long-Term Outlook For Distribution Value*: The VOS methodology develops an annual set of values for a 25-year period. Some cost components, such as generation capacity and transmission rely on values that are fixed over time, but the distribution value calculation uses an escalation factor. While the designation of the escalation factor itself is utility-determined and not entirely transparent, on a conceptual level the escalation factor is appropriate and reasonable because annual update filings show a substantial escalation in distribution project costs over time (e.g., roughly doubling from 2007 to 2016).

*Predictability*: The VOS rate is recalculated every year, but as applied to community solar projects the annually updated rates are “vintaged”, such that the 25-year rate schedule adopted in any given year is fixed for projects enrolled in that year. This feature provides critical certainty for DER providers and reflects the fact that avoiding a long-lived traditional investment avoids the cost of that investment for the life of a DER asset. The framework also uses an averaging system that dilutes the variations in capital expenditures that may occur from year to year, smoothing changes over time.

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6 MN Laws 2013, Chapter 85 (HF 729), Article 9, Section 10. [https://www.revisor.mn.gov/laws/2013/0/Session+Law/Chapter/85/](https://www.revisor.mn.gov/laws/2013/0/Session+Law/Chapter/85/)
Minnesota: Shortcomings

Incomplete Value Assessment: The distribution value assessment only includes deferrable distribution capacity investments. Thus far the methodology has not been refined to add voltage management, a component of smart inverter services which is necessary to define in Illinois, nor does it include a suite of other potential distribution values. Xcel’s application of the methodology to identify local distribution values, which first took place in its 2018 annual update filing, produced objections and resulted in an MPUC decision to convene a further stakeholder process.\(^8\)

Lack of Transparency: Though the methodology for calculating the value of solar rate is defined, the actual value of solar rate is updated annually in a utility compliance filing. Of central concern for the distribution value calculation is that it relies heavily on utility determinations of which distribution investment costs are capacity related, and the escalation of those costs over time. The methodology itself does not define the parameters for making these determinations and publicly available data shows only the results rather than how they were arrived at. These judgments have a powerful effect on the results. In some past years, more than 90% of distribution capital expenditures were excluded from the system-wide calculation as non-capacity related.\(^9\) Consequently, while 25-year “vintaging” is a critical feature of the Minnesota approach, transparency is lacking over what the values in future updates might be. This is concerning both from a business perspective (i.e., how to portray value when communicating with future customers) and from a public policy perspective (i.e., are the determinations made internally by utilities appropriate?)

Lack of Consistent Refinement Efforts: Though the initial adoption of the methodology indicated an expectation that it would be refined over time, a specific forum or mechanism to do so was never established. While some refinements have taken place, and a dedicated local distribution value stakeholder effort was established in 2018, discussion of improvements has largely been limited to the short comment periods afforded to stakeholders on the annual utility updates. Thus there is no systematic effort to identify and incorporate new values or otherwise evolve the model.

3. Incentive Structure
Section 16-107.6 specifies that the DER rebate be just that, a rebate. The term “rebate” is generally accepted to refer to an up-front incentive of the type contemplated by the initial non-residential rebate of $250/kW-DC. The JSP believe that Section 16-107.6 is entirely unambiguous in this respect, thus the incentive must be an up-front payment consistent with ability of a DER to address “present and future grid needs” as understood at the time of the rebate. Since a DER would be capable of addressing future grid needs over the course of its useful life, the rebate value must reflect value over the useful life of a DER. The JSP recommend a 25-year useful life, even though the JSP are aware of assets under contract for substantially longer.

In addition to the need to comply with clear directives provided by Section 16-107.6, the JSP observe that an up-front rebate based on long-term value at the time of installation would avoid the uncertainty created by ongoing payments subject to periodic adjustments to value-based compensation, such as in New York. A rebate approach also reflects the nature of avoided capital investments as “fixed” once they are avoided.


\(^9\) MN 2018 VOS Update. Table 14.
Further discussions are necessary to define exactly how an up-front rebate should be calculated based on the long-term value stream regardless of how that long-term value is calculated.

4. Short-Term Solutions Track and Proposal
Illinois law does not set the type of time-constrained deadlines for developing a DER valuation methodology that were present in equivalent efforts in New York and Minnesota. At the same time, more uncertainty is present in Illinois as to when the methodology will be needed because the timing of the 3% threshold in Section 16-107.6(c)—including how the 3% is calculated—is subject to uncertainty and potential dispute, and deployment rates under the Adjustable Block Program are unknown. Clarity is also lacking on the process for developing the methodology and how long it might take given unknowns about data availability and prioritization in determining the methods suitable to estimate different value streams. As discussed in our prior comments, the experiences in developing DER valuation methods in other states indicate that the time necessary to develop even a first generation methodology could be measured in years rather than months.

For that reason, we recommend that Illinois consider an alternative near-term approach. First we believe Illinois can follow New York’s model of recognizing and responding to the differences between mass market customers compared to community solar or demand rate customers. Illinois’ near-term approach can infer DER value as a simple percentage of applicable system costs and incorporate a market transition mechanism similar to the MTC in New York. The goal of this path is to establish an interim valuation mechanism that could be used, if necessary, to bridge the gap between an effective net metering “cliff” and the establishment of a more robust valuation regime, but most importantly to ensure a smooth transition to that new regime. While some complicating factors exist for creating such a mechanism, discussed further below, our recommended approach is simpler and features fewer unknowns than other options. It also has several precedents in other states facing similar obstacles to developing a value-based compensation regime.

4.1 Conceptual Model
At their core, existing rates for utility service are based on cost of service, though due to the nature of costing methods, an individual customer’s rates may depart from that customer’s “true” cost of service. The existence and magnitude of this departure is a matter of perspective because reasonable people can (and, in ICC dockets, frequently do) disagree on the most appropriate methods of cost allocation and rate design. That said, service rates are still an approximation of the actual costs to serve a given customer.  

For behind-the-meter residential customers in Commonwealth Edison (“ComEd”) territory, the compensation rate for exports to the grid could decline by 40-50% upon the triggering of the net metering cap due to the elimination of distribution and transmission charges from the calculation of the customer credit. This decline would be larger if the generation capacity component of generation supply charges, which is currently a volumetric charge in basic energy service tariffs, is also excluded from the export credit.  

For instance, ComEd’s volumetric charges currently total roughly $0.105/kWh, of which transmission and distribution comprise roughly $0.048/kWh (45%). Absent additional compensation for DER value, a customer with a 50:50 split between direct on-site use and exports would see a compensation reduction of 22.5% (i.e., 50% X 45%). The Revised White Paper shows agreement between the JSP and utilities that DERs have a non-zero distribution capacity deferral value. Therefore allowing

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10 In reality, all costing studies are only approximations however they are conducted.
11 Export compensation rate changes would be lower for customers paying demand-based rates for any of these components.
12 See ComEd rates statements here: https://www.comed.com/MyAccount/MyBillUsage/Pages/CurrentRatesTariffs.aspx
this value to descend to zero is inappropriate even if precise valuation cannot be completed. For instance, the most recent update of Xcel Energy’s VOS rate in Minnesota produced a combined system-wide transmission and distribution value of $0.0264/kWh (25-year levelized value). Likewise, as described in the Revised White Paper, New York has established distribution capacity deferral values based on marginal distribution costs.

The Revised White Paper does not discuss transmission value though it does include high-level information on how the Minnesota VOS methodology treats transmission value, which is based on tariffed transmission rates plus losses, adjusted for DER coincidence with peak transmission loading. Transmission capacity deferral, adjusted upward for losses, is a commonly included element in DER valuation studies. The initial version of the White Paper notes several additional state examples of this, including California and Oregon. Other recent examples include consultant reports commissioned by the Maryland Public Service Commission (“MDPSC”) and District of Columbia Office of the People’s Council (“DCOPC”).

Furthermore, this value is not just theoretical. For instance, in connection with its 2015-2016 transmission planning process, the California Independent Systems Operator (“CAISO”) credited rooftop solar along with energy efficiency with avoiding the need for nearly $200 million in transmission upgrades. In approving the 2017-2018 transmission plan the CAISO canceled 18 transmission projects and revised 21 other projects, avoiding an estimated $2.6 billion in future costs. The changes were mainly due to changes in local area load forecasts, and strongly influenced by energy efficiency programs and increasing levels of distributed solar generation. Likewise, the PJM incorporates DER solar forecasts into its Regional Transmission Expansion Plan (“RTEP”) through its load forecasting process, using a 15-year analytical timeframe. It is inescapable that DERs can, should, and do play a role in transmission planning by modifying load growth patterns, and consequently avoiding expenditures on transmission infrastructure that would otherwise be needed to serve local loads.

We recommend that an interim DER value be established using a percentage-based methodology, adjusted by a market transition mechanism based on the New York MTC. There are multiple ways that the interim DER value component could be calculated. One way would be to calculate the benefit as a percentage of the retail rate applicable to a given DER customer. Another way could be to calculate it based on the service level at which a DER is interconnected, such that a DER is assumed to avoid capacity at and upstream of the service level at which it is connected. The latter approach may be preferable because it would accommodate community solar facilities that have customers in multiple rate classes. Either way, the resultant value can then be modified by the MTC, and then translated into an upfront rebate using a series of assumptions (e.g., 25-year energy production, assumed rate escalation, etc.).

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13 MN 2018 VOS Update. Figure ES-1.
4.2 Practical Application of the Model
The setting of rebate amounts must consider the different needs and circumstances of residential, non-residential, and community solar DERs in the context of state policy goals and gradualism. As discussed in more detail later in our comments, interim mechanisms in other states are typified by effectively zero, or modest, changes to overall compensation experienced by DER customers while durable valuation mechanisms are being developed. We recommend New York as a general model for this purpose since it displays market segment differentiation in order to support continued growth in each segment. More specifically, the MTC mechanism is a reasonable way to balance a gradual transition to a value-based regime with increased maturity of individual market segments.

In practice, this could take the form of MTCs for each market segment that fill the difference between the needs of individual market segments and calculated DER values. As we describe further below, DER values not explicitly defined as “distribution” value and not reflected in other compensation require consideration as well. A well-designed MTC framework can be used to incorporate these components into an all-encompassing system. While we are describing this in the context of our near-term proposal, an MTC could endure in future iterations of the valuation system as a balance to the fact that even more granular valuation regimes will remain incomplete for some time.

The calculation could be made more elaborate by considering:

1. Varying the rebate by system orientation so that amounts vary for South-facing vs. West-facing systems based on likely peak contribution.
2. Coincidence with the range of peaks at different levels of the transmission and distribution system.
3. Methods of incentivizing participants to reduce or minimize exports.

As noted in the prior section, the translation of 25-year value to a rebate, regardless of how DER value is determined, requires further discussion.

4.3 “Triggers” Under the Model
As we have already described, uncertainty remains in the calculation of net metering penetration benchmarks, and the difference between pre- and post-cap compensation to customers is meaningfully different depending on customer segment. Residential and small commercial customers would experience the most significant changes. It is also uncertain what portion of those caps will be met by different customer segments. One reasonably foreseeable outcome is that the behind-the-meter residential and small commercial sectors, which experience the greatest negative impacts of an energy-only netting regime, end up comprising only a small portion of the overall NEM cap (e.g., 1% of the peak load calculation, equivalent to 20% of the 5% cap). At least 25% of the Adjustable Block program is directed toward 10 kW or less behind-the-meter systems, and such a shock could make meeting the statutory requirements for the Adjustable Block program substantially more difficult. Given the Illinois Power Agency’s (“IPA”) general approach to the Adjustable Block program—which currently assumes full retail net supply and delivery metering for customers with 10 kW behind-the-meter systems—a substantial reduction in net metering (or net metering replacement) revenues would cause a substantially similar cost increase for the REC contract.

The purpose of the MTC is to moderate changes in total compensation along a glide path to a value-based compensation regime, which in our conceptual model, is individualized by market segment. We propose, in order to avoid unexpected, sudden, and substantial changes that may endanger systems procured pursuant to the Adjustable Block program and consumer expectations, that the starting value of a segmented MTC is the amount necessary to bring total compensation to 100% of pre-5% cap net metering value. For the residential sector on non-time of use rates, for instance, such a value would be full retail
supply and delivery (excluding energy), while for non-residential customers it would replace the $250/kW smart inverter rebate and the difference between 16-107.5(e) or (f) net metering and energy netting. The question then becomes what level of DER penetration within a given segment triggers a reduction in the MTC, so as to reduce total customer compensation below pre-5% trigger value. We propose that non-demand rate, behind-the-meter DER customers not experience such a reduction in total compensation until they achieve a designated percentage of net metering penetration for their specific rate class or the IPA’s initial allocation of under 10 kW behind-the-meter systems have been successfully placed under contract. This would preserve equity and diversity in the opportunities afforded to different DER sectors.

4.4 Role of Customer Charges in Distribution Cost Recovery
It is the JSP’s understanding that Illinois has historically used an embedded cost approach—allocating a percentage of distribution revenue to a class of customers and creating rates meant to recover those costs—rather than defining charges based on a delineation between customer-specific distribution costs and shared distribution costs. This practice bears relevance to the interim value method we describe above insofar as the current retail distribution rates are not designed to fully segregate the costs of shared distribution facilities from direct customer costs (e.g., service drops). This is another reason why an approach derived from costs at individual service levels rather than a rates-based approach could be preferable. In other words, distribution rates themselves do not reflect full distribution costs because a portion of shared distribution costs are recovered via customer charges.

To be clear, are not suggesting that the development of a DER valuation methodology address distribution cost allocation or retail rate design. However, it is an issue to consider in the context of our interim proposal because existing rate designs already modify (i.e., reduce) the connection between distribution rates that can be offset by DERs, and full, shared distribution system costs. This figures into what portion of a rebate is considered part of DER value, and what portion could be considered part of an MTC.

4.5 Inclusion of Other DER Value Streams
We have included transmission value in our interim valuation proposal and believe it should also be considered part of the rebate calculation in our long-term solution proposal described in a subsequent section for several reasons:

1. Section 16-107.6 specifies that the rebate investigation include “calculations for valuing distributed energy resource benefits to the grid”. The transmission system is an integral part of “the grid”.
   a. In fact, the Commission has held that transmission is part of distribution: “As explained by ComEd, the reference to ‘electricity produced’ plainly refers to the tangible quantity of electricity produced by the project – no mention is made of any services, whether transmission services or volumetric non-distribution services. Indeed, Section 16-102 of the PUA classifies transmission as a delivery service – not a supply service. 220 ILCS 5/16-102.” (ICC Docket No. 17-0350, Final Order dated September 27, 2017 at 15 (emphasis added).)
   b. Even though transmission is assessed on the electricity supplier and not the distribution utility (unless the utility is also the supplier), the Commission’s holding demonstrates that at minimum reducing transmission costs is a “benefit to the grid” if not “value of the distributed generation to the distribution system.”
2. Section 16-107.6 also specifies that rebates “reflect the value of the distributed generation to the distribution system at the location at which it is interconnected.” The transmission system is part of the system of wires used to distribute or deliver electricity and transmission costs vary by location due to both embedded costs and congestion. Furthermore, there is no bright-line test for determining whether a given line is classified as transmission or distribution. Utility
classifications based on voltage vary and some utilities define a further sub-class of delivery infrastructure as “sub-transmission”.

3. It is undeniable that at a minimum, DERs reduce losses on the transmission system by providing physical supply locally that need not be provided via the transmission system. Interconnection regulations prevent individual DERs or aggregate groups of DERs from backfeeding power through a substation to the transmission system, meaning that no energy from DERs will ever reach the transmission system. Furthermore, DERs produce immediate, tangible operational benefits beyond even the deferral of transmission capacity expansion by reducing local transmission loading and congestion.

The inclusion of transmission in the DER valuation regime is supported by the spirit and intent of Section 16-107.6 with respect to properly assigning value to DERs, and is also consistent with the language despite the lack of an express reference.

Generation capacity is a further DER value stream that is not expressly referenced in Section 16-107.6 as components of the rebate. As stated in our initial comments, the JSP believe that the Legislature’s intent was to establish mechanisms that provide compensation for the full set of DER value streams—especially as net metering required in Sections 16-107.5(d), (d-5), (e), (f), and (l) reverts to “energy netting” after the 5% cap from 16-107.5(j) is hit. Generation capacity, inclusive of capacity reserve margin, is consistently part of DER valuation efforts in other jurisdictions, including the New York and Minnesota examples described in the Revised White Paper. This inclusion is typically not controversial. To the extent that compensation for these values is not already accurately reflected in other forms of compensation, they should be included in the rebate calculation and consideration of the MTC.19

4.6 Alignment Illinois Law
Section 16-107.6 requires that the rebate reflect geographic, time-based, and performance-based benefits of DERs. The interim valuation determination that we recommend can be made consistent with all of these features:

Geographic: Geographic differentiation would be reflected by establishing separate rebate amounts for different utility service territories.

Time-Based: The time-based benefits of DERs could be reflected by considering system orientation and other factors that affect the solar generation profile and how it contributes towards serving peak loads.

Performance-Based: System production estimates could be individualized for each rebate recipient through the use of a standardized estimation model. This approach has been used in the past for a number of programs in other states, typically referred to as an Expected Performance-Based Buydown (“EPBB”) incentive model. Performance, in terms of incentivizing on-site consumption over grid exports, could also be reflected in different ways so as to encourage behavioral changes or incentivize storage.

4.7 State Precedents

Key Themes
Various states have pursued their own investigations of net metering in the last several years and ultimately failed to resolve the interconnected and complicated set of issues associated with adapting DER compensation methods to provide value-based signals. In most of these cases regulators had more

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19 We observe here that demand-based charges in general, whether for generation capacity, transmission, or distribution, do not fully value DERs because they do not accommodate the “negative demand” provided by exports. This negative demand has value equal to load reduction.
flexibility to devise “alternative” regimes than is present in Illinois insofar as they had the full discretion to choose any model they saw fit. By contrast, Illinois law currently specifies a firm end to net metering (beyond energy netting) rather than an alternative model, and requires value-based compensation to take the form of a rebate. Despite these differences, the methods employed in other states point to a consistent strategy for addressing possible disconnects between DER compensation and DER value.

Several decisions of this type have adopted systems similar to the interim near-term model we propose, where either the monthly credit for exports or the credit for gross exports is reduced by a small amount to address concerns that the value of DER energy production is less than the volumetric retail rate, in some cases focused only on transmission and distribution. In several of these states, Arizona, New Hampshire, and Utah, regulators continue to pursue longer-term initiatives to further define DER value streams and reliable methods for calculating DER value.

We wish to emphasize here that we are not recommending any of the specific approaches described below. Instead we point to what they show as a collective whole, that when faced with significant unknowns, policymakers have chosen interim methods characterized by moderation, to wit, very modest (or no) reductions in compensation while further investigation takes place.

Thus while we describe a number of examples of state-level decisions exhibiting moderation in the following sub-section, we emphasize that even small changes can have long-lasting, disruptive impacts, the more so when they are unpredictable or sudden. Because these decreases in valuation in states mentioned below are still new, we recommend the ICC complete an analysis of practical impacts these reductions are having on customer choice and investment.

Examples

**Arizona**: Arizona’s DER export tariff sets compensation for residential and small commercial customers for exports to the grid at a less than retail rate, based currently on a Resource Comparison Proxy (“RCP”) that reflects the costs of historic utility-scale solar energy purchases. This rate is updated annually but may not decline by more than 10% per year. This proxy method is to be used until a value-based export compensation methodology can be finally established. While this model is indicative of some level of moderation, the annual reductions are arbitrary from the perspective of both DER value (i.e., DER value is not necessarily related to utility-scale PPA pricing and timing) and the more so when they are unpredictable or sudden. Because these decreases in valuation in states mentioned below are still new, we recommend the ICC complete an analysis of practical impacts these reductions are having on customer choice and investment.

**Maine**: Maine established a revised netting system with an annually declining percentage of “nettable energy” for the transmission and distribution portion of a customer’s bill. Beginning in 2018 this percentage is 90% and then declines by 10% increments during the next 10 years. DER customers lock in the applicable annual percentage for 15 years.

**Nevada**: Nevada adopted an alternative net metering regime for systems 25 kW or smaller through 2017 legislation. Like many incentive programs, new net metering system uses a capacity tranche (80 MW) system that progressively reduces the carryover rate for monthly excess generation from the full retail rate

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20 The JSP understand that some electricity providers may hit the 5% cap in Section 16-107.5(j) before others, and electricity providers may hit that 5% cap before or after the 3% or 5% trigger in Section 16-107.6.
to 95% for the first tranche, 88% for the second tranche, 81% for the third tranche, and 75% for all new installations after the third tranche is filled.\textsuperscript{23}

\textit{New Hampshire:} New Hampshire’s Alternative Net Metering regime reduces the rate at which distribution charges are credited on a monthly basis to 25\% of the volumetric distribution rate. In other words, rather than a kWh credit that effectively includes all volumetric delivery charges (i.e., distribution at 100\%), the customer receives a monetary credit composed of the sum of 25\% of the distribution rate and 100\% of other volumetric rate components. Stakeholder work on devising the parameters for a DER value study is ongoing.\textsuperscript{24}

\textit{New York:} As we have previously described, New York’s transition to the VDER model retained traditional net metering with compensation for exports at the full retail rate for mass-market customers (i.e., non-demand) customers. In doing so the associated order recognized that “[m]aturation of this market segment and appropriate business models will require notice and a more gradual evolution to a new compensation methodology.”\textsuperscript{25} Furthermore, New York established the MTC for community solar facilities to smooth the transition from full retail rate crediting to the VDER system, implemented using a declining capacity block system. The MTC reduces the effective decline in customer compensation by raising total compensation for subscribers to a given facility to a set percentage of the retail rate (e.g., 100\% for Tranche 1, 95\% for Tranche 2).\textsuperscript{26}

\textit{Utah:} Utah’s net metering transition program reduces compensation for all exports to the grid (as measured in 15-minute intervals) to 90\% of the average energy rate for residential customers and 92.5\% of the average energy rate for non-residential customers. The program is capped at 170 MW for residential systems and 70 MW for all other systems. A new proceeding will be convened in the future to establish a durable export credit rate.\textsuperscript{27}

4.8 Smart Inverter Compensation

The interim calculation method described above is not intended to be inclusive of grid services and additional uses that smart inverters provide. Smart inverter functions, such as the Volt-Watt, Frequency-Watt, and Volt-VAR with reactive power priority functions provide incremental system value beyond values such as distribution capacity deferral and avoided distribution losses that DERs not equipped with smart inverters can provide. The activation of these smart inverter functions represents a tradeoff for a DER customer, a reduction in the ability to produce real power for the customer’s own use in exchange for compensation for the value that foregone real power production has to the grid. In other words, a DER customer is forgoing their exclusive right to benefits of the system to allow it to be operated for the benefit of all customers. This type of shared usage is incremental and must be compensated beyond the rebate compensating eligible customers whose DERs are not equipped with smart inverters.

The JSP provided a fuller discussion of the grid services and additional uses that smart inverters provide in testimony submitted in Docket Nos. 18-0537 and 18-0753 relating to ComEd’s and Ameren’s interim DER rebate applications. Please see the footnoted links below to view the testimony from the Ameren.


\textsuperscript{25} NY VDER Order. p. 86.

\textsuperscript{26} Ibid. p. 129-130.

proceeding, which provides a more complete picture of the nuances associated with smart inverter grid services, additional uses, and compensation.\textsuperscript{28}

\section*{5. Long-Term Solutions Track and Proposal}

The JSP expect that developing a robust DER valuation methodology will take at least several years based on experiences in other jurisdictions. We anticipate that devising even a reasonably complete first generation model could take in excess of two years given the need to collect multiple years of data to validate models, DER performance, etc. In practice, efforts to develop and refine methodologies could span years beyond that. For instance, New York’s Value Stack Working Group was formed in June 2017 for developing improvements to the VDER model. This group already possessed marginal cost studies and methods that were subject to at least some prior review and comment, but has yet to fully develop even an initial set of refinements.\textsuperscript{29} As described in our initial comments, this effort would be best accomplished through a working group process with mandates and defined deliverables. In the following subsections we re-iterate several characteristics that should govern this process and elaborate on core distribution value components, prioritization of certain aspects, and related matters.

\subsection*{5.1 Importance of Process and Transparency}

A stakeholder driven methodology development process will not function well or produce good results without a clearly defined mission and transparency-oriented attitude. We discussed how this process could operate at some length in our initial comments and will not repeat all of those recommendations here. However, we do wish to re-emphasize the need for two key features:

1. Quasi-informal, outside of a potentially constraining regulatory process, but with a clear core set of objectives and defined deliverables.
2. An emphasis on full transparency of any models developed for use in determining values and the accompanying data.

The need for transparency cannot be emphasized enough. Despite the years long stakeholder process to develop locational value models and tools, integrate DERs into distribution planning, and devise methods for securing DERs to defer distribution upgrades in California, progress has recently been frustrated by efforts to hold significant and impactful information confidential and potentially exclude some stakeholders (i.e., DER providers) from critical steps in the distribution planning review process. Illinois would benefit from tackling this issue at the outset of stakeholder proceedings, and the JSP recommend that the “default” policy should be full transparency and participation absent a legal justification for confidentiality or exclusion.

\subsection*{5.2 Core Value Components, Data Needs, and Priorities}

At a high-level, the JSP believe that valuation efforts should be prioritized based on a combination of likely magnitude of different value streams, ease of development, and Illinois’ statutory requirements. Collectively we identify the following first priority items that demand prompt attention.

\textit{Determine Market Segment Differentiation:} Our near-term proposal would establish differential treatment by market segment and contemplates that an MTC mechanism could continue to exist in later phases of

\textsuperscript{28} ICC. Docket No. 18-0537. Direct Testimony of the JSP Parts 1 and 2. 

\textsuperscript{29} See NYPSC Matter No. 17-01276 to view the history and proceedings of the Value Stack Working Group. 
the transition to a value-based regime. It will be establish when and how different customer segments transition to more granular value-based regimes at the outset of the long-term process so that transition mechanisms can be known in advance and DER providers can adapt to them. For instance, the transition path will almost certainly influence how DER providers plan for offering energy storage in concert with generation DERs, depending on how the attributes of energy storage are reflected in the valuation regime (see below).

Develop and Vet Marginal Cost Studies or a Substitute: Marginal costs are the proper measure of avoidable costs. Since Illinois' utilities do not conduct marginal cost studies currently as part of formula rate updates or revenue-neutral allocation proceedings, it could be challenging to develop a marginal cost valuation model in the near term. If it turns out not to be possible to do so in a reasonable time frame, efforts should focus on:

1. Working to establish the parameters for future marginal cost studies and how they will be used to develop DER values.
2. Devising a substitute method and the parameters surrounding its use. The Minnesota VOS method could serve for this purpose, but we emphasize that Illinois should go beyond what Minnesota has done to introduce further standards defining how cost escalation is done and how costs are classified as deferrable or not deferrable. Further discussion should also include the historic timeframe used to establish first year capacity costs, as well as a more general and detailed review of the overall methodology.

Focus on System Level: The initial focus should be on establishing methods for determining value at the system level and validating the approach. This would satisfy the statutory requirement for geographic differentiation without over-complicating the effort (i.e., crawl before walking).

Focus on Distribution and Transmission Capacity Deferral Value: Developing these values has precedent in other jurisdictions and both are likely to be significant value streams based on results in other value studies. While the finer details of the methods need to be reviewed, as noted above the Minnesota VOS methodology could serve as a starting point. This effort should include the definition of line loss values that become incorporated into capacity deferral values, adjusted from any average line loss factors to reflect higher marginal line losses during peak periods.

Establish Smart Inverter Valuation Mechanisms: Because smart inverter operation is a key component of the DER rebate program and participation will require activation of smart inverter features for many customers, making progress on this valuation aspect is important. We anticipate that this could be challenging because smart inverters are themselves relatively new technology and equipment and operational standards have not yet been fully defined.

Determine How Energy Storage is Valued: Energy storage has value potential distinct from distributed “generation” and is increasingly becoming part of the DER landscape. There are a multitude of different use cases for energy storage, ranging from islandable back-up power to load modification to operating as a multi-directional grid asset, or a combination of uses. Longer-term valuation mechanisms must consider how different use cases should be reflected either within the calculation of the rebate, or incrementally outside of it as an additional source of grid value/services.

Define Additional Value Streams: While it may be necessary to defer the calculation of some value streams to a future phase, it is a first priority task to identify additional value components and devise for how they will be studied in later phases, and take the preliminary steps that will make this possible. As described in the JSP’s initial comments, additional distribution value streams that should be discussed in this context include:
1. Reduced O&M;
2. Extended equipment lifetimes;
3. Reduced sizing for equipment replacements; and
4. Enhanced awareness and grid visibility.

6. Conclusion
The JSP appreciate the opportunity to participate in the process of establishing mechanisms for unlocking the value of DERs and the methodologies associated with determining DER value. At this early stage we focus our comments as much on process as methodology because timing uncertainties and constraints and public policy issues are equally important to the more technical aspects determining DER value. Our proposal would establish a broad framework under which Illinois could pursue a transition to a value-based regime of DER compensation while also recognizing and responding to the reality that developing the finer details of such a regime and creating an environment that allows different DER market segments to grow into this regime will take time.