AEE INSTITUTE

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VIA ELECTRONIC FILING

Hon. Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Empire State Plaza, Agency Building 3
Albany, New York 12223-1350

Re: Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources

Dear Secretary Burgess:

The Advanced Energy Economy Institute (AEEI), on behalf of Advanced Energy Economy (AEE), the Alliance for Clean Energy New York (ACE NY), the Northeast Clean Energy Council (NECEC), and their joint and respective member companies, submit for filing these comments to the *Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering,* in the above-referenced proceeding.

Respectfully Submitted,

Ryan Katofsky
Senior Director, Industry Analysis

Response to "Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference" (Case 15-E-0751)

Advanced Energy Economy Institute
Alliance for Clean Energy New York
Northeast Clean Energy Council

Preface

The mission of Advanced Energy Economy Institute (AEEI), the charitable and educational organization affiliated with Advanced Energy Economy (AEE), is to raise awareness of the public benefits and opportunities of advanced energy. As such, AEEI applauds the New York Commission for opening this proceeding on Reforming the Energy Vision (REV), which seeks to unlock the value of advanced energy so as to meet important state policy objectives and empower customers to make informed choices on energy use, for their own benefit and to help meet these policy objectives.

In order to participate generally in the REV proceeding and respond specifically to the *Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering* (the "Notice"), issued on December 23, 2015, in Case 15-E-0751 - In the Matter of the Value of Distributed Energy Resources, AEEI is working with AEE and two of its state/regional partners, the Alliance for Clean Energy New York (ACE NY) and the Northeast Clean Energy Council (NECEC), and the three organizations' joint and respective member companies to craft the comments below. These organizations and companies are referred to collectively as the "advanced energy community," "advanced energy companies," "we," or "our."

AEE is a national business association representing leaders in the advanced energy industry. AEE supports a broad portfolio of technologies, products and services that enhances U.S. competiveness and economic growth through an efficient, high-performing energy system that is clean, secure and affordable. ACE NY's mission is to promote the use of clean, renewable electricity technologies and energy efficiency in New York State, in order to increase energy diversity and security, boost economic development, improve public health, and reduce air pollution. NECEC is a regional non-profit organization representing clean energy companies and entrepreneurs throughout New England and the Northeast. Its mission is to create a world-class clean energy hub in the Northeast delivering global impact with economic, energy and environmental solutions.

Executive Summary

The advanced energy community strongly supports the efforts of the Commission in this proceeding, and is committed to playing its part to create a high-performing electricity system in New York State. To that end, we look forward to our continued involvement in this proceeding, and in assisting the Commission in this endeavor. In this section we provide a brief summary of our proposal on DER compensation. Our detailed comments follow below.

Our proposal is to develop hourly "LMP+D" prices for the applicable distributed energy resource (DER) customers, retroactively calculated at bill settlement, employed for both consumption and distributed generation (DG), so that all forms of DER are treated equally. For DG, bill crediting would remain the mechanism for compensating production. Although settlement for billing purposes is done retroactively, appropriate price signals would be sent ahead of time in order for DER owners/operators to make decisions on how to operate ("dispatch") their assets. Data and analysis tools would also be made available and kept up-to-date so that customers and third parties could develop and refine pricing models and analyze different DER options for use with the LMP+D rate. This will help ensure that investment continues to flow into New York's DER market.

The proposed LMP+D rate would be similar to a real-time rate in that it would incorporate hourly energy prices, but it would also allocate capacity, line loss effects, and other costs as functions of hourly load and would reflect locational differences. It would also include all other benefits, such as environmental externalities, as outlined in the Commission's BCA Framework Order.[1] In short, "LMP+D" includes all wholesale market values and the full value of DER to the distribution system, including externalities, including those that may need to be approximated at this time. The result is location-specific hourly pricing with a much higher differential between on-peak pricing and off-peak pricing than exists with current time-of-use (TOU) rates, which average costs over large service territories and predefined TOU temporal periods.

The LMP+D rate would apply to certain customers with distributed generation (DG) technologies or load modification schemes, including dispatchable resources (such as fuel cells, demand response and electricity storage) and non-dispatchable resources (such as solar photovoltaics). However, dispatchable resources could be controlled to provide enhanced economic benefits by delivering energy or reducing consumption at times when prices are highest. Through the implementation of this rate, DER would be preferentially installed in locations of highest value and operated at times of highest value, but this would not limit any customer's ability to install DER.

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[1] "Order Establishing the Benefit Cost Analysis Framework," January 21, 2016, Case 14-M-0101, State of New York Public Service Commission.

Consistent with the Commission's principle of gradualism, as clearly articulated in the Track 2 White Paper,[2] the LMP+D rate would be implemented gradually, and its use expanded as it is demonstrated to be effective at driving DER deployment and delivering on the expected benefits. We expect our LPM+D proposal to be implemented in parallel with continued availability of retail rate net energy metering for eligible technologies up to the net metering caps, in accordance with statute. This will avoid disruptions to the market as LMP+D is implemented. Our proposal also includes a set of applicability criteria that determine what types of DER projects and DER customers would fall under the new LMP+D rate or would remain on existing retail rates. Our proposal also preserves retail net energy metering as the default option for some customers, even after aggregate net metering caps have been met, although any customer could opt into the LMP+D rate. Eventually, our proposal sets LMP+D as the default rate for some DER customers, after a suitable transition period. This approach will create opportunities for early movers to test new rate designs and will also help balance the costs of initial implementation prior to more widespread deployment of advanced metering functionality needed to make hourly pricing widely available to customers.

Although our proposal is based around hourly prices, we also propose several methods for managing the higher expected price variability that will result. This is important to DER providers in financing projects and in developing attractive value propositions for customers – the LMP+D rate must be implemented in a manner that supports DER project finance and drives customer adoption of DER. Our objective with the interim proposal is to provide adequate certainty and clear price signals such that customers and DER providers can begin to deploy DER in a manner consistent with the overall objectives of REV. The proposal seeks to strike a balance between technical accuracy, practicality, and understandability for customers. Over time, we expect that further refinements to hourly pricing and increased functionality on the distribution system will allow for even better alignment between electricity pricing and costs, which may eventually include sub-hourly pricing where this makes sense (for example, with the full-valuation methodology).

This proposal ensures that utilities will be able to recover prudent infrastructure costs at a fair rate of return, empowers them to invest in ongoing improvements for both the collection and delivery of distributed energy, compensates them for their services in facilitating transactions between DER suppliers and their customers, and provides a mechanism for them to invest in future infrastructure as needed to meet existing reliability standards and to achieve REV objectives.

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[2] "Staff White Paper on Ratemaking and Utility Business Models," July 28, 2015, Case 14-M-0101, Department of Public Service.

At the same time, the price signals that follow from this proposal will enable DER providers and energy services suppliers, including home and building energy management technology providers, to take advantage of new business opportunities. These companies will be able to respond to the new price signals by developing alternatives to conventional utility solutions. The LMP+D rate will ensure that they receive fair compensation for delivered energy, capacity and other grid and societal benefits through non-discriminatory access to the distribution grid. Customers will enjoy new choices in both supply-side and demand-side alternatives, will be able to reduce their electric bills, will continue to be able to make sustainable energy choices through either on-site or remote distributed generation, and will be able to make informed energy decisions that benefit both them and the State of New York.

Details of the LMP+D rate calculation methodology are provided in this proposal and its Appendix. The methodology is based on the categories defined by the Commission through its BCA Framework Order and employs the methods described in that Order. For example, our proposed methodology uses ICAP costs as the key input to the avoided generation capacity cost, in agreement with the Order. However, it then takes these costs and allocates them to each hour of the billing period using a prescribed calculation method.

Importantly, the viability of the conceptual framework proposed here, and the decision to adopt it, are subject to the ability of the utility, acting as the "Distributed System Platform" (DSP) provider, to develop and make available the cost and technical data required for calculating the LMP+D rate. It also depends on the deployment of interval metering for LMP+D customers. We do not offer a quantitative analysis at this time, but instead focus on the approach and methodology, with the assumption that there will be an opportunity to undertake a full analysis of the LMP+D rate later in this proceeding.

We believe that our proposed approach to LMP+D is responsive to the clearly stated objectives of the Commission to incent DER deployment that is beneficial to participating customers, non-participating customers, the electricity system as a whole, and society. We believe it represents a meaningful evolution from the current system of DER compensation.

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1. Introduction

On December 23, 2015, the New York Public Service Commission ("Commission") issued its *Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference* (the "Notice") under Case 15-E-0751. The Notice posed a number of questions related to the development of interim and full-value methodologies of distributed energy resource (DER) compensation that could be used as a successor to net energy metering (NEM). The Notice also anticipated the adoption of a BCA Framework, which was executed in the Commission's *Order Establishing the Benefit Cost Analysis Framework* ("BCA Framework Order") on January 21, 2016.

This proposal is offered by AEEI, ACE NY and NECEC in consultation with Clean Power Research.[3] It is intended to address the questions posed by the Commission in the Notice and incorporate the BCA Framework Order.

2. Guiding Principles for DER Compensation

The REV Track 2 White Paper emphasized the principle of gradualism, even as it put forward bold proposals for reforming utility revenue models and rate design. REV also has at its core the goal of fully valuing DER, as the Commission has stated in various orders and other documents. We believe that the principles described below are consistent with the principle of gradualism and the objective of fully valuing DER, as well as other REV objectives and established ratemaking principles.

Commitment to REV principles. REV goals have a significant public benefit focus, as affirmed by the Commission in its BCA Framework Order in which the Commission adopted the Societal Cost Test as the primary metric of cost effectiveness. As such, for REV to be successful, DER that helps meet REV goals should be compensated for its full value and contribution to societal objectives. The LMP+D rate should encompass the full value to the wholesale market, which can extend beyond NYISO's location-based marginal price (LBMP) to include, for example, capacity and ancillary services. Thus, the "value of D" represents the "full range of additional values provided by the distribution-level resource."[4]

Smooth transitions. As we move from the current NEM regime to the interim LMP+D compensation methodology and eventually to the final compensation methodology, transitions must be smooth and predictable so that there are no disruptions in the development of the market or to customers.

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[3] Clean Power Research is a software and consulting company based in Napa, California, engaged by AEEI to assist in the development of this response.
[4] Notice, p. 2.

DER providers and consumers alike will be committing significant capital and other resources to deploying DER in New York State, and they need to have reasonable assurances that the rewards are commensurate with the risks. Similarly, in order for capital to be available on reasonable terms, DER compensation mechanisms and levels will need to have a sufficient degree of predictability and certainty. This does not necessarily mean that revenue needs to be fixed over extended periods of time, but that it be predictable enough to enable capital to be raised on reasonable terms, and for DER providers to develop offerings that present customers with attractive value propositions.

Consistent with the Commission's principle of gradualism, as clearly articulated in the Track 2 White Paper, the LMP+D rate would be implemented gradually, and its use expanded as it is demonstrated to be effective at driving DER deployment and delivering on the expected benefits.

We also recommend that the "value stack" defined in the interim and final methodologies should be similar and there should not be a sudden change in the value given to DER when transitioning from one to the other. What will likely differ are (i) how contribution to value is determined and (ii) the refinement of estimates of certain values that are only possible to quantify precisely with the final methodology, as metering, monitoring, communication, and control capabilities are improved. Nevertheless, as we have articulated in previous comments on the BCA Framework, just because it may be difficult to calculate a precise value for a particular benefit does not mean that its value is zero. Rather, there is a range of acceptable practices that can be use to approximate a benefit until more precise methods are available.

Honoring existing projects and contracts (**this addresses Question A.3**). Customers and third-party DER product and service providers have already committed significant capital and developed business models around existing DER compensation schemes that rely on net energy metering at the retail rate ("retail rate NEM"). As such, existing projects should be "grandfathered" to remain on current compensation methods and rate structures (i.e., net metering with existing retail rate structures) for the duration of the project life, consistent with the intention of New York's net metering statute. Requiring customers to transition to a new compensation mechanism before the project end-of-life undermines customer and developer confidence for both current and future investments. However, consistent with the Track 2 White Paper, these customers should also be able to opt-in to a new compensation model if they choose to become "active" customers. We provide more details below on specific grandfathering terms.

Equal treatment of all forms of DER. The advanced energy industry represents a wide range of technologies and services. These technologies are often complementary to one another and deployment of a range of DER solutions will increase the benefits from REV. Currently in New York, different types of

DER are treated differently, e.g., some types of DG receive full retail rate NEM whereas others do not, and different technologies have different per-project capacity limits to qualify for NEM. Under our proposed compensation mechanism, we believe that, to the greatest extent possible, future DER projects should be compensated for the value each provides under the same basic framework, and that existing limitations that are technology or project-size specific be phased out, absent a compelling demonstration that such differentiation is appropriate, provided this is consistent with existing net metering statute.

Right to Self-Supply. Customers should have the option to meet their own energy needs in a manner in which they see fit, including the ability to self-supply. As REV is implemented, we envision an electricity system where there are fewer limitations placed on the ability to self-supply based on aggregate caps, DG system size and technology type. We believe that our LMP+D proposal helps move us towards that desired end state.

Accurate Price Signals. Our proposal is intended to result in a set of pricing signals that more accurately reflects the value of generation and delivery of electricity to customers and the other benefits defined in the BCA Framework Order. Pricing is developed with sufficient granularity so as to enable DERs to provide services where and when they are needed most, to enhance the overall efficiency of the developing DSP markets, and to increase the options available to suppliers and consumers. The pricing is locational, and this will result in the installation of DERs where they are most needed. The pricing is also temporal, and this will result in resources that effectively deliver energy and capacity when they are needed most. To be most effective, this pricing should reflect the long-term value of DER to the system, as recognized by Staff in the Notice (at page 3).

We believe that the temporal aspects of pricing are not as well understood as the locational differences. Differentiating the price at time intervals of an hour will, we believe, result in attractive new enabling opportunities for DER that do not currently exist. To take but one example, the economics of bulk energy storage (i.e., storage not necessarily related to ancillary services) are driven by two factors: (1) the price differential between charging and discharging and (2) the shape or "sharpness" of the peak (with sharp peaks, less energy must be stored to achieve the same peak reduction effect, and this can be done at lower capital cost by installing a smaller battery). By transitioning to more granular time interval pricing (e.g., as opposed to current TOU pricing), both of these factors are improved. Although additional data and analysis are required to more fully evaluate the quantitative impacts, dispatchable technologies – such as distributed storage, demand response and fuel cells – could be more cost-effective. Under hourly pricing, prices during the lowest load hours would be lower than averaged off-peak TOU prices, and prices for the highest load hours would be higher than averaged on-peak TOU prices. As a result, DER technologies could more cost-effectively respond to time-differentiated pricing. Furthering the example of storage, charging costs will be lower and discharging credits would be higher. The pricing peaks would be shorter than broad TOU periods. Both of these factors help to enable storage and other DER technology options simply by exposing the actual costs in higher temporal resolution.

Ensuring Ability to Export Power. Under the proposal, any LMP+D customer would be able to export energy and receive compensation based on the calculated hourly price. The proposal simplifies the treatment of behind-the-meter (BTM) generation in that the benefit to the customer is aligned with the benefit to the grid: the same customer benefit is realized whether the energy is self-consumed or whether it passes through the meter. This will also ensure that projects can be sized to best meet the needs of customers, if that means that they are exporting power at certain times.

Flexible Meter Configurations and Aggregation Strategies. The proposed LMP+D rates are applicable to both generation and consumption. The same rates can be employed in BTM configurations and to separately-metered resources, such as shared resources. This approach simplifies the rules for ownership and aggregation. As a consequence, DER resources will be developed based on cost and technical factors related to the delivery of high-value services.

Utilities should be able to recover prudent infrastructure costs. Our proposal is based on the premise that the utility will continue to make infrastructure investments, consistent with the Track 1 Framework Order, needed to ensure safe and reliable operation of the grid, but that non-utility-owned DER will be used to offset the need for some of these investments. Future capacity needs (load growth and replacement capacity) will be met by both the utility investment and by non-utility-owned DER. The utility, as the DSP provider, will continue to manage the system in such a way as to incorporate these DER investments into its planning and operations. To the extent that the utility continues to invest required capital, it should be allowed to recover its costs plus its established rate of return (subject to the changes expected in the Track 2 Order). However, to the extent that third-party-owned or customer-owned DER serves this purpose, future utility investments will be reduced and the utility will be responsible for collecting revenues from customers to pay the DER providers for the services they deliver. We believe that the Track 2 Order will address the specifics of this, such that utilities will be incented to pursue DER options.

3. Challenges

Time-differentiated Metering

With about 28,000 MW of cumulative solar capacity in the United States,[5] solar is a popular DER technology that has been studied extensively over many years. Many solar valuation studies and methodologies have been developed in New York and other jurisdictions,[6] and these could be adapted to conform to the BCA Framework Order. It would be possible to use this approach to develop a mechanism that leads to a fair LMP+D compensation rate for solar. Such a method, however, could not be extended beyond solar and applied to the broad range of DER technologies. The method employed in solar valuation studies takes advantage of the deterministic nature of solar, that is, the fact that hourly solar production can be readily estimated and computed from historical solar irradiance and other meteorological parameters.

An essential step of those studies has been to develop a historical hourly production profile that represents the solar resource.[7] By combining this production profile with historical hourly location-based marginal prices (LBMPs), historical hourly loads, and other factors and assumptions, it is possible to derive energy, capacity, and other values and establish compensation rates that can be applied to metered production (i.e., dollar compensation per kWh of production).[8]

In particular, the hourly production profile can be used to deterministically derive the "effective capacity" of the resource,[9] depending on its correlation with peak loads. Once the effective capacity is determined analytically, basic watt-hour meters can then be used to measure output. Despite the fact that these meters do not measure time-differentiated output, such as with TOU meters or interval meters, capacity-related benefits can still be included in the compensation rate because the effective capacity per kWh has already been estimated and incorporated into the compensation rate.

The problem with using the above approach for an LMP+D rate is that it cannot be extended to non-solar, dispatchable technologies. This is because it is not possible to pre-determine corresponding

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[5] http://www.seia.org/research-resources/solar-industry-data

[6] There is, for example, a detailed methodology provided in the "Maine Distributed Solar Valuation Study," developed by Clean Power Research for the Maine Public Utilities Commission, April 2015, available at http://www.maine.gov/mpuc/electricity/elect_generation/valueofsolar.shtml

[7] In some cases, multiple profiles are developed to represent scenarios based on design orientation (e.g., west-facing systems versus south-facing systems versus tracking systems) or based on customer classes (e.g., commercial versus residential) or location (e.g., based on the resource differentiated by utility service territory).

[8] These rates may also be developed under different frameworks, such as current year rates or long-term levelized rates, depending upon policy objective.

[9] A number of such definitions of effective capacity have been used in solar valuation studies. These include the average output during the top N peak load hours and the rating of an equivalent baseload resource resulting in the same loss-of-load probability as the solar resource. Effective capacities are often referred to as the "effective load carrying capability (ELCC)."

production profiles and calculate effective capacity for these technologies, as these technologies would be dispatched by the DER operator (e.g., a third-party or the customer with on-site DER). With the operator in control of the resource, and not the utility or grid operator, the production profile would not be deterministic, and historical dispatch patterns may not reflect current or future dispatch patterns.

This does not mean that these technologies do not have capacity value. Quite the opposite is true. Dispatchable technologies, like fuel cells, could be dispatched by the grid operator and credited the same way wholesale generators are credited at full nameplate rating (after adjusting for forced outage rates). However, our proposal seeks instead a method to provide the credit at the retail level, through rates, without central dispatch and without the need to enter into contractual obligations with NYISO.

To achieve this objective, our proposal is that DERs seeking to receive payment for performance receive such payment based on actual time-differentiated production or load modification to determine the *ex post* benefit. In this case, the actual production during peak hours would determine the DER's contribution to peak load reduction. To continue the fuel cell example, by operating during the hours when it is of greatest value to the electricity system, the fuel cell owner would receive payments at the highest prices corresponding to those hours. If the owner decided not to operate during those peak hours (or to operate at partial capacity), the full potential electricity system benefits would not be realized. Still, the DER owner would be compensated based on the actual contribution to system need – as represented by the LMP+D price – made in those hours.

Availability of Interval Meters

The implementation of LMP+D, therefore, rests upon the ability to measure time-differentiated production and consumption. In the fuel cell example above, interval meters were assumed where energy measurements would be stored, transmitted to the meter data manager (likely the utility or DSP provider), and used for billing computations in hourly intervals.[10]

TOU meters could also be considered, but as discussed earlier, these do not provide the same temporal resolution as interval meters. As an example, consider a 10 kWh residential battery system. Suppose further that the peak NYISO load hour for the year occurs on August 3, during the hour ending 4:00 pm, that the output of the battery system was 7.5 kWh during the peak hour, and that the total Super-Peak (2 to 6 pm) energy discharged for the billing month was 100 kWh. How would the peak output be determined?

[10] Eventually, shorter intervals could also be used, such as 15-minutes. These could be consolidated to obtain hourly intervals. Alternatively, LMP+D rates could be developed for shorter intervals, but our interim proposal assumes hourly intervals for simplicity.

- Interval meter: Hourly output from 3:00 pm to 4:00 pm on August 3, is measured directly as 7.5 kWh (or 7.5 kWh/1 hour = 7.5 kW average power output over the hour).
- TOU meter: Monthly Super-Peak generation is 100 kWh. Peak output is 100 kWh / 80 super-peak hours per month = 1.25 kW average power output over the August Super-Peak hours.

In this example, the interval meter was able to measure the battery output during the peak hour directly, but the TOU meter could only measure its average output over the TOU period (in this case 80 hours), diluting the measured effectiveness of this resource from 7.5 kW to 1.25 kW. The same result of 1.25 kW could have been observed if the battery were discharged during each of the four-hour Super-Peak periods at a constant output of 1.25 kW. While the measured result of this constant output scenario would be the same as the previous scenario, it clearly would not provide the same system benefits. Therefore, TOU meters can only be used as a coarse measure of time-dependent benefits.

Advanced metering infrastructure (AMI) has the ability to meter production and consumption in hourly, or more granular, intervals as described above, and could therefore be employed in the LMP+D implementation. However, AMI meters are not yet available throughout New York. ConEdison recently received Commission approval to roll out AMI to its customers in the 2017-2022 timeframe, after selecting vendors, working through design issues, developing the communications and IT systems, etc.[11] This timing presents a challenge in implementing LMP+D today and suggests a natural divide between the "interim" and "full value" methodologies sought by the Commission. Other utilities do not have specific AMI proposals approved by the Commission, and as such, may not have these capabilities for some time. So, the timing to move to the final DER compensation methodology may vary by utility.

The interim methodology must, at a minimum, be based on existing metering as installed or available to utility customers in New York. Interval meters are available and used in New York by some customers (such as ConEdison customers under Rider M),[12] and these could be used to implement time-varying LMP+D rates. TOU meters could also be used, but these would be much less desirable due to the diluting effect described above.

Note also that measured non-coincident customer demand (available using demand-meters) does not enter into our proposed pricing mechanism. Non-coincident demand is the peak demand for the

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[11] "Advanced Metering Infrastructure Business Plan," October 15, 2015, available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B075E822D-4286-4A63-9AD5-E3BC36B95D21%7D

[12] See Leaf 214, "Rider M – Day Ahead Hourly Pricing," available at: http://www.coned.com/documents/elecPSC10/GR24.pdf

individual customer over the billing period, and this peak is measured at a time that does not generally correspond with either the hour of the distribution peak or the NYISO system peak. Therefore, these demand meters do not accurately reflect cost causation[13] and do not adequately encourage the use of DER for system benefit.

Our proposal assumes that AMI is not available for use with the interim methodology, but will be available in the full valuation methodology. The interim methodology is designed to work with interval meters, using cellular data and public networks to transmit the data. We also assume that a customer will have the option of selecting a utility-qualified interval meter prior to AMI rollout. Our interim proposal could also work with TOU rates but that is not our preferred approach. The Commission could consider a parallel TOU option, but we would not support a TOU-only option.

Note that this interim solution means that some DER technologies may not be able to realize their full potential benefits without upgraded meters. For example, energy storage providers understand that standard watt-hour meters provide no time differentiation at all, and that the TOU price averaging discussed above may not result in an adequate price differential.[14] These providers may therefore find more opportunity with customers who already have interval meters installed, such as larger industrial customers, or in cases where the project economics support the installation of an interval meter. Once AMI is broadly available, then hourly pricing would be available for even the smallest residential customers, and the opportunities for DER to provide their full potential value would be found in greater abundance. Opportunities to aggregate customers would also develop.

The availability of hourly LMP+D rates in advance of AMI therefore creates a dilemma in which the benefits of DER may be limited by the availability of adequate meters. Our interim solution is to install interval meters, though the additional costs have to be considered. Since our interim proposal will help validate core objectives of REV, we propose that the Commission adopt a policy that allows LMP+D metering costs to be rate-based during the interim period. Alternatively, the customer or third-party provider could be asked to pay a portion of the metering cost if a future AMI rollout is near enough to prevent the interim metering solution from passing a cost-effectiveness screen. This would allow, say, commercial and residential customers to install interval meters at little or no cost to them. These customers would then be able to take advantage of time-differentiated pricing and DER technologies could be installed under a technology-neutral environment.

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[13] Electronic meters that measure both time-differentiated energy and demand would be usable, but the demand measurements would not be needed.

[14] Storage could still be used, however, for back-up power applications and could participate in wholesale markets directly.

Alternatively, third-party DER providers, including solar installation and leasing companies, typically install and maintain their own remote monitoring and metering capabilities that use existing internet connectivity and other telecommunication networks. Sometimes, these systems also monitor total BTM electricity consumption and not just DG system output. These systems can provide revenue-grade metering as they are often used for tracking solar renewable energy credit (SREC) production. If such metering offers a more cost-effective solution during the interim period to provide for hourly time-differentiated pricing, at least with some DER options, it could be used instead of installing an interval meter.

4. Applicability of DER Compensation Options Under the Proposed Methodology

Before we address the specifics of the LMP+D interim and final compensation mechanisms, we present here our proposed applicability of different compensation mechanisms for different categories of DER. (This section thus addresses **Question A.12**).

General Considerations

Our proposal is based on the following general considerations:

- Applicability does not differ based on whether the interim or final LMP+D methodology is being used, although in some cases there may be a transition period depending on specific metering or other technical requirements to enable the LMP+D rate.
- In the interest of simplicity, equity, and consistency with current net metering law, our proposed approach includes continuation of retail rate NEM as the default option for certain types of DER as part of the overall LMP+D proposal.
- Our approach is, by design, as neutral as possible with respect to DER technology type or project size. As a practical matter, in some cases it may be necessary to delineate or restrict applicability based on technology or project size, but it is our general assertion that as the DSP is established and the distribution system gains increasing flexibility and intelligence, issues related to technology type and project size will be less important than other DER characteristics.

Rationale for continued use of retail rate NEM with certain customers

The success of REV depends on a sufficient number of customers becoming more engaged with their energy use and deploying DER that benefits not just themselves but the system as a whole – so called "active" customers, to use the terminology of the Track 2 White Paper. This can be in response to specific DSP solicitations to meet system needs, or by taking advantage of new DSP capabilities to integrate DER and using compensation options via rates designed to elicit desired customer behavior.

Nevertheless, not all customers need to be engaged in this manner, and in fact, there will at some point be diminishing returns from incremental active customer participation in DSP markets. As such, active participation in DSP markets should not be a necessary criterion for DER deployment going forward and, moreover, customers should be able to adopt DER in a manner that best meets their own needs. Even if distribution grid benefits may be smaller from such deployments, they still further several REV and state clean energy goals. For these "passive" mass-market customers, as articulated in the Track 2 White Paper, retail rate net metering, with bill crediting as the compensation mechanism, should remain available even after the final LMP+D methodology is in place, subject to the ability of the grid to accommodate the DER.[15] Moreover, as stated in the Notice (at page 3), in the Track 2 White Paper, Staff recommended that changes to NEM should be focused on larger projects with substantial net export of electricity. As described below, our proposal is consistent with this approach.

Further, the Public Service Law section 66(j) and 66(l) provide net metering for a variety of technologies and project sizes, up to a cap established by the Commission. At this time, the cap is 'floating' above the previously established level of 6% of 2005 peak demand. Without statutory changes, the Commission would still reserve the right to modify this cap level. In utility areas where even the 6% cap has not been met, we assume that retail net metering would still be available for eligible technologies up to the cap, in accordance with statute. Distributed wind has a separate cap set at 0.3% of 2005 peak demand; we similarly assume that consistency with the statute would require the availability of retail net metering for distributed wind until that cap has been met.

In short, the rationale for continued use of retail net metering for certain customers is both the provision of appropriate market signals to passive customers, as well as to comply with net metering statute.

[15] Track Two White Paper, p. 108; also referenced in Notice, p. 3.

Detailed Applicability Criteria

Table 1 summarizes our proposal for DER compensation eligibility. Each category is described in detail below:

1. Existing NEM Systems

Existing NEM systems are operating systems that currently receive NEM under existing state statute and regulations, including BTM DG, Community DG (CDG) and remote net metering (RNM) systems, or that will be placed into service under current NEM rules prior to the implementation of the interim LMP+D rate. For the purposes of this proposal, "placed into service under current NEM rules" includes projects that are interconnected, are under an interconnection contract, or have paid for their Coordinated Electric System Interconnection Review (CESIR) within six months after the Commission issues its final order establishing the valuation of the LMP+D rate. Under our proposal, all such systems would continue to qualify for full retail rate NEM for the life of the project up to 25 years from the date that the LMP+D compensation mechanism is put into place.[16] Grandfathering will enable those systems to continue to operate for the life of the asset under the same financial conditions that existed when investment decisions were made. Importantly, this treatment will reassure customers, DER providers, and the investment community that New York State policy will continue to honor private contracts made under rules that were in effect at the time these decisions were made. Our expectation is also that the utility will maintain rates and service classifications that are primarily based on volumetric rates and otherwise are, at least structurally, similar to today's rates for which customers using NEM are eligible. Once an LMP+D compensation mechanism is in place, existing NEM customers could opt into that rate if they saw benefit, e.g., if they wanted to start to actively manage their DER assets. After 25 years, if a project is still in operation and receiving retail-rate NEM, it will be treated as a "new" project and would receive compensation based on which of the categories below it falls into.

For CDG projects, grandfathering should apply to the entire project – if a CDG project experiences customer turnover, new customers will receive the project's grandfathered rate.

[16] 25 years is consistent with the Commission's recent order on grandfathering of remote net metering projects in Case 14-E-0151.

2. Future Behind-the-Meter DG that currently qualifies for NEM

These are DG projects that meet the current criteria for NEM under existing state statute and regulations but that are placed into service after the new compensation mechanism is put in place. We delineate these systems into two categories:

- **NET IMPORTERS:** Systems that are, by design, sized primarily for meeting local consumption. These systems may export power from time to time and carry forward NEM credits over some billing cycles, but over the course of a year are net importers of electricity. The initial design of the system would be the basis for the designation of these systems as "net importers". For these systems, we propose that retail rate NEM continue to be the default rate option, with an opt-in provision to LMP+D for "active" customers, as described in the Track 2 White Paper.
- **NET EXPORTERS:** Systems that are, by design, sized such that they are usually net exporters of electricity on an annual basis, but are neither CDG nor RNM projects. For these systems, we propose that LMP+D become the default rate, after a suitable transition period that would be used to validate the viability of applying the LMP+D rate to these projects. During the transition period, customers could choose either existing NEM crediting with existing retail rates, or crediting using the LMP+D rate. As above, the initial design of the system would be the basis for the designation of these systems as "net exporters". To avoid the situation where projects in the net-importer category may be viewed as falling into this net-exporter category, we propose that the criterion be that annual production must exceed 120% of annual consumption, measured on a three-year rolling average, for a system to fall into this category.[17] This will avoid the situation where, for example, a home that is normally a net importer, but is unoccupied for an extended of period of time, will not be unfairly moved into this net-exporter category. Similarly, the reverse is possible if circumstances change such that a net exporting system becomes a net importing system (e.g., if an electric vehicle is added to the home's load). If on a three-year rolling average basis, that customer becomes a net importer, they would have the option to move into the net-importer category.

For net-importing systems not on the LMP+D rate, the Commission will need to address issues related to payments made by the utility for net excess generation (NEG), if there is any such excess on an annual basis. Although customers should be allowed to carry forward credits from year to year, should

[17] This is consistent with Staff's statement in the Notice (at page 3) that "changes to NEM should be focused on larger projects with substantial net export of electricity."

they desire to receive payment, we propose that customers receive monetary compensation based on the LMP+D rate. Because these customers may not have interval meters, the per-kWh value would be based in some way on the LMP+D methodology and rate, recognizing that the value of the exported energy is higher than just the avoided energy but may be less than the full LMP+D rate. We recommend that the Commission set this rate as part of the establishment of the interim methodology. Assuming that the number of DG systems (and associated annual NEG) that fall into this category will be small, taking an administratively simple approach to setting the rate is justified over a employing a complex formulation. As with current NEM rules, the customer may make a one-time election as to when to do the true-up.

For the net-exporter category, the customer would also carry forward credits from month to month, but should have the option of receiving monthly payments from the DSP for any credits associated with NEG, at the LMP+D rate. They could also elect for an annual payment (if one exists), also at the LMP+D rate.

For the net exporter category, we also envision an important role for aggregators and third-party DER providers. Aside from managing the development and operation of those projects for maximum customer and system benefit, third parties could act as intermediaries for the financial aspects as well, which could facilitate the business and tax implications of such projects. Third-party DER providers (e.g., solar leasing companies, demand response companies) already provide similar services and have their own DER monitoring and control capabilities. This would also simplify matters from the DSP perspective by allowing them to deal with a smaller number of entities for interconnection and settlement purposes.

As described above, retail-rate NEM would continue for all project types eligible under law until caps established by the Commission are met. For distributed wind, for example, the cap has not been met anywhere in New York State, so retail-rate NEM would continue. Similarly, ConEdison and Rochester Gas and Electric both appear to have DG deployment (connected) less than one-quarter of the 6% cap.[18] As such, consistency with the statute would require the provision of retail net metering until that cap is achieved.

3. Behind-the-Meter DG without Export Capability

While this may not be a common situation, it is still worth including "behind-the-meter DG without export capability" in the overall proposal. For example, these systems may work well within networked systems in the downtown districts of smaller cities, such as Schenectady, where back-feeding into the grid may not be possible due to the network design. Although we expect the DSPs to build out

[18] See for example, see recent utility reports filed in Case 13-00205 - In the Matter of SIR Inventory, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=41907.

capabilities that will facilitate the interconnection of DG within networked systems, doing so may take time. In the interim, such systems would include technologies designed to mitigate export such as charging a battery from solar or pre-heating water and would be sized such that the load always exceeded the generation, or include technology to prevent export using system controls and operational strategies (and thusly be listed as "qualified technologies" by DSPs), or they could have an electro-mechanical relay that prevents export.

For these systems, export is not applicable, and the default compensation rate would simply be the applicable retail rate. But as with NEM systems, customers would be able to opt into the LMP+D rate.

4. Community Distributed Generation

Community DG systems currently represent a source of significant potential growth in New York, particularly community solar. The Commission has rightly recognized that CDG represents an important opportunity for customers who cannot install BTM DG, and its continued availability to customers will support important REV goals, such as resource diversity, customer empowerment and emissions reductions. Also, as these projects are often larger than most BTM installations, there is the potential that CDG projects can achieve REV goals and provide support for utility distribution systems at an overall lower cost. CDG projects are also good candidates for installing interval metering and adding intelligent control capabilities prior to full AMI rollout because the size and relatively small number of projects would more easily justify the added expense for such metering and control. At the same time, a rapid build-out of CDG projects could create integration challenges and, in the near term, shift a portion of the utility's revenue requirement from participating customers to non-participating customers. Given these conflicting issues, we propose the following:

- For CDG projects that target low and moderate income (LMI) customers, or that are located in opportunity zones, participating customers should continue to receive full retail-rate NEM crediting, consistent with the CDG Order.[19]
- All other CDG projects would be compensated at the LMP+D rate as the default rate if they fall outside the grandfathering criteria described above under "Existing NEM Systems". The

[19] CASE 15-E-0082 - Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program. *Order Establishing a Community Distributed Generation Program and Making Other Findings*, Issued and Effective: July 17, 2015.

monetary value of the credits would be based on the location of the project and applied to subscribing customers' bills based on their share of the project output.

This describes the overall compensation rates applicable to CDG projects. However, as with BTM systems that are net exporters, there is an important role for aggregators and third-party DER providers, acting as the CDG owner/operator, to simplify the customer experience with CDG projects. Specifically, we propose that in the case where a CDG project is receiving LMP+D compensation, that the project host would have the option of electing to allow each subscriber to receive full retail-rate NEM crediting from the utility for their portion of the output from the CDG project. Any difference between this customer credit and the value of LMP+D compensation would be paid to the utility by the CDG project owner in the form of a fee. This ensures that, to the customer, the transaction is identical to third-party-owned BTM DG and current CDG rules. The third party/CDG owner would incorporate the monetary effects of any such fee into their payment plans with their customers (the CDG subscribers). Importantly, this fee paid to the utility by the CDG project owner may also be a credit from the utility to the CDG owner, if the value of the output, calculated under LMP+D, is greater than the retail rate credits being received by subscribers.

Since the value of this CDG owner fee/credit will vary over time, it may negatively impact the ability to obtain financing. As such, we strongly recommend that the Commission consider ways to provide greater certainty. For example, the Commission could phase in the fee over a period of time. Below, in our detailed responses to Question 1 and Question 10, we provide several additional options that the Commission could consider to address this issue for CDG projects and LMP+D projects more generally.

5. Remote Net Metered Systems

We recognize that from the utility's perspective, a RNM system may look similar to a CDG project or some BTM projects that are net-exporters. As such, we propose that LMP+D become the default rate for RNM systems under the new compensation mechanism, after a suitable transition period that would be used to validate the viability of applying the LMP+D rate to RNM projects. During the transition period, customers could choose either volumetric crediting with existing retail rates, or monetary crediting using the LMP+D rate. For RNM projects receiving the LMP+D rate, the value of the credit would be calculated using the LMP+D rate that is applicable where the project is located. Monetary credits would be applied to the bill(s) of one or more other locations with the same owner, whether the other sites used the LMP+D rate or the conventional retail rate.

This proposal would apply to new projects not subject to the grandfathering provisions described above under "Existing NEM Systems". As described above, projects would be grandfathered to receive full retail-rate NEM if they are already receiving retail rate NEM, or if they are at a sufficiently advanced stage of development, at the time the LMP+D compensation mechanism is put into place, or if they have been grandfathered under existing Commission orders, as is the case with RNM projects receiving monetary credits as specified in a series of recent Commission orders.[20] If so, such projects would continue to receive that compensation over the life of the project, for up to 25 years from the date the LMP+D compensation is put in place.

Similar to CDG projects, a developer or third-party could transact the LMP+D value with the utility, plus a tolling fee/credit, while the utility credits the RNM customer at the full retail rate.

6. Other Behind-the-Meter DER (non DG)

All of the categories above apply to distributed generation.[21] But for REV to be successful, other forms of DER should also be able to participate in DSP markets, such as demand-side strategies and technologies, including energy efficiency, energy storage (not coupled to DG), demand response and electric vehicles. For these technologies, traditional retail-rate NEM does not apply because there is no onsite generation. Rather, as the default, customers with these technologies would just remain on the applicable retail rate. But as with DG eligible for NEM, customers employing any of these DER technologies could also opt into the LMP+D rate. We further propose that customers with energy storage where energy export is anticipated would default to the LMP+D rate after a suitable transition period. As discussed above, the system benefits of energy storage and other demand-side management (DSM) technologies that can be used to actively manage load can best be realized with time-varying rates.

To ensure that all distributed energy resources are valued adequately, such that customers and DER providers are able to put forward least-cost distribution alternatives to the benefit of all consumers, the inherent differences between energy efficiency and other forms of DER need to be addressed. Indeed, as a form of DER, energy efficiency can provide additional value in certain locations. For example, the ConEdison BQDM program uses energy efficiency to reduce load and peak demand in a specific location.

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[20] *Order Raising Net Metering Minimum Caps, Requiring Tariff Revisions, Making Other Findings, And Establishing Further Procedures*, Issued and Effective: December 15, 2014; *Order Granting Rehearing in Part, Establishing Transition Plan, and Making Other Findings*, Issued and Effective April 17, 2015. CASE 14-E-0151 - Petition of Hudson Valley Clean Energy, Inc. for an Increase to the Net Metering Minimum Limitation at Central Hudson Gas & Electric Corporation. CASE 14-E-0422 – Petition of Solar Energy Industries Association, Alliance for Clean Energy New York, the Vote Solar Initiative, the National Resources Defense Council and The Alliance for Solar Choice to Clarify the Process for Utilities to Seek Relief from Net Metering Caps..

[21] The above categories could also include DG coupled with energy storage.

To realize the additional value that energy efficiency provides in certain locations on the grid, we propose that customers remaining on the traditional retail rate be eligible to receive a locational adder to be applied in locations where energy efficiency is determined by the DSP, in coordination with the NYISO, to provide additional value to the distribution or transmission grid. The utility would receive the adder and pass some of it along to implementers and/or customers, depending on the procurement model.

This adder could be used to drive additional energy efficiency deployment, improved marketing campaigns, or new procurement approaches deployed for energy efficiency and demand response. Additionally, we recommend that the locational adder be tied to savings performance to drive deeper savings projects. For example, the locational adder could be proportional to performance, weighted to be larger for higher savings achieved by a portfolio of projects (segmented by sector) in that location.

An alternative mechanism could be a distribution locational credit. Where energy efficiency is determined to be more valuable to address a constraint in the grid or some other reason, projects in that location earn a bill credit for the consumer to reflect that value.

7. All other DER

This category includes the following:

- BTM DG that does not currently qualify for NEM, RNM or Community DG, either because it is a technology that is not covered or because the project size is outside of current NEM rules
- All DER that is connected in front of the meter, either on the customer premises or on the distribution system (including DG and energy storage)
- Community microgrids

For these projects, there are no preset size limits. Although there could be technical constraints on project size as a function of the hosting capacity of the grid at the point of interconnection, the application of size limits is otherwise arbitrary. For these projects the default compensation rate would be LMP+D, although it is also possible that the DSP or another third party would contract directly with the project owner for services that would be specified in a bilateral contract. This should be permitted and, for example, could be in response to an RFP from the DSP or because the scale of the project justifies such an arrangement.

Table 1: Summary of Eligibility for different DER compensation mechanisms

DER Type	DER Characteristics	Standard retail rate (See note 1)	Retail rate NEM (See note 1)	LMP+D
Existing NEM systems	Any existing DG that currently qualifies for NEM, including Community DG and Remote Net Metering	n/a	Grandfathered tariff and rate structure for life of the project, or up to 25 years	Opt in, if becomes an “active” customer
Future BTM DG that currently qualifies for NEM **(See note 2)**	Sized by design for meeting local consumption (exports “from time to time” but usually a net importer on annual basis)	n/a	Default	Opt in, for “active” customers
	Sized by design to be a net exporter on annual basis (but does not qualify for RNM or Community DG) Production must exceed 120% of load on a rolling three-year basis	n/a	Default until the applicable net metering cap is met or transition period ends.	Opt in until net metering cap is met or transition period ends. Default thereafter.
BTM DG without export capabilities	Any size	Default	n/a	Opt in
Community DG	LMI and opportunity zones	n/a	Default	Opt in (must be for entire project)
	All other projects	n/a	n/a	Default Alternatively, customer receives retail rate NEM credit, but project developer/sponsor pays “tolling fee” or receives credit for the difference between the retail rate and the LMP+D rate.

DER Type	DER Characteristics	Standard retail rate (See note 1)	Retail rate NEM (See note 1)	LMP+D
Remote net metered systems	Any DG that currently qualifies for RNM	n/a	Default for grandfathered projects and new projects during transition period	Opt in for grandfathered projects and new projects during transition period Default for all other projects after transition period
Other BTM DER (non DG)	EE, storage not paired with solar, DR, EVs	Default where no export anticipated Locational adder for EE	n/a	Opt in where no export anticipated Default where export is anticipated, after suitable transition period
All Other DER	• DG that does not currently qualify for NEM, RNM or Community DG • Non-BTM DER (incl. storage) • Community microgrids • No size limits, but interconnected to the distribution system	n/a	n/a	Default (Could also contract directly with utility for services)

Notes to table:

1. The “standard retail rate” and “retail rate NEM” would have the same structure and value, with the latter referring to DER that qualifies for net metering and that has suitable metering technology installed.
2. We propose that these categories continue even after current net metering caps are met. Retail rate NEM customers with net excess generation at the end of a year can cash out at the LMP+D rate. Customers can make a one-time election as to when to do the true-up.

General Notes:

- In general “LMP+D” refers to both the interim methodology and final methodology, and assumes the availability of suitable metering technology to implement the LMP+D rate.

5. Proposal for Interim Methodologies

Q1. Interim Proposal

Identify and describe, in as much detail as possible, a mechanism or mechanisms to more precisely value DER as bridge, as currently effectuated in tariff today, while the complete value of D tool and methodologies are developed.

Overview

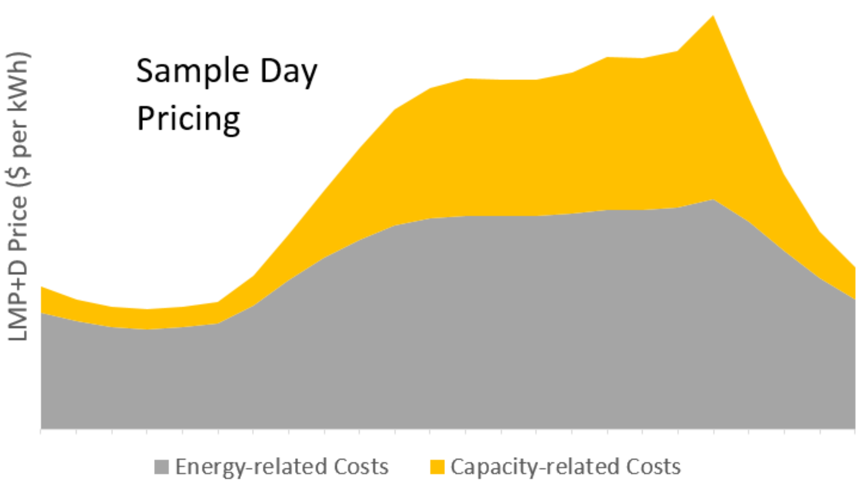
Our interim proposal is that location-specific and time-specific LMP+D retail rates be adopted that, as applicable, would serve as both a means of charging for consumption and for crediting generation. The rates would be dependent upon the installed meter type: our preference is for an interval meter that measures imports and exports on an hourly basis. Although a TOU meter that measures imports and exports over defined TOU periods would also work, we would only support this option if offered in parallel to the hourly option. Rates would be developed for both meter types and assigned to customers for the interim period based on the installed meter type and the applicability criteria defined above. As LMP+D begins to be used, retail-rate NEM would continue to apply until caps are met and would still be applicable where interval or TOU metering was not available. Bill crediting would be the mechanism for applying compensation, and because the value of the credit is based on hourly prices, the credit would be monetary, not volumetric.

We recognize and support the need to increase the granularity with which electricity is priced (and valued), in order to more fully realize the benefits of REV. Yet this must be balanced with the added complexity that this entails. Our proposal is guided by our belief that a majority of the benefits can be achieved without the need to get 100% of the way to completely accurate time and location differentiated pricing. Rather, by moving in that direction over time, the interim methodology can begin to realize benefits in the near term, while maintaining a manageable level of complexity and still making DER opportunities available to customers. For this reason, whether for energy, capacity or other value components (e.g., externalities) our LMP+D rate would be expressed in \$/kWh.

Consistent with this simplified approach, our proposal assigns the same value to generation that is produced and consumed behind the meter and to generation that is produced behind the meter and exported. While a more granular analysis may show that these have different value (e.g., due to different costs to the DSP to integrate the DER), at least for the interim methodology, this simplifying approach will be sufficient and is justified by the need to establish a workable interim methodology in the near term. In any event, it is our belief that the Commission intends for the utility, acting as the DSP provider, to make investments in the grid that will facilitate greater export of power and two-way energy flows. As such, at least some of the investments needed to achieve this can be broadly viewed as falling within the basic service responsibilities of the utility/DSP, and would therefore not be applied to any one particular project, but rather made part of base rates

Hourly variable rates for a given day are illustrated conceptually in Figure 1. While the LMP+D rates would be made up of all components detailed in the BCA Framework Order,[22] only two generic component types are included in the figure for purposes of illustration. These are an energy-related component and a capacity-related component.[23]

Figure 1. Hourly LMP+D rates with two component types (illustrative).



The illustration suggests that the energy- and capacity-related costs may correlate, and that the combination of pricing may be pronounced during the peak hours. It also reinforces the possibility that even relatively small amounts of generation or load reduction during the highest pricing peak hours could result in significant benefit, and that for similar reasons hourly pricing would be expected to vary more than pricing that is averaged over longer TOU periods.

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[22] In fact, as stated by Staff in the Notice (at page 3), "the BCA Framework in and of itself, may be insufficient to represent the full value of DER in certain applications." The advanced energy community strongly supports full valuation of DER benefits even if some values are not included in the BCA Framework Order.

[23] Participants would also incur charges to cover costs not related to energy or capacity, as is currently done in New York, but this is not shown in the figure. This is described further in the subsection "Costs Incurred by Utility: Avoidable and Non-Avoidable Costs."

Computing Hourly Prices Under LMP+D

Hourly prices are calculated at bill settlement once relevant data is available, such as settled LBMP prices for a given node (day ahead and real time), and hourly loads for NYISO and the distribution planning areas. The methods for calculating all component prices are given in the Appendix. The total hourly price is the sum of all component prices for the hour, including avoided generation capacity, avoided energy, avoided transmission capacity, environmental benefits and other quantified benefits from the BCA Framework Order.

Hourly prices may be directly used in bill settlements for LMP+D consumers and producers with interval meters. This would be the case for both the interim and full methodology phases. If the Commission decided, after weighing the factors described in the introductory section, to also calculate LMP+D rates based on TOU meters, then rates could be calculated from the hourly LMP+D prices through load-weighted price averaging within each defined TOU period. TOU periods would also have to be evaluated prior to implementation and fixed for the duration of the interim period. Of course, existing TOU period definitions could be used, provided that they corresponded to both system and local load profiles.

Bill Calculations

Bill calculations would be similar for all customers on the LMP+D rate. A consumption-only customer without generation (e.g., with DR) receiving service under the LMP+D rate would receive a bill calculated as follows: multiply usage by variable price (shown in the figure) for each time-interval over the billing month, sum these, and add the customer charge. A DG owner (generation-only, without load, such as a CDG project) on the LMP+D rate would be compensated as follows: calculate total credits by multiplying generation by variable price (shown in the figure) for each time interval over the billing month, and sum these. Payment to the DG provider would be made in the amount of total credits minus the customer charge.

A customer with BTM generation may be either credited or charged in a given hour, depending upon generation and usage. The variable credit would be calculated by multiplying hourly export energy by the variable price, and summing over the month. The variable charge would be calculated by multiplying hourly consumption by the variable price, and summing over the month. The bill amount would be calculated by taking the variable charge, subtracting the variable credit, and adding the customer charge. This may result in an overall monthly charge or credit, as the case may be, and overall credits would be carried over for use in future billing months.

Monthly Bills under LMP+D

Customers are charged and credited based on consumption and production. Under the LMP+D rate, there are no minimum bills, and excess credits may be carried over to future months (and ultimately cashed out at year end, if the customer elects this option).

As illustrated in Table 2, customer charges accrue to all participants. As described above, these charges expected to be the same or similar for LMP+D customers and for customers on traditional retail rates, and are used to recover utility costs that are not avoidable or deferrable with DER, such as customer service and metering/billing. Production is credited based on the hourly price at the time of production, and these are summed over the billing month. Similarly, consumption is charged at the hourly prices at the time of consumption, and these are summed over the billing month. The final bill results in a total charge or credit.

Credits for remote net metering and subscriber share of community resources would be applied as production credits.

Table 2. Example Monthly Bills Under LMP+D for different types of customers

	Consumption Only	Consumption with BTM Production	Production Only
Customer Charge	$10	$10	$10
Production Credits		($20)	($1000)
Consumption Charges	$20	$5	
Total Charges (Credits)	**$30**	**($5)**	**($990)**

Costs Incurred by Utility: Avoidable and Non-Avoidable Costs

The methods for calculating hourly prices are detailed in the Appendix. These calculations all correspond to the categories in the BCA Framework Order that are recognized by the Commission as potentially avoidable by DER. Some utility costs are not avoidable by DER, however, and these must be paid by all customers, whether taking service under the LMP+D rates or other approved rates.

The potentially avoidable costs are "variable costs" insofar as they depend upon the amount of DER energy. The hourly prices used to compensate DER for its benefit of avoiding variable costs are likewise variable: the price in each hour is energy denominated and expressed as $ per kWh.

The non-avoidable costs, on the other hand, are not variable because changes in production and consumption due to DER behavior do not reduce the costs to the utility. The costs to install a pole or trim a tree, for example, are not variable because they are not dependent upon the amount of DER energy in a given hour.

Furthermore, the non-avoidable costs benefit all users of the DSP, including both non-participating customers and LMP+D customers, and they are allocated by customer class (residential, commercial, etc.). They are not allocated to LMP+D customers as a separate class; LMP+D customers pay the same costs as other customers who receive service under other rate schedules.

The LMP+D rate is designed to apply equally to both production and consumption, and the recovery of non-avoidable costs is handled through a separate transaction. One method for this may be through a monthly customer charge, say, related to the size of the service (e.g., Amps or kVA), but this is a design issue left to the Commission. Regardless of the method for recovering this cost, it is essential to note that LMP+D customers are able to receive production credits at levels that may offset that charge. This is illustrated in the above table in which the BTM production results in a total bill that is negative. Under the LMP+D rate there are no fixed minimum bill charges that require a positive bill payment.

Direct Participation in Wholesale Markets

We expect that over time, individual customers, or aggregated sets of customers (via a third party or possibly the DSP), will be able to participate directly in NYISO wholesale markets. For these customers who elect to do so, we propose that, for the wholesale product markets in which they are participating, the credits for these products be netted out of the LMP+D rate to avoid double counting.

Hourly Price Forecast Signals

Note that it is not possible to know with complete certainty what the prices will be in developing daily planned dispatch of DER.[24] Public or private forecasts of LMP+D rates may be developed for this purpose. For example, web-based price forecast services could be used by smart thermostats, fuel cells, micro-CHP, storage devices, and other DERs to plan optimal dispatch.

Whether the price signal is provided by the DSP or by a private subscription service, the DSP provider would have to publish key input cost and other data that drive the price calculations, such as the current distribution costs and the projected capacity upgrades. These are inputs to the price that only the provider knows, so they would have to be published. Similarly, the expected and measured hourly loads

[24] NYISO day-ahead energy prices are known and they can be used for this purpose. However, these are adjusted through the real-time market, and other price components, such as avoided line losses, are load-dependent and so are not known with certainty.

by distribution area should be published as they are available, such as through a web server designed for software service providers.

These hourly price signals could be used to govern the dispatch of DER and so therefore should represent the full variable forecast price. Day-ahead price forecasts should be sufficient, although these could be updated, say, on a 36-hour moving window basis. The NYISO day-ahead market prices could be used, along with DSP data and load forecasts, to calculate estimates of full LMP+D prices in the next 36 hours. The price signal could then be used to optimize the best times for charging and discharging energy storage, scheduling DR, dispatching fuel cells and other controllable DG, precooling buildings, and so on.

Multiple price forecasts could be developed by competing vendors and compared for price accuracy. Similarly, solar forecasts could be used as well. A customer with solar + storage could use the solar forecast to determine whether it is more advantageous to discharge its stored energy midday, or retain it for later use, given the forecast of solar availability in the afternoon.

Ensuring Financing for DER under LMP+D

Our proposal will likely result in greater price variability, and therefore greater uncertainty, in compensation rates as compared to traditional retail rate NEM. There is also the potential for the "value of D" to vary over time. And yet, the ability to drive down both the LMP and the "value of D" (at least on average) over time will be a key measure of success with REV, as it will indicate that DER deployment is having the intended effect. Thus, in order to encourage DER providers and consumers to pursue projects under the LMP+D rate, it will be necessary to provide a degree of predictability for expected revenues. This does not mean that revenues need to be known with 100% certainty over long periods of time, but suggests that the "value of D" should have a measure of predictability. We detail below, in our response to Question 10, a number of options the Commission should consider in order to ensure that capital can continue to be raised under reasonable terms, that DER products and services can be designed that will appeal to customers, and that DER providers and customers will be interested in developing a range of projects under the LMP+D rate.

Q2. Input Assumptions and Analysis

For each mechanism proposed, or for any mechanism ultimately adopted, identify the input assumptions and the types of benefits and costs relevant to the mechanism, including analysis of their relative significance in magnitude.

Input assumptions and types of benefits and costs are described for each component separately, and these are covered in the Appendix.

Q3. Existing Projects

How can the contractual and financial expectations of existing projects be respected?

As described above, preserving compensation mechanisms that apply to existing contractual arrangements is critical to maintaining confidence in the market, especially during times of change. As such, our proposal includes grandfathering of current rate structures and DER compensation mechanisms for existing projects, as well as those at advanced stages of development where contracts have already been executed but where projects may not yet be operational. Specifically, this would include projects that are interconnected, are under an interconnection contract, or have paid for their CESIR, within six months after the Commission issues its final order establishing the valuation of the LMP+D rate. Moreover, assuming retail rate NEM would continue to be available in parallel to LMP+D (e.g., if NEM caps have not yet been reached), projects that become operation under NEM would continue to be eligible for NEM even after caps have been reached. Under our proposal, all such systems would continue to qualify for full retail rate NEM for the life of the project up to 25 years from the date that the LMP+D compensation mechanism is put into place. As discussed earlier, this is consistent with how the Commission is treating certain RNM projects. The specifics of our proposal are covered in the section "Applicability of DER Compensation Options" and in **Table 1** under "Existing NEM Systems."

Q4. Bill Impacts

Bill impacts are a critical metric for assessing any proposal. How should bill impacts be identified and analyzed? What criteria should be employed to assess the bill impacts of a given proposal?

DER on the supply side, including both separately metered DG and exports, displaces energy and capacity procurements that the utility has to make in order to meet its total load obligations. DER supply is therefore complementary to conventional sources of supply. The total cost incurred in meeting supply requirements is the sum of the costs from both conventional sources (such as NYISO wholesale products) and from DER sources. Under this proposal, all ratepayers pay for the total costs of supply, whether from conventional sources or from supply-side DER.

Demand-side DER, on the other hand, is not directly metered for billing purposes (e.g., efficiency, DR). This form of DER is similar to DG in that it reduces the need for conventional supply, but it is compensated through reduction in usage rather than through payments to suppliers. Therefore, the calculation of total supply cost that must be recovered in rates does not require the quantification of demand-side DER.

Payments to DER suppliers therefore represent costs that would have been paid to conventional suppliers but are instead paid in the form of LMP+D compensation. Non-participating ratepayers are therefore generally not impacted relative to a non-DER "business as usual" scenario. There are two exceptions, however: (1) clean energy is now credited through the social cost of carbon (SCC) mechanism[25] whereas before the social costs were not fully recognized, and (2) avoided distribution capital costs represent avoided future costs, rather than current payments on past utility investments. Both of these will increase rates to the extent that clean DG is implemented. Note that the inclusion of SCC costs will increase rates regardless of compensation mechanism adopted, so the evaluations of alternative proposals may not be significantly differentiated on this account.[26]

With respect to the avoided future distribution costs, this proposal departs slightly from established ratemaking practices. Customers would be asked to "prepay" for future distribution capacity by compensating DER according to its ability to displace the need for future investment. This approach is similar to approving prudent investments based on future anticipated capacity needs, but is different in that the specific plan and costs may not yet be fully known. As our proposal includes the recovery of both historical, sunk costs (currently embedded in rates) as well as future avoided costs (partially embedded in rates), rates for all customers would be expected to increase in the near term. The quantification of increase could be estimated through a comprehensive bill-impact analysis, which should include the effect of DER on reducing LMPs by flattening out system-wide peaks. Importantly, we note that an objective of REV is "enhanced customer knowledge and tools that will support effective management of the total energy bill."[27] As such the bill impact analysis should be less focused on rates and more focused on impacts to total customer bills.

It must also be understood that while this proposal could increase rates in the near term in order to account for the benefits of DER, the total customer billing costs over time may not be significantly

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[25] Or, as described in our alternative proposal, all NY emitters are charged based on carbon emissions, increasing wholesale costs by the SCC. If the Commission adopted this alternative, then rates would also be increased to account for the environmental impact of polluting sources.

[26] However, the selection between crediting clean energy versus charging emitting sources for societal impacts would result in cost differentiation, depending upon the amount of "dirty" versus "clean" energy.

[27] Case 14-M-0101, *Order Adopting Regulatory Policy Framework and Implementation Plan*, February 26, 2015, page 4.

affected and may actually decrease. This is because the proposed calculation method incorporates the discounting effect of the time value of money (which also mitigates the short-term rate increase). A bill impact analysis designed to estimate the long-term (rather than immediate) bill impacts could compare two alternatives:

- The proposed LMP+D rate which includes the discounted value of future avoided distribution costs; and
- A baseline scenario which includes the future distribution costs in future rates, but these are discounted for comparison purposes in the analysis.[28]

Both of these scenarios would be similar when taking into account the long-term bill impacts of the customer. Since the long-term benefits of DER to the system will be experienced by all electric consumers, rather than focus on short-term rate impacts, the Commission should focus on long-term value. It may take time to see widespread reductions in bills resulting from the impacts of DER, but system-wide efficiencies – including reduced transmission and distribution investment and improved capacity utilization throughout the system – will deliver the long-term savings envisioned under REV.

Q5. Benefits and Costs

For each mechanism, describe with as much specificity as possible:

A) The benefits and costs to:

i) participants;

ii) non-participants; and

iii) society

The benefits and costs that would be realized under this proposal relate directly to the BCA Framework Order. This proposal does not re-classify benefits and costs except to acknowledge that costs required to meet the REV policy objectives should be shared equally by participants and non-participants, because benefits will likewise accrue to participants and non-participants. For example, costs incurred by the utility to enable DER through new protection schemes compatible with two-way power flows, voltage

[28] The analysis could be done, for example, by estimating costs to the customer over a long term (e.g., 20 year) period, discounting them and calculating either the NPV or a theoretical, levelized rate.

regulation, and line reconductoring should not be not borne solely by DER generators, but rather by all ratepayers.

In the context of REV, "society" can be thought of as the combination of participants and non-participants, and as such there would not be any costs to society, other than those incurred by utility customers.

B) How the benefits and costs vary when the customer is demand billed versus non-demand billed.

Under this proposal, none of the LMP+D participants will be "demand billed" because traditional demand billing does not capture usage during the coincident peak times. Rather, all LMP+D participants would be interval metered and charged or credited based on hourly metering. Furthermore, demand billing would complicate the price signal – does the customer respond to the demand price or the energy price at any given time? For example, a customer may want to charge energy storage at off peak times. This could increase the demand charge while decreasing the energy charge; i.e., the price signals may conflict.

For CDG and RNM projects, the value of the credit is based on the location of the project, not the location of the account receiving the credits. Also, since the total amount of the credit is based on a time-varying rate, crediting must be done on a monetary basis and not a volumetric basis. This monetary crediting would be identical regardless of the type of account be credited, whether it was a demand billed or non-demand billed account.

C) How the benefits and costs vary when the project is targeted to a system need versus randomly distributed.

Benefit component calculation methods are described in the Appendix. Our proposed approach does not need to explicitly distinguish between targeted versus randomly distributed projects because the computation of the value of LMP+D will be based on actual performance of the DER resource toward meeting locational needs. For example, the energy benefit, derived from settled LBMP costs, would be common to all participants on the distribution grid that share a given locational pricing node. Generation capacity benefits would be common to all participants within a given distribution company service territory. Distribution capacity benefits would differ for each distribution planning area because of different costs per kW and different forecasted timing of future capacity (areas requiring near-term upgrades would result in more benefit than areas with large amounts of excess capacity). In this sense, distribution benefits are "targeted" through differential rates, dependent upon the location of the project. The proposal is simplified with respect to loss calculations, however, such that all customers connecting at a given voltage level (e.g., primary voltage) would be offered pricing regardless of location on the distribution system.[29]

D) How the mechanism applies to energy injections into the grid, versus load reduction.

Participants may be thought of as either LMP+D consumers (e.g., load-reducing DER customers who elect the LMP+D pricing option), LMP+D producers (e.g., community DG providers), and blended LMP+D consumer/producers (e.g., customers with BTM fuel cells) who may either produce, consume or both produce and consume in a given hour.

Nevertheless, it is important to note that the hourly price for LMP+D generation and the hourly price for LMP+D consumption would be very similar. This is because the methods for allocating costs based on hourly loads is identical, and the pricing inputs are similar. For example, ICAP costs are passed on to LMP+D consumers using the same method that is used to set prices for LMP+D producers. On the other hand, hourly pricing for LMP+D distribution capacity may not be identical because the cost recovery for consumption includes a blend of both historical costs and avoided future costs, while compensation for DER generation only recognizes avoided future costs. These would be expected to be similar, however, in locations where near-term capacity is needed.

Similarly, it could be argued that the value of generation exported onto the grid should be less than generation consumed behind the meter because the former may require additional investments in grid infrastructure to accommodate energy exports. However, this may be offset by reductions in the cost of distribution capacity due to generation being consumed behind the meter. Moreover, such investment may not, in fact, be necessary, in which case the value to the system would be the same for both injections and load reduction. Also, it is not possible to know ahead of time for each project (particularly in the case of many small projects) which ones will trigger such infrastructure investments. Moreover, to the extent that the DSP is expected to make such infrastructure investments as part of enhancing its basic service capabilities, consistent with the overall objectives of REV, it would not make sense at this time to assign a different value to energy injections versus load reduction.

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[29] A further refinement could require that utilities perform loss computations at the distribution planning area level, rather than the service territory level. However, this improvement in accuracy may not justify the additional complication.

For these reasons, we propose to treat energy injections and load reductions (whether via BTM consumption of generation or load shifting) the same. Even if there were some differences, we believe the benefits of using the same value for the sake of simplicity and successfully implementing the interim methodology in a timely manner, and also to put all forms of DER, whether DG or load management, on an equal footing with respect to their ability to be paid for performance, outweigh any costs associated with the differences. This will increase the diversity of DER options being considered and deployed, and thus further support REV goals.

At some point in the future, as the level of DER penetration rises, more significant grid investments may be necessary to accommodate further deployment. The decision to make these investments would be subject to the BCA Framework Order and would then affect the locational component of the LMP+D rate or the cost to interconnect to the system.

Q6. Other Implications

Describe how the mechanism would affect and reflect: (A) more accurate and precise value signaling; (B) simplicity in the customer experience and ability to encourage customer adoption; and (C) the Commission's REV policy objectives.

(A) As described above in our response to Question 1, our proposal is designed first and foremost to provide more accurate and precise value signaling based on location and time. The proposal incorporates hourly pricing in energy, generation capacity, transmission capacity, distribution capacity, transmission loss savings, and distribution loss savings. Hourly pricing for energy reflects the true cost of delivery to the applicable pricing node. Hourly pricing for capacity will result in more accurate capacity costs, particularly if the option is selected for pricing proportional to loss-of-load probability. Hourly pricing for losses reflect the true time-varying nature of variable losses.

(B) The pricing mechanism adds complexity to the bill calculations relative to established practices but this process occurs "in the background" and there is no reason why a customer's bill need be any more complex than it is today. From the customer perspective, the concept of hourly pricing may not be difficult to understand, just as customers understand that pricing for many products and services increases with demand and varies with time and location.[30] Despite familiarity with the concept of

[30] Consider, for example, airline tickets, tickets to sporting events, and perhaps the more relevant example of Uber surge pricing, which occurs in real time depending on the relative supply and demand for drivers.

variable pricing, it is important to ensure that customer education and outreach are part of any change in rates. Still, our proposal will result in customer bills that are simpler than if a separate demand charge were imposed. Moreover, with a wide range of "smart" technologies available and emerging, and customers' increasing comfort and familiarity with smartphones and similar devices, it will be feasible for the utility and for third-party DER providers to design programs and products that result in a simple, engaging customer experience.

In terms of customer adoption, a key benefit of the proposed hourly prices is that these more accurate pricing signals would result in significantly greater price differentials between on-peak and off-peak pricing as compared to conventional TOU pricing. This is because the capacity, energy, and loss savings benefits are all load dependent (especially to the extent that the distribution peak coincides with the NYISO system peak). Under TOU pricing, costs are averaged over many hours, diluting the hourly differences in value. Furthermore, the pricing will adjust over time to reflect new hourly pricing patterns as usage shifts from more expensive hours to less expensive hours or as solar penetration shifts net system peaks to non-solar hours.

This increased pricing differential will drive customer adoption more significantly and appropriately (in terms of aligning costs and prices) than conventional TOU pricing. Greater differentials will stimulate demand side management (DSM) implementation, such as building pre-cooling and energy storage adoption. In the case of energy storage, off-peak charging energy will be lower cost and on-peak discharge energy will be higher benefit. Furthermore, the duration of the pricing peak will be narrower, providing a path to energy storage at lower capital cost because these narrow peaks could be met with lower energy storage capability. Demand response, smart building controls, and dispatchable DER will all benefit from more accurate hourly pricing signals and will lead to new innovation in technologies and technology hybridization.

Customer outreach and education are critical and could be accomplished in multiple ways. Utility websites could incorporate a simplified, customer facing description of the new rate and how it is used in calculating DER compensation. The websites could be designed with LMP+D bill calculators, similar to solar bill calculators but expanded to cover a range of technologies. These calculators could be tied to the specific customer usage so that bills could be compared using actual loads but with multiple scenarios, such as the incorporation of a fuel cell operating during peak hours. In addition, advanced energy companies are leaders in developing ways to educate and engage customers, and the implementation of the LMP+D rate presents an important opportunity to continue to refine those techniques. Some companies already work directly with utilities on customer engagement, for example with behavioral energy efficiency programs or in using AMI data to provide high-usage alerts or to communicate demand reduction opportunities as part of peak time rebate or critical peak pricing programs. Others connect with customers on their own behalf to market their products and services. For existing customers, they provide tools and resources for monitoring and managing DER and are increasingly providing opportunities for customers to engage with each other (e.g., via social media and other means) and to engage prospective customers to grow their business. All of this can be brought to bear to encourage both customer adoption and effective utilization of the DER assets.

Despite these opportunities that will emerge with implementation of the LMP+D rate, a shift from retail rate NEM to LMP+D may pose some challenges, particularly in the near term, to customer adoption of DG. Below in our response to Question 10, we provide some specific recommendations on how the Commission can ensure that DER providers will be able to finance DER projects under the LMP+D rate by addressing the issue of price predictability. Customer adoption could also be encouraged with shadow billing to aid in decision-making.

(C) The proposal will meet the Commission's REV policy objectives as follows:

(1) Enhanced customer knowledge and tools that will support effective management of the total energy bill. The transition to hourly pricing will lead to new technologies, smart control strategies, and DER adoption for the reasons described above. The DER industry would benefit from private or public pricing forecasts to drive smart devices (e.g., thermostats that respond to anticipated pricing in coming hours). It would provide customers greater choice and the ability to impact customer bills.

(2) Market animation and leverage of customer contributions. The pricing scheme, with appropriate customer education and outreach, would motivate customers to provide generation or load reduction during peak hours. Customers would respond to these signals in a rational way, and the effects would be compounded. In the case of distribution capacity benefits, DER resources would be directed to locations and times where they are needed most, combining the effects of multiple customers and resulting in the desired technical outcomes such as deferred or eliminated distribution capacity upgrades.

(3) System wide efficiency. Hourly and locational pricing would lead to greater efficiency in the location and dispatch of resources, such as areas with high LBMPs or near-term distribution capacity needs. Time-differentiated prices on an hourly basis would lead to dispatch of resources during the highest peak times, and this would displace costly and inefficient generating resources. It would further alleviate the need to generate significant excess power that is lost in heating in wires and transformers by reducing peak loads. In addition, the pricing signals would work to level the loads and improve overall load factor for greater economic efficiency.

(4) Fuel and resource diversity. Our proposal is designed to encourage multiple forms of DER and will lead to new opportunities for dispatchable DG and DR and also for energy storage which would,

in turn, facilitate solar energy and distributed wind deployment. Solar and wind generation could be installed more economically with storage, so that customers operate their resources and control their loads efficiently. Such a transition would make solar and wind more desirable and avoid some of the technical challenges, such as peak load shifting and ramp rates, which without storage may limit the adoption of solar in particular. This increase in renewable energy deployment will offset other fuels such as coal and natural gas, whereas an increase in other forms of DG, such as fuel cells and micro CHP, will provide additional resource diversity. Furthermore, the adoption of storage would itself be a form of resource diversity, and this could lead to higher volumes and lower capital costs of storage. At the same time, our proposal preserves retail-rate NEM for certain resources to support continued deployment of smaller BTM DG systems, consistent with the intent of the Commission as articulated in the Track 2 White Paper.

(5) System reliability and resiliency. The system will improve in reliability for several reasons. First, the REV objectives include the vision of the DSP operating with a new charter to accept distributed resources. The DSPs would be designed to integrate, and not just interconnect, these generating sources and provide for improved system protection relative to today's environment. Second, the adoption of DER resources, in greater number and with greater technology diversity than today, will add significant redundancy to the power grid. The system will be less reliant upon key transmission and generation resources because the supply will be diversified at the grid edge. As for resiliency, some DERs (and combinations of DERs) could be designed to operate both in parallel with the grid and islanded. This will allow for customers to continue operations during grid interruptions, something not possible, nor encouraged, under current pricing schedules, and will improve the economic feasibility for applications such as storage. Moreover, to the extent our proposal promotes a diversity of DER resource types, we can envision a future where the DSP will be able to draw upon these resources in such a way as to support grid reliability and resiliency even if these resources are owned by multiple entities/customers.

(6) Reduction of carbon emissions. As described above, our pricing proposal will facilitate peak demand reduction, and this in turn will result in the reduced need for power from generating units with the highest heat rates (and therefore the highest carbon emissions rates). Transmission and distribution losses should also be reduced, as these losses tend to be higher during peak times. More broadly, existing generating units will be displaced over time with the improved viability for solar, other renewables and clean DG such as efficient fuel cells and CHP. Increased deployment of energy efficiency as a resource will reduce total demand and so also drive down total system emissions.

Q7. New Technologies

Describe how the mechanism would be consistent with current or foreseeable enabling technology.

Our proposed mechanism is fully compatible with current DER technologies as well as those on the horizon, including DG with smart inverters.[31] As described above, the transition to hourly pricing will provide additional impetus to deploy technologies and control strategies that minimize coincident peak loads. To take one example, the proposed pricing mechanism would provide significantly better economic returns on investment for load shifting strategies. This would include building pre-cooling strategies that take advantage of the thermal mass of buildings. Pre-cooling of the mass would be triggered through smart thermostats that communicate through price-aware servers. By shifting loads to earlier in the day, the cooling effect can be enjoyed during peak hours without operating HVAC equipment. This technology is available today at reasonable cost. Similarly, thermal storage (e.g., ice storage) would be incented under our proposal.

Fuel cells and energy storage have matured to the point where they are technically ready, but current rate structures are not designed to capture their full range of benefits and capabilities. Through the price differentials described above, fuel cells and storage could be employed in New York in great abundance and find application in customer facilities large and small. These technologies could also be built at the community level using LMP+D rates. Potentially, DER providers could offer community hybrid resources also based on LMP+D hourly pricing.

Controls and tools would be developed including price forecasters, remote device controllers, thermostat setpoint servers, and solar forecasting services. These services would all revolve around LMP+D pricing and enable automated control of user loads and DER resources to maximize savings and enhance system efficiency. All of these technologies exist today but customers cannot see their full value due to the limited price signals of existing rate designs.

Providing information to customers on prices and educating them on their significance and the opportunities to reduce costs that would then make sense economically will be key to getting customers to respond to system needs. Advanced energy companies already work closely with utilities as well as on their own behalf on increasingly sophisticated customer engagement strategies. As part of the sign up process for the LMP+D rate, the utility should identify the customer's preferred communication channels,

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[31] Additional benefits of smart inverters may be an additional value component that could be considered by the Commission once approved for installation and voltage control methods become standardized.

such as email, text, phone calls, dedicated mobile apps, and Twitter, and communication thresholds (e.g., NYISO day ahead prices or current per kWh price over 40 cents).

With regards to metering and communications, our interim proposal relies on the use of currently available interval metering technology, and as a second choice, TOU meters. Once AMI is deployed, our interim methodology could easily transition to the final methodology using the greater functionality provided by AMI. As also described above, many DER providers currently include near-real time monitoring and metering of DG over public communications networks, can provide automated demand response, and have developed their own sophisticated control centers and customer-facing applications to support their business models. These private sector investments could be leveraged to support implementation of the interim DER compensation methodology, e.g., to track DG production to support compensation based on the LMP+D rate and for calculated the emissions credits for same.

Q8. Changes to Rate Design

Describe the extent to which the mechanism relies on changes in rate design, including whether rate design changes to implement the mechanism would apply only to participating customers or apply to all customers.

This mechanism relies on changes in rate design for participating customers in order to provide customers with more accurate price signals that are not possible under current rate design. The methods for determining the LMP+D rates are of course new. Also, as DER supply is brought online, other rates would have to be adjusted to account for the reduced share of conventional supply and the increased share of DG supply, although this does not necessitate a change to the structure of the rate itself. Note that while LMP+D rates are location-specific, the allocation of costs in rates applicable to non-participants do not have to be location-specific. They may be shared across the whole service territory.

Q9. Cost Recovery

Describe the implications of the mechanism for fair, efficient, and sustainable recovery of distribution system costs.

These objectives are inherent in the proposed LMP+D rate design. The costs would be fairly borne by all ratepayers because they enable all ratepayers to participate in the new marketplace, should they elect to, either by modifying loads or by installing and operating distributed generation. Benefits are also shared, such as reductions in LBMPs and reduced utility capital investment. The proposed rate provides for recovery of existing distribution system costs while enabling future distribution capacity to be provided by DER at costs defined by the utility cost structure. The allocation of costs is fair based on the principle that all ratepayers share in the cost of all services, whether provided by the NYISO market, by the distribution utility, or by DER.

The allocation is efficient in that it results in pricing that accurately reflects actual costs. It does not rely on long-term forecasts of fuel prices, fuel mixes, or adoption rates. The only long-term forecast is a technical forecast of distribution capacity needs. It enables DER to be installed incrementally as needed, rather than relying only on large "lumpy" investments of over-sized distribution system equipment that may not be needed in the future as DER deployment rises.

It is also sustainable based on the fact that the utility still has responsibility for planning a safe and reliable system. To the extent that DER is able to reduce peak loads, as is expected through pricing strongly tied to hourly loads, it will be possible to eliminate future capital expenditures on electrical plant. Under such a scenario, DER will assume more of the burden for capacity and energy, and the utility will have the measured output of these resources to reconstruct total load for planning purposes. In this case, distribution assets will depreciate and eventually may need to be replaced, and maybe not. Or, the assets could be replaced with equipment at lower rated capability. The total capitalization of the utility may be reduced, but only if DER is able to provide the expected services. Thus the cost to the customers will decline over time with declining need for the delivery of central resources. At the same time, the services for DER could continue, and the DSP provider will be responsible for facilitating the transactions between participating and non-participating customers.

On the other hand, if DER is unable to meet peak loads or distribution system needs in sufficient amounts to ensure reliability, then the utility will have to take action in accordance with their "universal service obligations."[32] Such future investments will be recoverable through the same LMP+D rate mechanism as proposed to recover existing costs today and utilities will be entitled to earn the established rate of return.

The pricing mechanism proposed here, we believe, will most likely lead to a blend of both scenarios, that is, increased reliance upon DER but additional utility infrastructure investments as needed to ensure ongoing reliability. Our proposal does not directly address the issue of the underlying incentive structures for utilities to pursue investment to establish the DSP and to pursue DER-based solutions. This is the subject of Track 2 of REV, but our LMP+D proposal will work with whatever cost-recovery framework is established by the Commission.

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[32] Track 2 White Paper, p. 1.

Q10. Customer Investment

Describe the implications of the mechanism for fair, efficient, and sustainable customer investment.

Under this proposal, the customer would be able to invest in BTM supply-side DER, BTM demand-side DER, shared community resources, or a combination of the three. Hourly prices (representing the full LMP+D value), and forecasted hourly prices, would be a key indicator of project economics. These prices would support efficient investments in that such investments will be most viable in locations were the prices are highest, and that these high prices will result in shorter payback periods and higher rates of return. At the same time, these investments would provide greater value to the electricity system, thus benefiting customers as a whole and furthering key REV objectives.

Prices would not be "locked in," just as they are not currently locked in under existing NEM compensation. NEM compensation rates change as retail rates change, so long-term evaluations of project economics typically include assumptions about rate escalation. Similarly, under this proposal, trends in pricing and hourly load shapes can be used to evaluate investments over the long-term. However, unlike with NEM, there is a lack of long-term historical data on rates with which to develop projections and associated business models and customer value propositions. Moreover, as the LMP+D framework leads to DER deployment that drives down future utility investment, one can expect that certain components of the LMP+D rate (as well as existing rates based largely on flat volumetric pricing) will decrease over time. Thus, the greater uncertainty with this new rate design presents, in our view, a higher investment risk than with retail-rate NEM, and presents a barrier to raising capital for DER deployment. As such, we believe the Commission should include mechanisms to mitigate this added financing risk as part of the interim methodology. We present several options below.

Published LMP+D Prices

Utilities should be required to publish retroactively-computed LMP+D prices by location based on historical information. This would help guide DER implementation by enabling sample economic evaluations. These published prices could be used to evaluate technology alternatives, develop estimates of customer financials, and improve price-forecasting models. Published pricing prior to implementation of LMP+D would help the industry plan for the new compensation mechanism.

Published prices could include back-calculated pricing for a three year period in advance of the roll-out in order to inform the marketplace what the prices would have been if LMP+D were available over that time. These time series of pricing data could be used to determine optimum DER locational placement, dispatch algorithms, and expected return on investment. They would provide market understanding and insights to both suppliers and consumers of DER.

LMP+D Calculator

Similarly, the Commission could also develop a public LMP+D calculator tool, such as a spreadsheet model, that employs the final price calculation methodology. This would assist with public understanding of inputs (e.g., costs and hourly loads) and outputs (hourly prices) and the sensitivities of the input values.

Price Stability

For this proposed compensation mechanism to be successful, investments must be made in new DER resources, and this will only happen if systems and projects are financeable. A reasonable risk-reward balance is sought, and the following discussion is meant to illustrate risk-reducing elements that could be incorporated into the LMP+D rate design.

It is not our purpose here to fix hourly prices in advance (e.g., by pre-calculating and publishing prices for each hour over the next five years) for this would run counter to the basic philosophy of developing a relationship between price and load. If hourly prices were set before hourly loads were known, then such a relationship would be broken and the benefit of time-varying pricing would be lost.

However, hourly prices follow from a series of prescribed calculations: inputs include various costs and hourly loads, and outputs are the hourly prices. What could be accomplished to reduce investment risk, then, is to add certainty to the calculation inputs. If the inputs were known with some degree of certainty, then the relationship between load and price would likewise be known with a similar degree of certainty. While the prices would not be known, per se, the expectation of price levels from year to year would be known to the extent that the inputs were established in advance.

If such an approach were adopted, the benefit of price stability would come at the expense of some price accuracy. Consider the following example of DER investment risk without price stabilization: a utility may forecast that new distribution capacity would be required in year five, and hourly prices would follow accordingly. DER could then be installed at this location, justified on the basis that the system would command high prices that result from this near-term capacity need. Based on a five year build scenario, prices would continue to rise for the first five years, after which prices would drop for the distribution capacity component in year six.

However, suppose that peak loads grew faster than anticipated, and the distribution capacity was installed in year three instead of year five. In this case, due to the dynamic nature of pricing, the DER investor would have lost the expected benefit of two years of higher prices.

This example illustrates one type of risk: the risk of unknown scheduling of new distribution capacity requirements. To eliminate this risk, an alternative approach could be to provide the investor with scheduling certainty. The five-year capacity increase could be fixed in the rate calculation, despite the fact that the actual capacity increase may take place sooner or later than the schedule. If this were the case, then the resulting prices would be stabilized and the DER investor would eliminate the uncertainty in economic return that follows from this input parameter in the calculation.

While this approach would remove some amount of uncertainty in the DER investment, it would also cause a deviation of pricing that may lead to less efficiency. If the five-year schedule were fixed, and if the capacity increase was made in year three, then high prices would still be available in years four and five. This may in turn lead to additional DER investment at that location in years four and five, yet this new DER capacity would not be needed. The price signal would not provide the same accuracy as a dynamic signal that varies with actual costs. The benefit of price stability in the above scheme would have to be evaluated against the reduction in accuracy of the price signal.

The distribution capacity example above is only one such parameter that could be fixed in order to provide price stability. Any of the other calculation input parameters and any of the intermediate calculation results could be fixed over a desired period of time,[33] such as:

- ICAP prices ($ per kW)
- Distribution capacity prices ($ per kW)
- The market price reduction benefit ($ per kWh)
- The SCC benefit ($ per kWh)

In addition, the duration of parameter fixing could be considered as well. Instead of fixing a parameter for five years, it could be fixed for three years or seven years. These variants could all be considered in order to achieve the best tradeoff between risk mitigation needed to support DER investment and pricing accuracy.

[33] Note that the prices would not have to be constant for the full period, but rather known and certain. The ICAP price could be set for each of the next five years, but each year would have a different price.

In another approach, the above parameters could be fixed for new participants entering the LMP+D rate in a specific year. For example, participants entering in the first year would have selected parameters fixed for years one to five. Participants entering in the second year would have parameters fixed for years two to six, and so on. This approach would also provide price stability, but it would lead to some additional complexity (prices would vary by location, hour, and year of entry). Following each project's five-year window, LMP+D prices could be adjusted more frequently. Alternatively, customers could have their parameters fixed for longer periods than five years, if that were deemed necessary. The Commission could also choose to adopt an approach similar to grandfathering of NEM projects – projects deployed early under LMP+D would receive price certainty for long periods of time, say 10-20 years, and once the overall approach was proven to be viable, the Commission could revisit this aspect of the rate, but not make changes retroactively for projects already in operation.

The Commission could also consider a variation on this proposal in which the LMP+D prices are published and known ahead of time with a time horizon corresponding to the forecast price signal, such as 36 hours. In this approach, the price signal is not just a forecast, but rather a pre-calculation of what the actual hourly prices would be, and these would then be used for settlement purposes. Knowing the prices in advance would provide the DER operators with perfect price certainty, at least for the 36-hour time horizon, and would enable perfect dispatch. It would not provide week-to-week certainty, year-to-year certainty, etc., which would need to be addressed separately, as described above. The energy component could simply be the day-ahead energy market price and the other components of LMP+D could be based on system and distribution area load forecasts using the same calculation methodology proposed here. This approach would trade off day-ahead price certainty with accuracy; it would not be modifiable with each passing hour, so that inaccuracies would be introduced to the extent that loads deviated from the assumed profiles.

As actual data on costs begins to be made available, analysis of different options will need to be performed, with involvement from the DER community and the finance community, to understand the viability of different options vis-à-vis investment requirements as well as achieving desired outcomes in terms of utility cost avoidance and other REV objectives.

The Commission could also consider front-loading payments in a manner similar to what ConEdison does with its DR programs, although this would require some sort of verification of performance.

Finally, if the market is failing to materialize, the Commission could consider authorizing some form of incentive payments over and above the hourly LMP+D rate to incent participation.

Q11. Avoided Distribution Costs

Describe the extent to which the cost of providing distribution service to individual customers utilizing DER is or could be avoided by the DER.

This is addressed more fully in the Appendix, but the following points should be noted:

- The cost of providing distribution service includes both historical (sunk) costs, not avoidable by DER, and future costs, potentially avoidable by DER. Our LMP+D methodology includes the calculation of estimated future costs and their allocation by hour.
- Some distribution capacity-related costs are avoidable. Some costs, such as some reliability investments and capital costs in the vicinity of the DER would not be avoidable.
- The fair price for avoidable distribution capacity would be paid to DER customers, taking into account the timing of future investments (with near-term needs valued higher than long-term needs).
- DERs will be able to defer or eliminate future infrastructure investments, depending on adoption rates, installed capacity, locations, etc. Under REV, provided that DER does not offer a suitable solution to meeting system needs, to the extent that utilities need to invest in additional infrastructure, they would earn their fair rate of return for prudent investments.

Q12. Application of Mechanism to Different Customer Types

Describe how a mechanism would focus on, or apply to: (A) Residential or small commercial (i.e., non-demand-billed) onsite projects; (B) Demand-billed projects whose output is not substantially greater than the load at the meter; and (C) Large projects whose output is substantially greater than the load at the meter (e.g., Remote Net Metering, Community DG).

The LMP+D mechanism applies to all of these scenarios, except that they would all require conversion to interval metering (or AMI metering) in order to capture the hourly loads. In the case of residential and small commercial (onsite) projects, the LMP+D rate would apply to load reduction strategies, onsite generation behind the meter, or both. For larger customers in which generation output is not substantially greater than the load at the meter, the LMP+D rate would also govern these projects. In the case of large projects such as remote net metering or community DG, the LMP+D rate would similarly apply. In all of the above cases, exported energy (injection into the grid) is compensated at the LMP+D hourly rate for generation and all import energy for participants is billed at the LMP+D rate. Section 4, "Applicability of DER Compensation Options Under the Proposed Methodology," provides a more details of how the mechanism would apply to different customer and DER types.

Q13. How Mechanism is Applied

Provide illustrations of how the proposed compensation mechanism would be applied. Issues for attention should include (but do not need to be limited to): (A) Is accounting accomplished via bill credits or via some other mechanism? (B) Is generation netted against consumption or are energy flows accounted for separately? (C) Is measurement and/or accounting of generation conducted on a volumetric or a monetary basis?

Accounting would be accomplished via bill crediting. Our proposal does not require that generation and consumption be accounted for separately. Generation would be netted against consumption in the sense that the hourly load subject to the LMP+D rate is the net load at the meter in that hour. If there was net export in a given hour, that net amount would generate a credit at the applicable hourly rate. Because our proposed LMP+D rate uses time- and location-specific values, accounting for any credits applied from one bill to the next or between accounts would need to be done on a monetary basis. Additional detailed answers to these questions are described in the section "Q1, Interim Proposal."

Q14. Low-Income Customers

Describe anticipated impacts on participating and non-participating low income customers.

This initial proposal offers no specific adjustments for low-income customers, other than proposing that CDG projects targeted at this customer segment continue to receive full retail-rate NEM crediting. However, adjustments to the basic LMP+D methodology are possible, such as by reducing the cost allocation to participating low-income customers and calculating a corresponding lower LMP+D rate for consumption, or simply offering a discount to low-income customers. Similarly, participating low-income customers with generation could receive higher credits. Hourly generation pricing would probably be the same whether low income or not, but could then be used to offset more energy charges on the lower LMP+D rates for consumption. Non-participating low-income customers could continue to receive discounts, to the extent this is the case today.

Our proposal does open up the possibility for increased participation by low-income customers in areas with high locational value. If the utility and/or third parties are able to identify these areas, there would be an incentive for DER providers to seek out these customers and make DER options available to them. We propose that this be an area of further discussion among the parties within this proceeding.

Q15. Application of Different Technologies

Describe how the mechanism would distinguish, if at all, between solar PV and other technologies currently eligible for NEM.

LMP+D hourly prices are technology-neutral. If a non-solar, clean generation resource produced the same hourly output in the same location as a solar resource, it would receive the same credit amount, assuming they were on the same LMP+D rate and on the same pricing node.

Q16. Accounting for Emissions Reduction

Describe how the mechanism would, if at all, account for the value of emissions reductions.

The mechanism used to calculate pricing for clean energy generation is described in the Appendix (the SCC cost component). However, once the energy-denominated value is calculated, two issues arise in the emissions accounting.

First, some DER generators do emit carbon and should therefore only receive a credit to the extent that their emissions lower the total emissions in the NYISO control area. There are also DER technologies, such as biogas-to-power, that can result in carbon offsets by reducing emissions of other greenhouse gases like methane. A table could be developed to indicate load-weighted averages of emissions by technology, or possibly customized project-specific emissions rates could be used. Pricing would then be adjusted based on these results.

Once the project or technology emissions per kWh was obtained, the total kWh over the billing month for each DG resource would have to be measured, at least for emitting technologies. Non-emitting technologies, such as solar, may not have to be separately metered in some cases. For example, a BTM solar installation may only require metering of net import and export for billing purposes because no emissions would be generated. However, a solar/storage hybrid system behind the meter might require separate metering for the storage component.

In some cases, therefore, additional metering may be needed only for the purpose of evaluating emissions benefits. As these are project/technology specific, this requirement complicates the implementation of LMP+D, although as noted above, these DER installations typically come with their own metering and communications capabilities, which could be used for this purpose.

Similarly, the mechanism as proposed is not able to credit efficiency on the same basis as clean generation because efficiency cannot be metered as DG production can. On the one hand, a clean kWh of generation (e.g., from a solar resource) would be credited based on the SCC value calculation. All ratepayers would pay for this credit. On the other hand, the LMP+D customer who reduces consumption by one kWh would only receive the benefit of not having to pay its allocated cost for clean energy. This may result in a lower benefit than DG if clean DG is small compared to the total system generation.

An alternative is available that would solve the problem and credit efficiency and clean DG at the same rate. This would be to charge all producers in the NYISO control area the SCC based on their individual carbon emissions in the NYISO control area. The cost of energy for all ratepayers would increase, but this would fully recognize the societal impact as quantified by the SCC. If such a mechanism were adopted, it would no longer be necessary to credit DG for the SCC since this benefit would already be fully embedded in the LBMPs. At the same time, efficiency would get the same price-per-kWh benefit as DG because the avoided kWh would result in a savings of the full SCC benefit.

Such a "carbon fee," while only offered here for consideration as an alternative, would therefore serve to equitably credit both supply and demand-based DERs. It may also encourage cleaner generation in the NYISO markets because cleaner sources (e.g., those with lower heat rates) would be more competitive in the marketplace than they would otherwise be without taking emissions into account. The collection of the carbon fee would result in a fund that could be used for several purposes in support of the REV objectives, such as by paying for clean DER, for strengthening grid infrastructure for bi-directional power flows, and funding one-time implementation costs.

6. Developing a Full Valuation Methodology

Q17. Description of Full Methodology

Describe how a full valuation mechanism should account for the following:

A) Variations in benefits and costs between generation that is dispatchable and generation that is variable or intermittent.

B) Which types of benefits and costs should be valued on a fixed basis or on a dynamic basis?

C) For those components where a fixed value is proposed, how often would the value be updated, and by what process?

D) For those components where a dynamic value is proposed, identify the dimension(s) which should be variable (e.g., temporal, locational, service class, gross usage, and the like).

The full valuation methodology is identical to the interim methodology, but simply requires that all time dependency be hourly (or potentially sub-hourly) and does not provide the option for a TOU approximation. It is anticipated that the transition from the interim to full methodology would correspond to the rollout of AMI which would enable hourly (or potentially sub-hourly) metering everywhere. In this case, TOU meters would not be used.

Our interim methodology does not require differentiation between generation that is dispatchable and generation that is variable or intermittent. This would not change with the full valuation methodology. Similarly, there is no change in the differentiation between fixed and dynamic benefits and costs.

There may be some aspects of our proposal that could be shifted between the interim methodology and the full methodology, depending upon the trade-off between desired accuracy and the time it takes to implement. For example:

- Emissions could be calculated using CARIS for the interim but based on actual hourly emissions in the full methodology.
- Common loss factors could be calculated for the service territory in the interim methodology but be done by distribution planning area in the full methodology.
- Distribution costs could be calculated for the service territory in the interim methodology but by distribution planning area in the full methodology.
- A single LMP+D rate could be calculated in the interim methodology but separate rates could be developed by customer class or interconnection voltage in the full methodology.

As the basic principles and methods are the same for both phases, there is flexibility in these types of details, or even decisions about whether the most accurate data is needed at all in the full methodology. For example, the Commission could decide that the loss factors should be the same for all distribution planning areas even in the full methodology in order to simplify the process.

Q18. Time-varying Rates

Describe whether a valuation mechanism should be adjusted for time-varying rates.

The interim proposal is built around time-varying rates, and this is not modified in the full methodology except to eliminate the use of TOU intervals due to their poor precision and their inability to adjust to changing load patterns. If the final methodology were to include sub-hourly time intervals, this would make it more complicated overall, and the benefit of doing so would need to be weighed against implementation costs.

Q19. Price Stability

Describe how the mechanism would balance price stability and risk mitigation (to facilitate market development) against the objective of accurate and dynamic price signals.

In our response to Question 10, we proposed several options for providing additional certainty and price stability with respect to expect LMP+D rates, in order to promote early adoption and reduce risks to DER providers and customers during the transition. As the full methodology is implemented, the Commission could decide to what extent these stabilizing mechanisms would be kept in place versus moving to a more fully dynamic hourly rate.

Q20. Networked DER

Describe the extent to which the system value of a single DER project may be a function of the degree of networked DER penetration (e.g., the total amount of DER on a particular circuit serving a similar set of system values).

Under this proposal, prices are fundamentally set by the relative supply and demand of resources. Large amounts of similar DERs in the same locality will drive prices down to the extent the existing distribution system can integrate them or they help to avoid new distribution investment. For example, consider the case of having significant amount of solar capacity in the same distribution planning area and energy pricing node.

In this case, as the solar capacity increases, the net load as measured at the substations will reduce during the solar hours. This will lead to an oversupply on the wholesale level during those hours, at least within the pricing node, and lower cost resources will be able to serve that load. In addition, transmission will be less constrained, allowing energy to reach the area at lower prices. These effects mean that the supply of solar would reduce the energy price during solar hours.

It would also reduce the price of other components. The ICAP benefit calculation is driven by load, so the lower loads in solar hours would be reduced, as would the distribution benefit in those hours. The benefits of loss savings would similarly be reduced because they are also load dependent.

Flexible loads and dispatchable generation (e.g., fuel cells), on the other hand, would be able to adapt. In the case of these resources serving loads during a high priced hour, the price for that hour would drop. As the peak shifts to other hours and even other seasons, the flexible DER resources would be able to adapt and serve load at the new peak times. Unlike TOU periods, which are fixed in the tariffs (and typically set in the meter itself), the hourly LMP+D pricing scheme would adapt over time to changing load patterns brought about by DER and would ensure that the resources are brought to bear in the most efficient manner possible.

7. Conclusions

The advanced energy community strongly supports the efforts of the Commission in this proceeding, and is committed to playing its part to create a high-performing electricity system in New York State. Our proposal, offered in response to the Commission's Notice, is fully in line with the technical requirements and broad intent of the Notice and the BCA Framework Order. It provides New York with a long-term path to implementing DER in a manner that is fair to both the advanced energy community and to the regulated utilities. It provides a mechanism to meet the REV objectives in a technically achievable, responsible manner.

We believe that the Commission has set forth an ambitious task, one that presents a host of challenges in the coming years, but one that is worthy of our best efforts in achieving it.

Appendix – Component Methods

This Appendix outlines the means to translate the BCA Framework into hourly rates, resolved monthly by using data (such as LBMPs) relevant to the billing month in final bill settlement. Thus, the methods described here are extensions of the methods defined in the BCA Framework, and are arranged using the same headings found in the BCA Framework "Appendix C." This Appendix should not be viewed as a full proposal for valuing DER but as a starting point for further discussions among parties. Importantly, as stated by Staff in the Notice (at page 3), "the BCA Framework in and of itself, may be insufficient to represent the full value of DER in certain applications." The advanced energy community strongly supports full valuation of DER benefits even if some values are not included in the BCA Framework Order, and even if approximations must be made in lieu of detailed calculations.

Also, foundational investment costs that are incurred in order to enhance the grid for the new responsibilities of the DSP are not included. For example, costs to design protection for bidirectional power flow may be selectively required in order to accept DER generation and deliver it to consumers.

Benefits

Avoided Generation Capacity (ICAP), including Reserve Margin

DERs may be able to participate directly in NYISO generation capacity markets. Systems that do would not be compensated under the method proposed here (to avoid double counting). However, DERs that do not participate in these markets may still receive compensation based on hourly pricing.

According to the BCA Framework, the ICAP benefit "applies to the extent to which the resources under consideration reduce coincident peak demand."[34] The hourly LMP+D price component that reflects the ICAP benefit should therefore be calculated as a function of NYISO load so that higher prices apply during periods of high system load and lower prices apply during hours of low system load.

It will be essential to determine a suitable relationship, then, between price and load. Two approaches are offered here, although we have a preference the second approach. In the first approach, price is proportional to hourly load. In the second approach, price is proportional to time interval loss of load probability (LOLP).

[34] BCA Framework, Appendix C, p. 3.

In the first approach, the total cost of capacity, *ICAP* (expressed in \$ per kW per year) is calculated using the procedure described in the BCA Framework. The next step is to weight the relative value by load. So, in hour *t*,

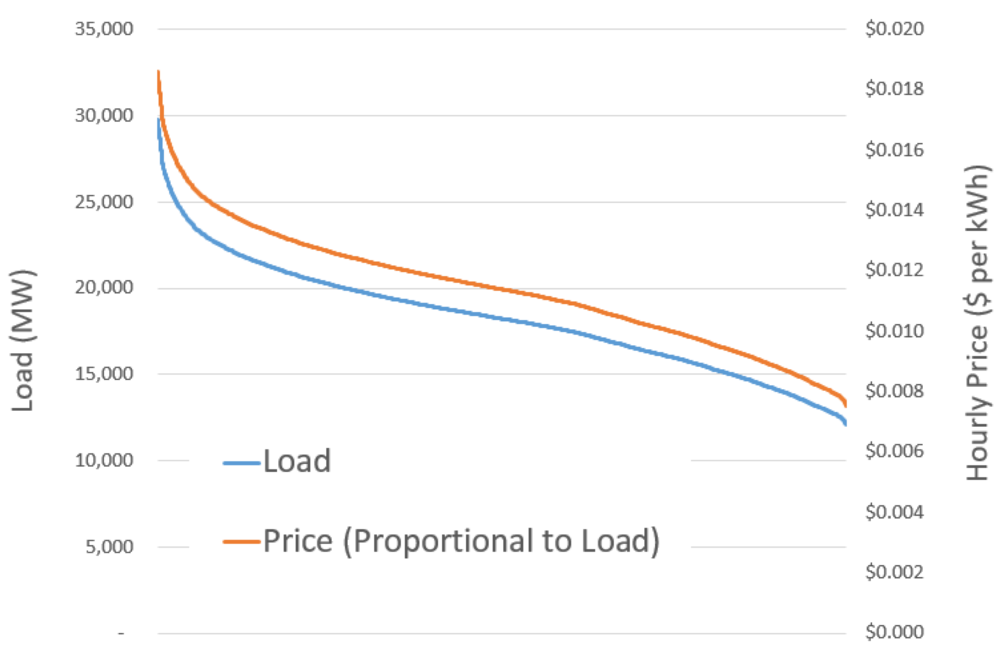
$$Price_t(\frac{\$}{kWh}) = ICAP\left(\frac{\$}{kW}\right) * \frac{SystemLoad_t}{\sum_{t=1}^{8760} SystemLoad_t}$$

Or, more simply,

$$Price_t(\frac{\$}{kWh}) = ICAP\left(\frac{\$}{kW}\right) * \frac{SystemLoad_t(MW)}{AnnualSystemLoad(MWh)}$$

An example is shown in Figure 2, which shows hourly NYISO loads for 2014, sorted by load. The maximum load for the year was 29,872 MW, and the minimum load for the year was 12,057 MW. The total ICAP value was assumed in this example to be \$100 per kW-year, and this total value is distributed across all hours by the above equations. We see that the resulting ICAP hourly price ranges from about \$0.008 per kWh to about \$0.019 per kWh.

Figure 2. 2014 NYSIO Load and Hourly ICAP Price (Illustrative).



The sum of all weighting factors equals 1. This ensures that the total potential value of a "perfect" DER (a baseload DER) results in the full valuation. If a baseload DER produced 1 kW every hour of the year, then the above example would result in a total annual valuation of $100.

The method described above provides for a retroactive calculation of prices for a year. To do this, hourly system loads must be known for the year. However, bill calculations take place each month before the full calendar year is complete, so the full set of input data is unavailable. There are at least two options to addressing this lack of data. Either (1) the billing month is always taken as the end of the calculation year, so that *AnnualSystemLoad* is recalculated each month for a moving window of known, historical loads; or (2) a forecasted annual load, say, for each calendar year, and utility revenues are trued up at the end of each year through a balancing account.

As an alternative to weighting prices proportionately with load, a second method is to weight hourly prices by loss of load probability. Studies of effective capacity for variable resources frequently estimate the "effective load carrying capability," or ELCC. The ELCC of a resource is sometimes defined as the capacity of a firm resource that results in the same loss of load expectation. In other words, the ELCC of a variable resource is a measure of capacity based on its effectiveness in providing reliability. Extending the ELCC concept to the task at hand, the value of DER provided in any given hour is weighted by the ability of the DER to provide reliability to the system and reduce the likelihood that load will exceed available generating resources during that hour.

According to one approximation method,[35] the loss of load expectation (LOLE) for a year is given by:

$$LOLE = \sum_{t=1}^{N} \exp\left(\frac{-(\mathrm{P} - L_t)}{m}\right)$$

In this equation, P is the peak annual load, L_t is the load in hour t, m is a characteristic of the system, and the summation is over every hour of the year (the term being summed is the hourly LOLP). Pricing may therefore be calculated as follows:

$$Price_t\left(\frac{\$}{kWh}\right) = ICAP\left(\frac{\$}{kW}\right) * \frac{\exp\left(\frac{-(\mathrm{P} - L_t)}{m}\right)}{\sum_{t=1}^{N} \exp\left(\frac{-(\mathrm{P} - L_t)}{m}\right)}$$

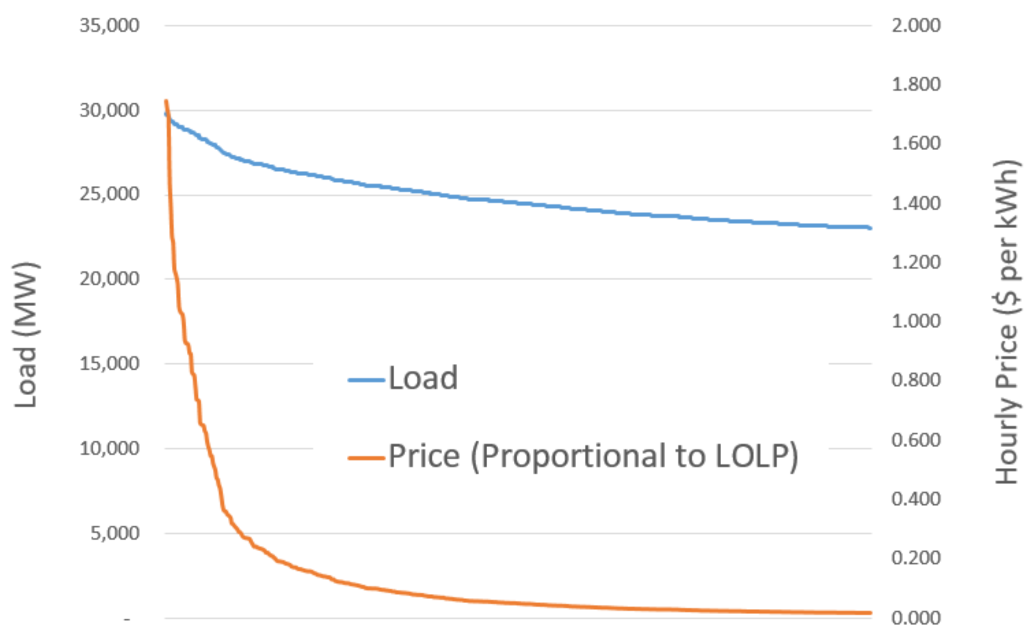
[35] Called the "Garver Approximation Method," described in Madaeini, S., et. al., *Comparison of Capacity Value Methods for Photovoltaics in the Western United States*, July 2012, NREL/TP6A20-54704.

Or,

$$Price_t(\frac{\$}{kWh}) = ICAP\left(\frac{\$}{kW}\right) * \frac{\exp\left(\frac{-(\mathrm{P} - L_t)}{m}\right)}{LOLE}$$

Figure 3 shows the top 600 NYISO hourly loads for 2014 and corresponding hourly prices, calculated using this method with m assumed to be 5% of peak load[36] and the same \$100 per kW-yr is assumed as in the previous example. The range is significantly different than the proportional load method, with a minimum price of zero (rounded) and a maximum price of \$1.75 per kWh. On the low end, 40% of the hours per year have prices below \$0.001 per kWh, but on the high end, the top 600 hours have an average price of \$0.14 per kWh and the top 100 hours have an average price of \$0.56 per kWh. This spread of pricing could potentially result in adoption of new DER technologies—and support their more effective dispatch—as compared to the proportional method or the use of TOU rates. For this reason, we favor this approach.

Figure 3. Top 600 Hours of 2014 NYSIO Load and Hourly ICAP Price (Illustrative).



[36] The example results are highly sensitive to m, so additional work is recommended in order to define a suitable method for determining the value of this parameter.

Avoided Energy (LBMP)

Avoided energy prices are developed from the LBMPs as described in the BCA Framework. To use these LBMPs (or actual LBMPs that follow from the market clearing prices), the hourly price of avoided energy is simply the LBMP.

The BCA Framework describes the use of energy price forecasts from CARIS. The CARIS cost forecasts would be applicable in a study for calculating value provided by a time-aligned production profile. The proposed approach follows the intent of the BCA Framework by basing marginal energy costs on LBMPs, however, it differs from the BCA Framework in that it assumes actual LBMPs for settlement purposes, rather than forecasts.

Avoided Transmission Capacity Infrastructure and O&M

The existence of this benefit as described in the BCA Framework is dependent on whether there are values provided "beyond that which is included in the ICAP price and LBMP."[37] If so, these should be expressed as annualized costs (in $ per kW-year) and converted to hourly prices using the same method described for ICAP, above.

Avoided Transmission Losses

If included, these should be monetized using the same method as Avoided Distribution Losses as discussed in that section below.

Avoided Ancillary Services

Potential Ancillary Services provided by DER, as described in the BCA Framework, include spinning reserve, frequency regulation, voltage support, and VAR support. Tariffs for Ancillary Services provided by DER would be applicable for those projects that provide such services.

Wholesale Market Price Impacts

The BCA Framework describes the use of the most recent CARIS database to estimate wholesale energy market price impacts of a 1% change in the level of load requirements. This approach means that the estimated increase in marginal price for a given pricing node and for a given hour would be computed as follows:

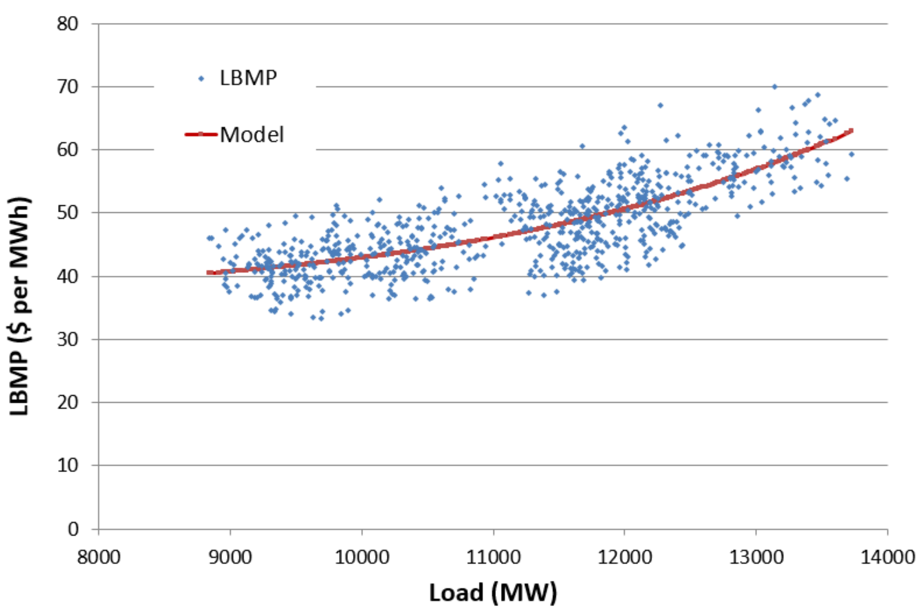
[37] BCA Framework, p. 6.

$$\frac{\Delta LBMP}{\Delta Load}\left(\frac{\$/kWh}{kW}\right) = \frac{LBMP_{Load+1\%} - LBMP_{Load}}{0.01 * Load}$$

This calculation could be performed for every hour when resolving bill amounts. As a practical consideration, however, it would be simpler to perform an analysis on historical data (or CARIS-derived results) and to develop a mathematical model, such as the one illustrated in Figure 4. The model shown (red curve) is a simple exponential curve fitted to pricing data for a given month (e.g., all prices for January). Each point represents actual clearing prices and loads, and the presentation illustrates the range of LBMPs that would be expected in a given month at any given load.

The key objective of this modeling exercise is to obtain a reasonable function for pricing as a function of load. It is not useful to develop a forecasted price versus time model or forecasted market price response versus time model because it could not be applied to DERs with uncertain dispatch patterns. This approach aims to develop a method that can be applied retroactively at bill settlement.

Figure 4. Model of LBMP Versus Load (Illustrative)



Once such a model is developed, the above equation can be applied to the model itself, yielding the slope of the model at any given load based on an incremental change of 1% of load. To apply this in calculating the hourly LMP+D tariff compensation, a procedure similar to that in Table 3 would be used.

Table 3: Sample Calculation for Wholesale Market Price Impacts (hour ending 2:00 pm, January 12. Load is 10,000 MW. DER output is 4.3 kWh)

Step	Description	Sample Calculations
1	Determine the load during the hour to be compensated.	10,000 MW
2	Apply the equation above to determine the slope of the model at the load	ΔLBMP/ΔLoad @10,000 MW = ($42.2/MWh - $42.0/MWh) / (10,100 MW – 10,000 MW) = $0.002/MWh per MW
3	Calculate the total savings in the hour	Savings = $0.002/MWh per MW x 10,000 MW = $20 per MWh = $0.02 per kWh
4	Apply rate to DER production	Compensation = 4.3 kWh x $0.02 per kWh = $0.086.

Avoided Distribution Capacity Infrastructure

Introduction

The BCA Framework identifies a number of critical factors that must be considered in evaluating the economic benefits of DER associated with distribution capacity infrastructure. These factors include costs that are dependent upon location (rather than total costs across a service territory), coincidence with location-specific loads (rather than NYISO loads), and the availability of excess local capacity.

Geographical Resolution

To reflect location-specific differences in value, the costs and technical impacts must be evaluated for defined geographical (or electrical) regions. "Planning areas" must be defined by the utilities corresponding to their existing practices. For example, all loads served by a group of specific substations would be identified, and a geographical description of these planning areas made public in sufficient detail as to make it clear which customers reside in which area. Then, the utility would be responsible for tracking historical and ongoing expenditures by planning area and calculating DER charges and credits by planning area.

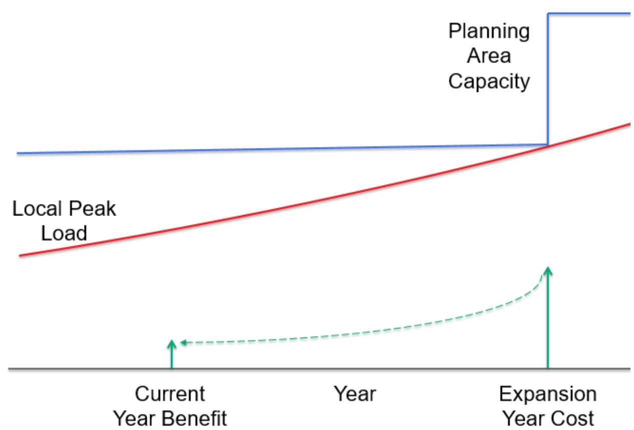
Operational Control of DERs

In extending BCA Framework Order principles to develop DER rates, an additional factor comes into play: DERs will not be controlled by the utility. They may be controlled by a customer or by an organization or DER provider representing the interests of an aggregation of customers (shared resource provider). This is more complex than the example of the 1 MW battery (BCA Framework Order, Appendix C, page 9) insofar as the output profile is determined by the customer. For this reason, the compensation is based on actual performance rather than planned operating schedules.

Timing of Distribution Investments

The BCA Framework Order further indicated that one factor in determining value is the "amount of available excess capacity" on the system. In planning areas having significant excess capacity, there is little capacity benefit provided by DER in reducing peak loads. In areas with little available margin, on the other hand, properly timed DER could make the difference between the utility committing to an investment and the utility deciding to defer or cancel an investment. The principles are illustrated conceptually in Figure 5, in which growth in peak load is anticipated to reach maximum planning area capacity in a future year, triggering the installation of new capacity. The benefit of avoiding the new capacity depends on both the cost of the new capacity as well as the planning time horizon. The potential benefit of avoided capital costs must be discounted to present worth, so a technical estimate of the timing of expenditures is also an important input. The timing may be driven either by load growth, as illustrated in the figure, but also by equipment retirement.

Figure 5. Load Growth, Planning Capacity, and the Discounting of Future Costs.



Non-capacity Investments

Distribution investments are not only made on the basis of required capacity, but may also be made on basis of other considerations such as reliability, safety, or other needs. For example, a utility may convert an overhead circuit to underground construction for visual aesthetics or to reduce exposure to outages (improved circuit reliability). A new circuit could be built in order to provide flexibility to deliver electricity while other lines are being maintained. To the extent that these costs cannot be avoided by DER, these would not be included in the LMP+D calculation.

The proper differentiation between these unavoidable costs and capacity-related costs is therefore important to both ensuring that the utility is able to recover costs and ensuring that DER is able to realize compensation for the benefits it provides.

Identifying Capacity-related Costs

In some cases, the differentiation between unavoidable costs and avoidable capacity-related costs is more complicated. Capital expenditures for substation upgrades are an example of capacity-related costs, and DER has the potential to avoid these costs. At the other extreme of the distribution system are the secondary conductors terminating at the customer's service entrance. The costs may be considered "fixed" because they are not avoidable by DER and, in fact, DER exports depend upon them.

Between the substation and the secondary conductors are a variety of other lines, some of which potentially represent capacity that could be deferred through DER. A circuit-specific engineering analysis might indicate, for example, that a given DER would deliver energy to selected customers in its vicinity and also reduce the loading on the main feeder. The wiring between the DER and the customers it served would not be avoidable by the DER because this wiring is necessary to deliver the DER energy.

On the other hand, the analysis might indicate that peak loads on the main feeder is supported by aggregations of DER. If so, we would conclude that the main feeder line is a capacity-related cost that should be included in the LMP+D variable rates.

However, the engineering analysis described above would be highly circuit-specific and it may not be practical to perform such an analysis on every circuit as an input to the rate design, particularly for the interim methodology. The analysis results might change as loads are transferred between substations. The analysis results might indicate that only a portion of the feeder, say, the first three quarters of a mile of the feeder, is actually capacity-related, while the remainder of the feeder is not. It would also not be practical for the utility to have to identify individual line sections as either "variable" or "fixed," especially since DERs are continually being added and the physical demarcation between the two would be ever-changing.

One possible solution to the problem would be to assign representative percentages to capital accounts, depending on purpose. An illustration of this is shown in Table 4, which shows example percentages for each capital account. Station equipment, for example, is shown as 100% capacity-related, while poles and street lighting are not at all capacity-related. Some accounts are partially capacity-related, such as overhead conductors, which are shown in the example to be 25% capacity-related. The actual percentages, which would require additional analysis by the utility and approval by the Commission, would reflect the blend described above, depending on circuit location.

Table 4. Allocation of Capacity Percentages by Account (Illustrative)

Account	Account Name	Additions ($) [A]	Retirements ($) [R]	Net Additions ($) = [A] - [R]	Capacity Related?	Deferrable ($)
	DISTRIBUTION PLANT					
360	Land and Land Rights	13,931,928	233,588	13,698,340	**100%**	13,698,340
361	Structures and Improvements	35,910,551	279,744	35,630,807	**100%**	35,630,807
362	Station Equipment	478,389,052	20,808,913	457,580,139	**100%**	457,580,139
363	Storage Battery Equipment					
364	Poles, Towers, and Fixtures	310,476,864	9,489,470	300,987,394		
365	Overhead Conductors and Devices	349,818,997	22,090,380	327,728,617	**25%**	81,932,154
366	Underground Conduit	210,115,953	10,512,018	199,603,935	**25%**	49,900,984
367	Underground Conductors and Devices	902,527,963	32,232,966	870,294,997	**25%**	217,573,749
368	Line Transformers	389,984,149	19,941,075	370,043,074		
369	Services	267,451,206	5,014,559	262,436,647		
370	Meters	118,461,196	4,371,827	114,089,369		
371	Installations on Customer Premises	22,705,193		22,705,193		
372	Leased Property on Customer Premises					
373	Street Lighting and Signal Systems	53,413,993	3,022,447	50,391,546		
374	Asset Retirement Costs for Distribution Plant	15,474,098	2,432,400	13,041,698		
TOTAL		3,168,661,143	130,429,387	3,038,231,756		**$856,316,173**

Proposed Pricing Method

In addressing the ICAP benefit component, there were two steps to developing hourly prices: first, the total cost was determined based on market inputs, and second, the costs were allocated among hours based on load. The proposed approach for distribution will also require these two steps.

In the first step, determining the total cost based on market inputs, it is important to draw a conceptual distinction between historical (sunk) distribution capital investments, which are not avoidable, and future capital investments, which may potentially be avoidable. The distribution capacity value provided by DER is realized when it serves as a substitute for future expenditures. However, the indicator of cost is based on historically measured costs, just as in the BCA Framework battery example, which used known "marginal costs of the equipment that the load is being relieved from." Therefore, the proposed methodology uses historical costs as a proxy for future cost.

In the second step, allocating costs among hours, the same method may be used. Two alternatives were set forth: one in which price is weighted by load and another in which price is weighted by LOLP. In the case of distribution, LOLP is not a metric used by utilities, but the underlying method of weighting price exponentially by load could be useful for this purpose. The price signals may be more effective than proportional weighting in steering operation of DERs to periods in which they are most effective.

Regardless of the price weighting method selected for this purpose, the load used for weighting should be the local load defined by the same equipment used for the cost input. For example, if the location is defined as a distribution planning region served by three selected substations, the costs for these three substations would be used, differentiated from the costs for other parts of the utility's service territory.

The pricing method, then, is as follows. All of the following steps are performed on the planning area basis.

Step		Example
1	Determine proxy price by dividing the revenue requirement for the planning area capacity-related costs by capacity.	Revenue requirement is \$1M per year and capacity is 50 MW. Proxy price is calculated as 1,000,000 per year / 50,000 kW = \$20 per kW-yr.
2	For each year over 10 years, estimate the capacity-related needs.	Capacity needs estimated as 0 for years 1 to 4, 12 MW for year 5, 0 for years 6 to 9, and 18 MW for year 10.
3	Calculate the present value of the cost of capacity.	Assume discount rate is 7% and escalation is 2%. Present value is: $\$20\,\frac{\left[12\left(\frac{1.02}{1.07}\right)^{5}+18\left(\frac{1.02}{1.07}\right)^{10}\right]}{(12+18)}$ = \$13.7 per kW-yr.
4	Calculate hourly rate using same method as ICAP.	

Avoided O&M Costs

Avoided O&M costs would be calculated as described in the BCA Framework and expressed in \$ per kW-yr for the future capacity additions. This would be added to the proxy price (Step 1 in the example above) and the calculation would follow the same procedure as the capital expenditures.

Avoided Distribution Losses

The BCA Framework indicates that technical losses include both fixed and variable losses. DER will generally only be able to avoid variable losses, and the BCA Framework also describes that these are proportional to the square of the current (I^2R losses). Theoretically, the calculation of avoided losses therefore requires the measurement of resistivity of each conductor on the system, and this would result in different loss factors for every DER location. Other complications also come into play, such as the fact that resistivity is a function of conductor temperature, so hourly ambient convective losses and solar heat gains that also contribute to conductor temperature also have indirect effects on loss factors.

Such a detailed calculation is not practical or desirable, so a simplification is proposed in which all losses in any given hour at all locations are only a function of load in that hour. With this simplification, we may express the losses in hour t as αL_t^2 where L_t is the load and α is the constant of proportionality. Then, we can take advantage of loss study data, such as the data presented in the BCA Framework, Table 3 in Appendix C, that show annual line losses as a percentage of energy delivered. The example, given for energy efficiency, combined transmission and distribution loss percentages into a total percentage of 4.14%. This percentage may be generalized into the parameter p and, by definition,

$$p = \frac{\sum \alpha L_t{}^2}{\sum L_t}$$

Where the summations are for every hour of the year. From this we solve for α to get:

$$\alpha = p \frac{\sum L_t}{\sum L_t{}^2}$$

This equation allows us to determine α based on the loss percentage p taken from the loss study, and the hourly loads over a given year. This allows us to dynamically (i.e., hourly) calculate a "gross up factor" (the "loss savings factor") as suggested in the BCA Framework as follows. If the energy delivered as an output of the T&D system in hour t is $E_{delivered}$, then the input energy is given by:

$$E_{\text{input}} = \frac{E_{delivered}}{(1 - \alpha L_t^2)}$$

The loss savings factor for hour *t* is therefore:

$$LSF_t = \frac{1}{(1 - \alpha L_t^2)}$$

Loss savings factors (LSFs) would be calculated for each hour and applied to the prices for each component. Separate loss factors would be calculated for only those components that provide loss savings to the distribution system (e.g., Avoided Distribution Capacity Infrastructure) and those that provide both loss savings to both the distribution system and the transmission system. The procedure would be the same, but the percentage loss p would be different.

Loss savings apply to all of the other benefits and costs which have an associated hourly price. The methodology could therefore include one of two procedures: (1) calculate loss savings factors individually for each benefit, and multiply each component price by its associated LSF to obtain the adjusted component price; or (2) create a separate additive price to represent Avoided Distribution Losses (ADL) as follows:

$$Price_{ADL} = (LSF_1 - 1) \times Price_1 + (LSF_2 - 1) \times Price_2 + (LSF_3 - 1) \times Price_3 + \cdots$$

Externalities

Emissions impacts depend on the load in a given hour because the mix of generating resources change with different load levels. As a practical matter, technical and cost impacts could be modeled for a year to obtain the cost in $ per kWh of each pollutant at each load level. The hourly price would then be set dynamically based on the load in each hour. As described in the BCA Framework, DER technologies that emit pollutants would have their externality benefits adjusted, depending upon the emissions profile for each technology.

Costs

Program Administration Costs

Program administration costs are not required to be included in the LMP+D rate because DER would be compensated (either through bill savings or bill crediting) using the utility's billing system. Any additional costs that may be incurred in developing new billing computations or in calculating new hourly billing rates would apply equally to consumption and production and should therefore by treated as costs shared by all customers.

Added Ancillary Service Costs, Incremental T&D Costs

These costs are also necessary to meet REV objectives of clean energy and so should be included as energy-denominated costs applicable to all customers.