July 24, 2017

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TO:
Honorable Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
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FROM:
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RE: CASE 15-E-0751 Regarding the VDER Phase 1 Implementation Plans of the Joint Utilities

Dear Secretary Burgess,

Please find the comments of the Solar Energy Industries Association, Vote Solar, the Coalition for Community Solar Access, Pace Energy and Climate Center, the Natural Resources Defense Council, and Acadia Center (the Clean Energy Parties), on the Phase 1 Implementation Plans of the Joint Utilities.

Sincerely,

/s/ Richard Umoff
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Value of Distributed Resources Phase One Implementation Plans
Comments of the Clean Energy Parties
Case 15-E-0751
July 24, 2017

I. INTRODUCTION

The following comments are submitted by the Solar Energy Industries Association, Vote Solar, the Coalition for Community Solar Access, Pace Energy and Climate Center, the Natural Resources Defense Council, and Acadia Center (the Clean Energy Parties), on the Phase 1 Implementation Plans of the Joint Utilities.[1] The comments were developed with input from Synapse Economics.

The Clean Energy Parties have been engaged in New York's Reforming the Energy Vision (REV) initiative since it began, including the Value of Distributed Resources (VDER) proceeding, and represent a significant portion of the New York clean energy stakeholder community.[2] Broadly speaking, the Clean Energy Parties have been supportive of REV, viewing it is as one of the most forward looking and ambitious reform efforts in the United States with respect to distributed energy resources (DERs). The true promise of REV is to enable a more cost effective, customer centric, and cleaner grid by enabling the proliferation of DERs at high penetration levels, which ultimately will benefit ratepayers, other stakeholders and the State of New York. The REV goals in combination with the Clean Energy Standard, NY-Sun and Governor Cuomo's carbon reduction goals set out an ambitious path to a clean energy-powered future.

[1]1 See Joint Utilities Phase 1 Implementation Plans filed May 1, 2017 (Case 15-E-0751); The comments represent the view of the parties and not any individual member companies.
[2] Id.

The realignment of the utility business model, and the creation of a next-generation DER marketplace, is a central component of REV to create new tools and choices for New York's energy consumers. That new DER marketplace cannot grow and thrive without a properly-structured market. However, at this stage in the process, the Clean Energy Parties are deeply concerned that DERs are being provided insufficient opportunity to compete vis a vis the incumbent utilities to achieve the long term goals of REV.

Clearly, the implementation of Phase 1 is absolutely critical to near term market growth. Thus, we dedicate the bulk of our comments to Phase 1 implementation. However, we believe the broader policy context is important to revisit at this juncture before moving to our recommendations for implementing Phase 1.

One of the key questions in the VDER process is an inquiry into the delivery value of DERs. In its Phase 1 Order, the Public Service Commission (PSC) recognized that DERs have significant delivery value, but that this value has yet to be fully identified and realized. In the short run, the PSC identified two delivery values as proxies for the Phase 1 Value Stack – demand reduction value and locational system relief value. Demand reduction value (DRV) represents the near-term reduction in delivery costs averaged across the delivery system by utility service territory. Locational system relief value (LSRV) represents value in specific locations where forecasted distribution system investments can be avoided.

While DRV/LSRV may be viewed by the Commission as necessary near term measures to begin the process of identifying delivery values, these values are wholly inadequate as they are too unpredictable to support near term investment in DERs, and they fail to capture the delivery value of DERs in the long term. DRV/LSRV are based on near and medium-term marginal costs that fail to fully account for the value of DERs over their useful life, and are insufficient to support deployment of DER at scale to achieve the goal of a DER centric delivery system. Further, the approach taken by the utilities to calculate DRV/LSRV based on narrowly identified avoided costs belies a central problem that REV seeks to reform – the natural impulse of the monopoly distribution company to discriminate against DERs to protect its incumbency.

In its Track One Order, the Commission laid out its vision for REV. Central to this vision is the notion that DERs should be enabled to compete with distribution companies through the regulatory reforms of REV, and become more central to the distribution system. The Commission says:

> REV will establish markets so that customers and third parties can be active participants, to achieve dynamic load management on a system-wide scale, resulting in a more efficient and secure electric system including better utilization of bulk generation and transmission resources. As a result of this market animation, distributed energy resources will become integral tools in the planning, management, and operation of the electric system. **The system value of distributed resources will be monetized in a market, placing DER on a competitive par with centralized options.** Customers, by exercising choices within an improved electricity pricing structure and vibrant market, will create new value opportunities and at the same time drive system efficiencies and help to create a more cost-effective and integrated grid.[3]

To achieve this vision, the Commission identifies two major reforms that are needed. First, the Commission identifies the current utility regulatory system as problematic as it encourages utility capital deployment:

> **The current regulatory system places a premium on capital deployment.** In contrast to competitive firms that are damaged by low rates of capacity utilization, utilities under traditional rate of return regulation are indifferent as to whether the rate of capital utilization is efficient.[4]

Relatedly, the Commission identifies the utility's natural bias against DERs, and the need to move towards a utility model that encourages DER deployment.

> Under the present regulatory model…distributed energy competes with the standard methods of supplying and delivering power. **The opportunity before us is to set forth a regulatory and business model for the traditional utility and its investors that prompts *encouragement* of this form of competition, rather than opposition.** In

[3] Track One Order at 11
[4] Id. at 19

> doing so, we can avoid the inefficient use of capital that occurs from innovation and competition.[5]

Thus, REV envisions a future in which the regulatory model incentivizes the utility not to only build delivery system capacity through major infrastructure investments, but rather to develop a platform that encourages DER deployment to serve this need more cost effectively and in a manner that achieves other policy objectives. To achieve this goal, the regulators must go beyond developing a market that values DERs on a marginal short term basis, but rather identify and correct the inherent bias in the utility business model by taking steps to put DERs on equal footing with the distribution companies.

In a restructured market, such as New York, there is an opportunity for generators to compete for services where competitive markets exist. In the case of New York, these are wholesale energy and capacity markets, wholesale ancillary services, and retail energy markets. However, organized markets are not available at the distribution level to compete for distribution system investments and services that are currently only provided by the distribution companies.

In this context, placing DERs on equal footing with the distribution companies does not mean merely providing short term marginal prices to DERs as determined by the utilities every few years, but rather affording DERs the same treatment as the monopoly against which DERs compete to provide distribution services. So long as the distribution companies can forecast, finance, plan and receive cost recovery for distribution system investments over a long horizon, such as the life of the asset, while DERs are expected to finance and invest based on short term marginal price signals, DERs will be at a severe competitive disadvantage and the system will be biased towards utility investments. This will impede progress towards the Commission's long term goal of enabling a transactive grid that unlocks new revenue streams for the distribution companies that is ultimately needed to shift their role from distribution service providers to platform service providers.

[5] Id.

And, while the development of organized competitive markets for such services may be a long-term goal of REV, development of markets that offset major delivery system needs based on short run marginal prices relies on high penetration DERs, which cannot be developed in the long term so long as DERs are at a competitive disadvantage in the near term.

For the delivery component of the rate, DERs are not competing with competitive generators to provide products and services subject to market forces, but rather with monopoly utilities to provide long lived infrastructure investments. This is an entirely distinct type of investment by an entirely distinct type of market actor, which should be reflected in the delivery component of the rate. The delivery value should reflect the same forecasting used by utilities to determine system needs, the same avoided costs associated with distribution system needs, and use the same timelines afforded utilities to plan, finance and receive cost recovery for their distribution system investments. Further, the delivery value should reflect all costs associated with the delivery system that DERs can offset, not just those directly related to load growth. It is only by ensuring this symmetrical treatment of utilities and DER providers for providing delivery services that a ubiquitous DER market can begin to develop, and utilities can begin the shift from distribution company to platform service provider.

Finally, further compounding this issue, is the fact that the utilities have the data needed to identify these avoidable costs and to build out tariffs that enable the monetization of DER functionality. It is much harder to design customer products and finance projects if there are key values that are unpredictable, irretrievable, or subject to utility interpretation. It is natural that the incumbent is disinclined to provide this data. However, it is imperative that the relevant data be provided, and that it be done in a format that allows stakeholders sufficient opportunity to review and challenge the data and assumptions put forward by the distribution companies. Failure to provide this opportunity is tantamount to expecting the incumbent to willingly give up its incumbency.

Below are the Clean Energy Parties' specific recommendations for Phase 1 implementation:

a. Near Term Actions to Ease Implementation and Reduce Soft Costs

i. Authorize an increase in CDG project size to 5 MW.

ii. Direct the utilities to implement automated billing measures, and allow for optional consolidated billing, as soon as practicable.

iii. Reduce the minimum CDG subscription size.

b. Mechanics for Crediting Projects for MTC and Value Stack

i. Direct the utilities to adopt Staff's "Alternative 1" for MTC allocation.

ii. Clarify CDG credit banking and allocation practices.

iii. Allow the CDG project owner to elect whether DRV/LSRV value is credited to the project owner or the bill subscriber.

iv. Remove load zone restrictions for CDG subscribers

v. Direct the utilities to correctly implement hourly netting

c. Value Stack Methodology

i. <u>Direct the Utilities to Recalculate the MTC Based on Updated Value Stack Inputs</u>

ii. <u>Clarify That Projects Will be Placed on a Tariff that Appropriately Values DERs after the Phase 1 Tariff Runs its Course</u>

iii. <u>Environmental Value</u>

1. Clarify that the environmental value is based on the REC price at the time a developer makes the 25% interconnection payment

iv. <u>Capacity Value</u>

1. Adjust "Alternative 2" to Meet the Letter and Intent of the March 9 Order to Provide a Strong Incentive for Solar/Solar+Storage

2. Direct National Grid, Orange and Rockland, and ConEd to Correct their Service Class Selection for Capacity

v. Delivery Value

1. **Demand Reduction Value (DRV)**

    a. DRV and LSRV methodologies must use previously approved full MCOS values and DPS should deny proposals for untested and unreviewed methodologies that artificially limit the values used.

    b. Proposed methodologies for calculating DRV and LSRV should be fixed for the duration of the Phase 1 tariff.

    c. Reducing DRV or LSRV value to "share" savings is contrary to the Commission's order and biases system in favor of utility infrastructure investments.

    d. Any allowed changes to MCOS methodologies must be applied consistently to other utility requests for cost allocation and recovery.

    e. The 50% stretch methodology for determining DRV and LSRV compensation appears reasonable.

2. **Locational System Relief Value (LSRV)**

    a. Methods must be used across all utilities for identifying LSRV zones and determining MW caps that are consistent with utility practices for new infrastructure upgrades and identified on a ten-year planning horizon.

    b. Compensation should be locked in at the execution of interconnection agreement, should not be retroactively adjusted, and should be available beyond the initial ten year term.

    c. MW caps should be technology neutral and apportioned to eligible projects based on expected coincidence with the relevant peak

II. DISCUSSION

a. NEAR TERM ACTIONS TO EASE IMPLEMENTATION AND REDUCE SOFT COSTS

In the following section, the Clean Energy Parties put forth actions the Commission should take to help reduce soft costs and drive market development in the near term.

i. Increase Project Size to 5 MW

We reiterate our support for increasing the project size maximum eligible to participate in the VDER Phase 1 tariff from 2 MW to 5 MW.[6] Under the current net metering rules, larger distributed generation projects can already be co-located on adjacent parcels, such that their effective size is larger than 2 MW.[7]

Thus, increasing the maximum project size above 2 MW would have little to no impact on the potential costs to ratepayers, effective total size of projects in a community, nor on the effect of DERs on the grid. This change would, however, result in incremental cost savings to DER providers, reduced administrative burdens on utilities, customers, and DER providers, and could make the difference for marginal projects that might not otherwise be built. On average, we estimate that an increase in maximum project size to 5 MW or above would reduce the per-MW costs of deploying distributed solar in New York by 2.5% - 4% -- saving hundreds of thousands of dollars in otherwise duplicative or otherwise unnecessary costs.

Specifically, increasing the maximum project size under VDER to 5 MW or more would reduce redundancy and project costs in at least the following ways:

- Increasing project size above 2 MW would allow for consolidation of interconnections, resulting in fewer physical interconnection points. This change would reduce the need for redundant costs associated with equipment, labor, and facility design.
- Consolidating several 2 MW projects into a single array would allow for a more efficient site layout and reduce capital and operations and maintenance costs in categories such as vegetation management and fencing.
- Increasing the maximum system size would reduce administrative overhead in categories such as lease negotiation (fewer leases required), surveying and subdivision, recording

[6] See the Clean Energy Parties' April 17, 2017 comments in response to the April 5th technical conference.
[7] Case 14-E-0151 and Case 14-E-0422, Order Raising Net Metering Minimum Caps, Requiring Tariff Revisions, Making Other Findings, and Establishing Further Procedures, issued December 15, 2014

fees, corporate registration fees, due diligence, legal fees and other such categories of cost.

Increasing system size would also reduce the burden on utilities associated with managing multiple 2 MW interconnection requests and multiple host customer accounts per co-located site, i.e. for a 5 MW project under today's regime three host customer accounts are required. Ultimately, the CDG participants will also experience the benefits through more options and opportunities for participation. In other words, increasing the maximum project size should be a clear win for all stakeholders.

There are examples where larger CDG projects are being developed but are incurring these additional soft costs in order to meet the existing 2 MW project size cap. Project developers have indicated through filed comments and at the technical conference that they are subdividing parcels in order to meet the 2 MW limit, but that when taken together, these individual projects are effectively larger CDG projects.[8,9] And, public project announcements further demonstrate this approach.[10]

For these reasons, we strongly support increasing the maximum project size under the VDER Phase 1 tariff to at least 5 MW. In addition, we note that the savings discussed above would be even more pronounced if the Commission were to increase the maximum size to, for example 6 or 8 MW AC—in line with the effective size of most larger (subdivided) commercial-industrial scale solar projects in New York today.

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[8] See the SUN8 PDC LLC ("SUN8") petition filed on June 9, 2017. SUN8 describes two projects, the "Middlesex Project" and the "Ellis Project", which total 3.7 MW and 12 MW respectively. As described in the petition, SUN8 is sub-dividing the tax parcels upon which these projects are to be constructed in order to meet the 2 MW project size limitation.

[9] At the April 5, 2017 technical conference, Cypress Creek explained that they are also siting multiple 2 MW projects side by side.

[10] Via its public project statement, Blue Rock Energy announced that it has received special use permits for its 4.4 MW-DC community solar project from the Town Board in Grand Island. See *Approval granted for New York's largest community solar project*, Christian Roselund, PV Magazine, July 10, 2017. Online: https://pv-magazine-usa.com/2017/07/10/approval-granted-for-new-yorks-largest-community-solar-project/

1. Recommendation for a One-Time Consolidation Option for Adjacent Sequential Projects Currently in the Interconnection Queue

Should the Commission allow projects larger than 2 MW to qualify for the VDER tariff, we believe it is also appropriate to allow current interconnection applicants to consolidate multiple adjacent projects in the same interconnection queue on a one-time basis. Specifically, any projects located on the same or adjacent parcels whose interconnection applications are sequential in the same queue should be allowed, on a one-time basis, to consolidate their applications into a single application, subject to the size limit adopted by the Commission. Projects in the interconnection queue as of the date of adoption that have not yet paid for 100% of their interconnection costs[11] would be authorized to consolidate multiple applications, subject to the requirement that the combined size of the projects cannot exceed 1) the revised size threshold for VDER projects, or 2) the combined capacity of the applications to be consolidated. Applicants would be required to withdraw all but one of the consolidated interconnection applications from the queue, so that each applicant's total capacity in the queue would remain the same and there would be no adverse impact on other applications in the queue behind the consolidated projects. Any additional studies or interconnection costs required following the consolidation would be the responsibility of the applicant. However, the utilities should be directed to limit, to the extent possible, the scope, cost, and length of any restudy or redesign required to implement the consolidation.

This proposal would allow the Commission's decision to increase project size (if adopted) to go into effect immediately for projects currently in the planning and design stage. Given the number of projects in the queue today, applying the decision to projects in the queue is the only way to ensure the benefits of this change can be realized during Phase 1. This policy would yield immediate benefits to the DER community, customers and the utilities by reducing the cost of interconnection for larger projects and by reducing the administrative burden on utilities,

[11] Payment of 100% of interconnection costs is typically the step in the interconnection process at which the utility is able to begin procuring equipment to complete the interconnection. Prior to this step, no physical work on interconnection will have begun.

customers, and project owners that is currently imposed by the necessity of breaking up larger projects into several points of interconnection. Because interconnection applicants alone would bear any added costs associated with a restudy or redesign of the interconnection, this proposal would not impact ratepayers or the utilities. Therefore, we strongly recommend that the Commission adopt this consolidation policy at the same time that the Commission issues its decision on the possibility of increasing the VDER project size.

ii. Direct the Utilities to Implement the Following Billing Measures Immediately

1. Automation of Bill Credit Calculation, Application, and Data Exchange

The proposals to manage bill credit calculation and application contained in the utilities' May 1 implementation proposals are wholly inadequate for effectively serving customers and supporting a functional CDG market. CDG cannot succeed in New York unless the utilities have an efficient and error-free means of:

1. Accepting subscriber lists from CDG hosts
2. Calculating bill credits and applying them to subscriber bills
3. Communicating in a clear and timely fashion with CDG hosts and customers regarding credits applied

We urge the Commission to place greater emphasis on getting systems in place that can accomplish the above. Relying on and expecting utility staff members to email files containing subscriber lists and credit calculations back and forth for each CDG facility on a monthly basis is not an appropriate or efficient means of serving customers, scaling the CDG market in New York, or building toward the REV goal of enabling more efficient transactions at the distribution system level.

The systems proposed by the utilities would lead to frequent mistakes in credit calculations and delays in applying credits to customers' bills. This would seriously damage the initial customer experience with community solar and with solar more broadly, since community solar represents the only opportunity for the majority of customers to participate directly in the clean energy economy in New York. The added costs associated with an inadequate approach cannot be underestimated. Utilities, CDG providers and Staff will experience a surge of customer inquiries and complaints if automated processes are not implemented.

Efficient, automated bill crediting is not simply a "nice to have" feature. It is essential to enable CDG providers to do business in New York at any meaningful scale. Timely and accurate recognition of revenue is the core function of CDG businesses, just like any other business. If CDG providers are not able to recognize revenue they will ultimately fail. Most CDG providers obtain revenue by collecting subscription fees from participating customers. If those customers are not receiving timely and accurate bill credits, and if the utility does not communicate with the CDG hosts regarding the amount and timing of credits applied, then the CDG host cannot properly collect subscription fees. Challenges with bill crediting in other states have led to CDG providers being forced to delay collection of millions of dollars in subscription fees, so as not to charge customers for a product they are not yet receiving as a result of utility failure to properly apply bill credits. Beyond the unacceptable impacts on individual customers, this threatens the financial viability of the CDG projects and creates concern within the financing community that the revenue from CDG projects is unreliable. The Commission must firmly establish that efficient, automated bill crediting processes are required to enable CDG in New York.

There are currently ~310 MW of CDG reserved in the VDER tranches.[12] If one assumes 100% residential participation and 7.5kW average subscription size, that represents over 40,000 subscribers for which utilities will need to manage bill credit calculations and applications. Presuming DPS and NYSERDA will, as directed by the Order, successfully seek means of supporting CDG development in utility territories where economics are currently particularly

[12] NYSERDA Phase One Tranches for Community Distributed Generation Projects Allocated Capacity per Tranche (MW AC) chart, https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Project-Developers/Value-of-Distributed-Energy-Resources, updated July 1, 2017.

challenging, the number of CDG projects and subscribers under VDER Phase 1 is likely to increase beyond 40,000.[13]

Utility difficulty implementing bill crediting should not be a reason to limit CDG development; to the contrary, utilities should be required to make adoption of efficient bill crediting systems and effective automatic communications with CDG providers a priority in order to enable the state to make meaningful progress toward the equal access envisioned by the Commission's initial July 2015 Order establishing CDG in NY.[14]

We outlined the functionality required for an efficient CDG program that best serves customers, CDG providers, utilities, and regulators in our April 17 comments to inform the utilities' May 1 filings, based on CCSA members' extensive experience in other states (See Appendix). Unfortunately, the utilities' May 1 filings did not acknowledge that we provided our expertise or recommendations on this important point and failed to adopt our recommendations. We re-emphasize the necessity of such functionality, and reattach our recommendations in the Appendix.

Multiple utilities have mentioned that their IT departments are stretched thin and cannot dedicate enough time to build automated crediting and allocating functionality within the next 12-24 months.[15] For this reason, and to ensure greater consistency in customer experience and service quality across the state, we recommend that NYSERDA issue an RFP for a third party administrator to manage bill credit calculation and allocation for the utilities and enable effective transparency regarding those calculations and allocations. We expect this to result in lower cost and more effective solutions that can be implemented at the pace necessary to accommodate the CDG development anticipated under VDER Phase 1. A more standardized statewide solution,

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[13] See March 9, 2017 Value of Distributed Energy Order, starting page 142.

[14] See July 17, 2015 Order Establishing a Community Distributed Generation Program and Making Other Findings, NY Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program.

[15] Central Hudson, National Grid, NYSEG and RGE all mention these long timelines in their May 1, 2017 Implementation Plans compliance filings.

customized to interface with each utility's IT system, would also enable a standardized interface for CDG providers operating across multiple territories, which would result in lower soft costs for developers and improved customer experience.

Should the Commission decide not to direct issuance of an RFP for a third party administrator, we recommend the Commission at minimum order and track the implementation of the three priorities discussed above, and establish a Phase 1 Implementation working group of individuals from utility billing departments and CDG providers that meets every two weeks until the utilities have launched billing solutions that adequately meet the needs of customers, CDG providers, and regulators.

One area of focus for this working group, though not the only task, must be on developing standardized and automated communication between the utilities and the CDG providers to provide transparency on credit calculations and allocations. As an initial starting point, we recommend that the Commission require the utilities to provide, within a set period of time immediately following a billing period, reports communicating, at a minimum, a table with the following information per CDG subscriber:

- Customer Name
- Customer Account Number
- Current Percentage Allocation
- Bill credit received this period ($)
- Electric bill this period ($)
- Excess bill credit ($)

This communication from utilities back to CDG hosts is particularly critical given the complexity of the VDER tariff, which will make it more difficult for CDG hosts to accurately calculate bill credits on their own and charge customers accordingly. For example, if a CDG provider is offering a fixed-discount product, where the subscription fee to the customer is set at a fixed percentage discount to the credits received, the CDG provider must be confident in the value of credits a customer receives in order to properly charge that customer for that month, and the customer must have transparency into the crediting calculations in order to have confidence in the DER market.

ORU and ConEd stated in their May 1 implementation proposals that they intend to communicate monthly back to CDG hosts regarding bill credits applied. However, the Commission must require all utilities to communicate this information in a timely and <u>automated</u> fashion in order to enable CDG providers to conduct their side of the business appropriately, and avoid the unacceptable, reactive approach in which utilities and/or CDG providers assume the credit calculations and allocations are being applied correctly until they hear otherwise directly from customers. CDG providers have experienced very troubling situations in other states where utilities have not provided bill credits for an extended number of months, yet the lack of transparency in the process prevented the CDG provider from being able to effectively intervene in the situation or assist the customer in obtaining credits due.

2. <u>Consolidated Billing</u>

We reiterate that consolidated billing represents an important opportunity to improve the customer experience and reduce soft costs associated with CDG. We encourage the Commission to require utilities to offer consolidated billing <u>as an option</u> for CDG providers. Recognizing that a purchase of receivables structure may be more difficult to implement, we believe a simpler on bill repayment structure is an appropriate step at this time. Under the latter, the utilities would collect customer payment for subscriber fees, and remit those payments to the CDG provider, less any processing fee charged by the utility. Under an on-bill repayment structure, clear payment priority rules must be developed to address how collection for non-payment (and partial payment) will be handled. It is important to develop priority rules that are designed to optimize the customer experience. It should be noted that Oregon Public Utilities Commission (OPUC) recently approved an on-bill repayment model in its Order adopting community solar program rules.[16]

iii. Reduce the Minimum CDG Subscription Size

The July 2015 Order initiating the CDG program set forth a minimum subscription size of 1000kwh per year. Based on the evolution of the market since that point, the Joint Parties recommend reducing the minimum subscription size to 250kwh per year (approximately one solar panel's worth of generation per year). This relatively minor policy change will enable greater consumer uptake of CDG by allowing customers with very low usage to participate and allowing customers to offset smaller increments of their energy bills with CDG; this could also spur consumer-friendly business model innovations in line with REV objectives. It could make it easier for customers, in particular residential customers and LMI customers, to enroll in community solar and receive savings on their electric bills. Providing greater flexibility in community solar subscriptions allows for easier bundling of community solar with other energy programs, thus accelerating customer involvement in energy choices (a REV goal) and adoption of community solar.

b. MECHANICS FOR CREDITNG PROJECTS FOR MTC AND VALUE STACK

i. Direct the Utilities to Adopt Staff's "Alternative 1" for MTC Allocation

The only viable approach to calculating and allocating the MTC under the Order as written is the "Alternative 1" approach put forth in the presentation filed by Staff on April 14, 2017. Under Alternative 1, each subscriber receives bill credits calculated specific to their customer class, and those credits do not change in the event of changes to the overall subscriber composition of the project.

[16] Docket AR 603, Final Order and Rules, June 27, 2017. Available online: http://apps.puc.state.or.us/orders/2017ords/17-232.pdf

The “Alternative 2” approach would result in credit value to an individual subscriber changing based on changes to the project’s subscriber composition. This would add further complexity and variability to the already complex credit value. It would not be fair to subscribers, would be very difficult if not impossible to manage from a sales perspective, and would be very difficult if not impossible to manage in terms of bill credit calculation, tracking, and allocation. During the June 12 Phase I Technical Conference, Staff expressed a preference for Alternative 1 and at least one utility representative expressed indifference.

Alternative 1 is also the only option that complies with the intent of the March 9 Order to establish CDG credits that are indexed to the subscribers’ retail rate. In other words, because it has created a framework in which the value of a kwh credit depends on the class of subscriber receiving it, the Commission must see that logic through and ensure that residential and small commercial customers receive the full MTC for each of their kwh credits, while demand-billed customers receive the full DRV.

It is important to note that by shifting to a framework in which each kwh generated by a CDG project has the same value – the “machine value” as it has been referred to by Staff – most of the complexity discussed here and in the following section on unallocated credits could be avoided. The Commission discussed the appeal of such an approach leading up to and in the Order, but ultimately decided that a per-class credit approach better approximated retail rate net metering. Now that the complexity inherent in a per-class approach has become more apparent to more parties, the Clean Energy Parties strongly support a return to a framework in which all kwh of CDG generation receive the same value, including an MTC calibrated to the SC1 or SC2 base retail rate. This would result in far simpler bill crediting requirements, would better serve larger commercial customers, and better support the nascent CDG market during this difficult transition from NEM to VDER Phase 1.

ii. Clarify CDG Credit Banking and Allocation Practices

Many CDG projects will generate some level of unallocated credits at any given time, due to customer churn. In the early stages of a project, the percentage of unallocated credits may be higher, as the requirement to interconnect is to have 10 subscribers identified, and hosts have two years to allocate credits to subscriber accounts. Therefore, utilities and hosts will need to track, or "bank," unallocated credits and apply them correctly to subscriber accounts within the two year period, once those accounts are identified by the host. This can be accomplished by tracking the value stack values for each kwh of unallocated generation on an hourly basis, and then once subscribers are identified for the generation, adding either the MTC (in the case of residential or small commercial subscribers) or DRV (for demand-billed subscribers) to the banked value stack credits, and applying the total credits to the subscribers. Because DRV values can change over the life of a project, utilities will need to clearly communicate to CDG providers the DRV value associated with particular credits, so that CDG providers can plan and charge customers appropriately for the credits allocated.

Any approach to credit banking that does not provide an MTC for credits ultimately allocated to residential or small commercial subscribers would be inconsistent with the March 9 Order and with the intent to provide CDG credits indexed to retail rates under VDER Phase 1.

The process for allocating credits banked on the host account must be separate from the process used to allocate monthly generation credits to existing subscribers. CDG hosts will provide subscriber rolls listing subscribers and their respective percentage interest in the CDG array to utilities on up to a monthly basis. Allocation of credits banked on the host account will require separate allocation instructions from the CDG host to the utility.

The requirement to size subscriptions no larger than a customer's annual usage necessitates a thoughtful approach to allocating banked credits. We recommend allowing CDG hosts to allocate banked credits to customers who may not also be receiving credits associated with generation in a given month. This will create more flexibility for CDG hosts to manage banked credits without risking putting subscribers over the 100% of usage threshold.

The tracking of unallocated credits is further reason that Alternative 1 is the only viable approach for MTC allocation. If the value of each kwh were to depend on the rest of the subscriber composition, it would be impossible to correctly value any subscriber's bill credit for a project with any unallocated credits because the total subscriber composition would not be known.

iii. Allow the Project Owner to Elect Whether DRV/LSRV Value is Credited to the Project Owner or the Bill Subscriber

We recommend that the project owner have the option to elect whether DRV and LSRV compensation is provided as a payment to the project owner or a bill credit to the subscriber. As described in the March 9 Order, DRV and LSRV compensation is based on a system's generation during the 10 system peak hours in the previous year. From a CDG provider's perspective, it's important to consider the implications in two scenarios:

1. <u>Crediting CDG Projects Without Storage</u>

There is no way to predict or control performance during the 10 peak hours, therefore it is not possible to plan for or bank on the DRV/LSRV values. Thus, the project will be financed without considering those values, and any value that is received will be upside. That potential upside, if large enough, could be reason for a developer to try to site systems in LSRV zones, but only if there is a viable way for the developer to capture the additional revenue related to the LSRV. If the LSRV is paid to the project owner, that is straightforward. If the LSRV value is provided as a bill credit to the subscriber, the CDG provider faces several challenges including: 1) How to structure a contract such that the subscriber pays the developer for the additional credits when those credits are unpredictable, and 2) Explaining to subscribers that this LSRV/DRV related boost in credits might occur, and ensuring that subscribers would have enough remaining usage on their energy bills to be able to take advantage of the additional bill credit value. These are difficult challenges, especially given the multitude of other challenges created for CDG providers as they try to design products that are financeable and work for customers given the complexity of the new VDER tariff structure. Enabling a payment to the project owner for DRV/LSRV would result in more incentive for developers to site projects in LSRV zones, and less confusion and complexity for subscribers.

2. <u>Crediting CDG Projects with Storage</u>

Because of the DRV/LSRV described issues above and detailed elsewhere in our comments, we do not think it likely that the DRV/LSRV as proposed would be usable for CDG projects and other values like capacity are more likely suitable to encourage storage with these projects. That being said, if the DRV/LSRV value is paid to the project owner, it is possible to see how the project owner could use that revenue to recoup its investment in storage technology (assuming the economics of incorporating storage are viable, which is not at all certain at this time). However, if the DRV/LSRV value is provided as a bill credit to the subscriber, the CDG provider faces the same challenge as with CDG without storage: structuring a reasonably simple and understandable contract that allows the provider to monetize the additional value from the DRV/LSRV, which requires the subscriber to be able to take advantage of the additional bill credit value. Pricing and sizing subscriptions would be very challenging, given that DRV will reset at least every 3 years and the LSRV compensation will end after 10 years. These fluctuations could mean that subscribers would only be willing to sign short-term contracts, which would then make financing even more difficult.

In summary, at this nascent stage of the CDG market, it will be difficult for the DRV and LSRV to contribute meaningfully to the economic viability of CDG projects. They are too complex and too variable for developers to be able to easily and reliably finance projects and design consumer products around them. In contrast, the Commission's approach to the Installed Capacity portion of the value stack allows CDG providers to choose between a more variable and experimental but potentially valuable method (the "capacity tag" approach) and a simpler and less variable method (Alternative 1). Thus, we urge the Commission to adopt flexibility in the mechanism of compensation for DRV/LSRV so that CDG providers can have a clearer path toward capturing these values and can design more consumer-friendly products.

iv. Remove Load Zone Restrictions for CDG Subscribers

The July 2015 Commission order initiating the CDG program set forth a requirement that CDG subscribers be located in the same utility territory and load zone as the CDG facility. It is our understanding that the load zone requirement was initially instituted due to the volumetric retail rate NEM crediting approach of the 2015 CDG order. With the transition to the Phase 1 Value Stack tariff, which compensates CDG subscribers for energy value based on the LBMPs of the CDG facility, there is no longer a reason to require CDG subscribers to be in the same load zone as the facility. We recommend the Commission remove the load zone requirement for all CDG projects on the value stack tariff.

v. Direct the Utilities to Correct Their Use of Hourly Netting

ConEd, in its discussion of metering on page 21 of its May 1 implementation proposal, says that a VDER customer will be required to have an "interval billing meter capable of tracking imports and exports from the customer's premise separately on an hourly basis." Furthermore, ConEd proposes the import channel will be used to calculate charges and the export channel will be used to determine credits. This is inconsistent with the clear terms of the Phase 1 order, which specifies that "net hourly injections" or "net hourly consumption or injection of energy" is the basis for monetary crediting.[17]

Although ConEd may install metering with additional capabilities, the distribution companies should be given clear direction that separate usage of imports and exports within each hour does not comply with the Order and directed to properly use net hourly measurements to determine charges, with the exception of any demand charges calculated on a more granular basis, and credits. Netting exports and imports within each hour is important because it provides a clearer decision principle for customers with load and either storage or generation assets, and the separate measurement of imports and exports within an hour is rarely, if ever, relevant from the perspective of system costs and benefits. As discussed in the order, any customers or developers, who believe that the value of their DER is maximized by separately measuring and valuing generation, are free to do so.

[17] Phase 1 Order at 5, 15; Id. at 73

c. VALUE STACK METHODOLOGY

In the following section, the Clean Energy Parties identify adjustments that should be made to the JU'S methodology for calculating the value stack to ensure that the rate is implemented fully and fairly in compliance with the March 9th Order.

i. Clarify That Projects Will be Placed on a Tariff that Appropriately Values DERs after the Phase 1 Tariff Runs its Course

The residual value of solar facilities following the initial tariff term is important to project financeability. In order to clarify the intent of the Commission and provide appropriate guidance to DER investors, we recommend the Commission confirm in its Phase One implementation order that following the 20 year term of Phase One NEM and the 25 year term of the Phase One Value Stack tariff, projects will be placed on a tariff that appropriately values DERs, reflecting energy, capacity, environmental, and delivery values as well as any additional identified values.

ii. Direct the Utilities to Recalculate MTC Levels Based on Updated Value Stack Inputs

The Clean Energy Parties recommend a recalculation of the MTC levels based on new information that was not initially available at the time of the March 9 VDER Order. The MTC levels estimated in the March 9 Order were based on a value stack that used SC1 as the reference class for Alternative 1 ICAP value. In their May 1 filings, the utilities recommended different references classes for the Alternative 1 ICAP, varying by utility, but none used SC1. The MTCs for each territory should therefore be recalculated using the new ICAP reference classes in the value stack.

On June 30, 2017 Staff filed information and comments supporting this approach and position. As explained in the Staff letter, its assumption from the March 9 Order that the ICAP credit amount for the estimated value stack would be identical to the ICAP charge included in the estimated base retail rate for purposes of calculating the MTCs was incorrect. Instead, as Staff explains, the ICAP credit used in the estimated value stack should be updated and use the 2014-

2016 per kWh average of the ICAP charge for the service class that is ultimately used in the actual value stack compensation.

iii. Environmental Value

1. The Environmental Value Should be Based on the REC Price on the Date the 25% Interconnection Payment is Made

Under the current interpretation of the March 9 Order, the environmental (E) value would be based on the REC price on the commercial operation date, rather than the REC price on the date of on which the 25% interconnection payment is made. This is very problematic because it is out of step with when a project locks in the revenue mechanism and MTC, and is not consistent with Staff's intent.[18] It is critically important that the E value lock at the time of the 25% interconnection payment consistent with other portions of the stack and MTC. Large projects have 12 to 24 month development timelines, 8 to12 months of which can often be after the 25% payment because of utility interconnection construction timelines, permitting timelines, or other factors. To complete all the payments and milestones during the time after which the interconnection payment is made, a developer needs to know how to model the expected revenue from the project. E value is an important part of that revenue. If a developer cannot lock in the E value based on REC price at 25% interconnection payment, they are likely to instead model the Social Cost of Carbon floor, which is much lower than the E value at roughly $0.01. This will make certain projects that would otherwise be viable with the proper E value non-viable. Therefore, consistent with Staff's intent as expressed in its whitepaper, the Commission should clarify that the E value will be set at the time a developer makes its 25% interconnection payment.

[18] Staff VDER Phase 1 Proposal on pg 105

iv. Capacity Value

The Clean Energy Parties support the Public Service Commission's decision to allow DER operators to select between three alternative approaches to valuing capacity. Alternative 2, in particular, represents a useful innovation to encourage non-dispatchable DERs to be designed to maximize their contribution to load reduction during the peak hours of the year. The capacity component of the value stack is critically important to the overall viability of the Phase 1 VDER tariff for both community distributed generation (CDG) and commercial/industrial (C&I) solar projects. In fact, how the two capacity methods are implemented will likely be the key factor in whether both solar-only CDG and C&I projects in many areas, will be viable as the Market Transition Credit declines or disappears. It will also be critical for solar plus storage statewide.

We appreciate all of the work that the utilities have put into implementing the capacity value aspect of the stack in their May filings. However, these filings do not appear to be consistent with the overall intent of the March 9 Order in two key respects. First, the utilities' proposed methodology for calculating Alternative 2 does not appear to be consistent with the Commission's direction and Staff's intent to provide enough additional value to "encourage project siting and design focused on peak summer hours", [19] and to "provide an incentive over the simple monthly average [of Alternative #1]".[20] . Second, several of the utilities' filings do not use an appropriate methods for selecting the service class to be used for capacity Alternative 1. There are also several clarifications needed. Though these issues may appear to have relatively small impacts on the $/kWh compensation rate that DERs can expect under the Phase 1 tariff, the likely impact of these issues on the market for and viability of CDG solar upstate, C&I solar in general, and adding storage to projects statewide is extremely significant.

1. <u>Alternative 2 Should be Adjusted to Meet the Plain Intent of the Language of the March 9 Order and Provide a Strong Incentive for Solar/Solar+Storage</u>

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[19] "Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters", New York Public Service Commission, Case # 15-E-0751, pg 100

[20] "Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters", New York Public Service Commission, Case # 15-E-0751, pg 103

a. The Utilities' Proposed Capacity Alternative 2 Makes Use of a Methodology That Does Not Appear Consistent with the Overall Language of the Order

In its March 9 Order, the Commission summarizes Capacity Alternative 2 as follows: "For this method, each June, the prior 12 months of Service Class 1 monthly capacity statements would be used to determine the $/kW per year. The $/kW/year amount would then be credited to the 460 peak summer hours: hours 14:00 through 18:00 each day in June, July and August. Compensation for the ICAP value would be calculated for kWh generation during those hours, and none during other hours."[21] It also states that this method should provide, "…an incentive over the simple monthly average". [22] Thus, the order's language has the explicit statement that the prior 12 months of capacity statements for Service Class 1 should be used to determine the $/kW/year (the "ICAP value") and that value should be credited to the generator's kWh performance in each of the 460 hours. In conjunction with the language that this method is intended to "provide an incentive over the simple monthly average [of Alternative #1]" the most internally consistent interpretation of this exact language in the order that we can see is to use the average $/kW as calculated over the last 12 months and apply this average capacity value to the solar generator's performance in kWh over the 460 summer hours.[23] The calculation for this is below:

$$\text{AVG}\left(\frac{\text{MCC ECSC}_{\text{Jan}}}{Avg\ kWpeak\ ECSC_{Jan}}, \frac{\text{MCC ECSC}_{\text{Feb}}}{Avg\ kWpeak\ ECSC_{Feb}} \dots\right) \times Total\ kW\ Solar\ Gen\ Over\ 460$$

[21] "Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters", New York Public Service Commission, Case # 15-E-0751, pg 99-100
[22] "Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters", New York Public Service Commission, Case # 15-E-0751, pg 103
[23] Any other interpretation would provide absurd and illogical results. For example, if you summed all the monthly $/kW for the year as opposed to averaging them and applied that to the solar generators average performance in the 460 hours, you would get an incredibly low value that would be less than 4% of the Alternative 1 value. If on the other hand you again summed all the monthly $/kW for the year as opposed to averaging them and applied that to the solar generators total performance in the 460 hours, you would get an unreasonably high value of more than 1800% of the Alternative 1 value (in a sense 460 years worth of cost).

MCC ECSC$_{Month}$ *= The given month's capacity charges in dollars for an example customer in the service class selected*

Avg kWpeak ECSC$_{Month}$ *= The average of the peak power consumption/demand expected per day for the example customer in the service class selected in the given month.*[24]

Total kW Solar Gen Over 460 *= Total kW generated by the solar in the 460 hours, which can be calculated by summing the kWh generation in those hours.*

While we understand that monthly capacity costs are in practice based on a customer service class's share of the utility's contribution during the NYISO system peak hour multiplied by the monthly NYISO capacity price, and are not based on the customer service class's actual expected peak load, we feel this is the best overall interpretation of the order as written given that it is the only interpretation that will provide the above mentioned incentive as desired by the Public Service Commission in their order. In addition to providing the desired incentive for solar to perform in the hours likely to contain times of high demand for the electricity system, our proposed method remains consistent with the order's language to derive an annualized average $/kW over the year using the relevant monthly peak demand of the selected customer class in each month as the denominator of each month's capacity costs. **Please also note that we did not raise this issue in detail beyond one question at the June 12th Technical Conference because we did not have the data until very recently from the utilities to understand the impacts for this methodology choice as they relate to selected customer classes, and we felt it was premature to discuss this in detail until those impacts were accurately quantified.**

[24] Note that in the above calculation that we have used the Avg kWpeak each month for the example customer in the selected service classification to arrive at the monthly capacity cost per kW values that are then averaged. This seems to be the most appropriate metric for this calculation as the average daily peak load reflects the demand these customers are regularly making as a whole on the system and thus represents the required capacity the utility must procure for them on a daily basis in each month. The other options for this calculation are to use the example customer's average kW demand across the month or the absolute kWpeak across the month, neither of which seem as appropriate for this type of calculation.

In contrast to the above approach, the utilities uniformly stated their approach as ORU/ConEd summarized succinctly that "Under Alternative 2, O&R will take the capacity costs for the same . . . service class [as that selected for Alternative 1] and divide that lump sum by energy (kWh) usage for the [selected] class during the 460 peak summer hours." In other words, the utilities' proposed calculation is:

$$\frac{\Sigma\,(\mathrm{MCC\ ECSC_{Jan}} + \mathrm{MCC\ ECSC_{Feb}} + \mathrm{MCC\ ECSC_{Mar}} \ldots)}{kWh\ Usage\ ECSC\ in\ 460} \times Total\ kWh\ Solar\ Gen\ in\ 460$$

> ***MCC ECSC***

MCC $\boldsymbol{ECSC_{Month}}$ *= The given month's capacity charges in dollars for an example customer in the service class selected*
kWh Usage ECSC in 460 *= kWh expected to be used by that example customer in the service class selected in the 460 hours*
Total kWh Solar Gen in 460 *= kWh generated by solar in the 460 hours*

If you cancel the hours out of the top and bottom of the equation, it results in dividing the annual capacity costs by the Avg kW usage of the customer class in the 460 hours. This approach is thus, in effect, dividing all of the capacity costs for each month in a given year for the example customer in the service class selected by customer's average demand in the summer 460 hours. While we understand a customer class's capacity costs each month are related to its portion of the utility's expected share of the load during the NYISO peak hour, we do not feel that this approach is supported by the overall intent and language of the Order in that it results in an Alternative 2 that does not provide significant additional value as compared to Alternative 1 for encouraging projects to focus on peak summer hours. This has meanigful impacts on the incentive of projects to orient themselves or to incorporate storage to maximize production in these hours as discussed below .

b. *The Consequences of the Chosen Capacity Methodology are Significant, as the Utilities' Capacity Alternative 2 Does Not Provide Meaningful Additional Value to Solar in*

Several Utility Territories—Contrary to the Clear Intent of the Order

Staff and the Commission clearly intend Capacity Alternative 2 to provide additional value to encourage generators taking on more risk of performance at a time that is most valuable to the electrical system as a whole—a goal we support. As mentioned above, in the March 9 Order, the Commission explains that the purpose of Alternative 2 is "encourage project siting and design focused on peak summer hours", [25] and to "provide an incentive over the simple monthly average [of Alternative #1]".[26]

However, as currently proposed, this Alternative will not achieve these objectives in any meaningful way and will thus not fulfil the intent of the method as intended. Alternative 2 would only provide a minimal $0.001-.005/kWh more value for standard solar-only projects than Capacity Alternative 1 depending on the territory and because of the additional risk introduced by being more exposed to seasonal irradiance fluctuations and enhanced facility outage impacts, this value will be haircut in the financing of projects, further reducing even this minimal incentive and contradicting the intent behind this aspect of the March 9 Order (please see Table 1 below).[27] In addition, for solar-only projects, the utilities' approach to calculating Capacity Alternative 2 would mean a 20-40% reduction in the value of that component compared to our recommended interpretation of the order as described above. In many parts of the state, such a difference in the expected per kWh revenues for solar projects will make the difference between a functioning DER market and one that is no longer viable. Orienting these systems to be west-facing does not significantly change these results and thus the main intent of the Order, to

[25] "Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters", New York Public Service Commission, Case # 15-E-0751, pg 100

[26] "Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters", New York Public Service Commission, Case # 15-E-0751, pg 103

[27] Please note that we believe it is likely that the NYSEG and RGE also have an error in their Alternative 2 filing which resulted in their proposed value being 30% and 20% respectively less than we have been able to reproduce using the utility methodology. Such discrepancies were not encountered in our calculations for other service territories. Everything described here assumes that those two calculations have been corrected. If the NYSEG/RGE filings are not in error than their Alternative 2 values would be lower than Alternative 1.

incentivize such siting decisions, will not be met by the current interpretation of the Order's methodology.

Table 1 – Comparison of Capacity Alternative 1 vs 2 as Proposed by the Utilities for an Example __MWsc/2MWac Solar-Only Project

Example ___MWdc/2Mwac Solar Only with E3 Solar Generation Profiles			
Utility	**Alternative 2 Capacity Value in Value Stack From Utility Proposals - Last 3 Years Average ($/kWh)**	**Alternative 1 Capacity Value in Value Stack from Utility Proposals - Last 3 Years Average Weighted by Solar Generation Profile ($/kWh)**	**Difference Between Alternative 1 and 2 As Proposed**
ORU (SC3)	$0.01900	$0.0156	$0.0034
CHGE (SC2 Secondary Demand)	$0.01890	$0.0188	$0.0001
NatGrid W/One Example Solar Generation Profile (SC2 ND)	$0.01690	$0.0142	$0.0027
NYSEG Upstate w/One Example Solar Generation Profile (SC2 Demand)	$0.01600	$0.0111	$0.0049
NYSEG Hudson (SC2 Demand)	$0.02800	$0.0247	$0.0033
RGE (SC7 Demand)	$0.01500	$0.0121	$0.0029
ConEd NYC (SC9)	$0.02544	$0.0298	-$0.0044
ConEd Westchester (SC9)	$0.02101	$0.0201	$0.0009
The tan colored cells here indicate that there is only one year of data here for Alternative 2 and that is from the utility filing and not able to be recreated, as the utility has declined to share load profile data to recreate the 3 years value.			

For a number of reasons, the VDER tariff is seriously challenging the industry's ability to develop projects, particularly in the Upstate region. The current low wholesale energy rates upstate, the rapid decline in MW Block incentives, the use of a 3-year average to calculate the MTC (rather than a 12-month average), and the significant challenges with the DRV and LSRV methodology—not to mention the current upward panel price pressure stemming from the Suniva ITC trade case—have combined to create an extremely challenging environment in the territories of National Grid, NYSEG, and RG&E that is in no way offset by the lower land acquisition costs in these parts of the State. Capacity Alternative 2, if re-calculated as we have proposed to provide an incentive for system to take on more risk to benefit the system during times of high demand intended by the Order, could be a significant opportunity to bring some projects online in these large, underserved areas, and could help to more equitability allow accesses to solar and mitigate the challenging environment in these parts of the state and also take pressure off of parts of the state where development interest has been overwhelming and seen large interest concentrated in the smaller utility territories.

a. *The Proposed Methodology for Alternative 2 Does not Provide Sufficient Value to Drive Solar+Storage, and Alternative 3 is Not Viable at this Time Due to the Risks Involved and Lack of Existing Complex Algorithms and Full-Time Operational Facility Staff to Monitor and Control Dispatch*

The order mentions the value of deploying storage with solar today stating, “As the Staff Proposal and commenters acknowledge, energy storage is a key component of our energy future. The integration of storage into DER deployments and the utility system has the potential to substantially enhance DER’s capability to lower system costs and provide a variety of energy services.”[28] This near-term deployment of storage with solar goal is also in-line with the Governor’s Reforming the Energy Vision (REV) and Clean Energy Standard (CES) goals, and with the NY Legislature’s recent passage on June 22, 2017 of a set of bills calling for the setting of statewide targets for energy storage.[29]

CDG projects currently comprise the vast majority of the non-residential interconnection queue and are expected to be the largest sector by project type to utilize the new Phase 1 tariff. For CDG projects to be able to provide additional benefit to the grid and ratepayers, and help meet state goals, the opportunity to add storage is critical. Capacity is the only aspect of the value stack that is available to CDG projects to create the additional revenue needed to cover the capital cost of adding such storage to these projects.

Specifically, the two capacity methods with any additional value to offer CDG projects for storage are Alternative 2 and Alternative 3. The value of Capacity Alternative 2 for solar +

[28] “Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters”, New York Public Service Commission, Case # 15-E-0751, pg 48-49

[29] The bills passed were SB 5190 and AB 6571, direct that state’s Public Service Commission to develop an Energy Storage Deployment Program

storage projects is clearly greater than the value of Capacity Alternative 1, but it is still insufficient (even with west-facing systems) to encourage and support solar + storage development for CDG projects in most areas of the state. Alternative 3 offers more value than Alternative 2 for these projects, but unfortunately while it offers potential revenue more in line with what is needed to make such projects viable, it is currently unusable in a real-world financial sense due to the risk of non-performance (i.e. missing a year's NYISO peak and also having purchased kWhs throughout those months from the grid at a higher cost than the tariff credit in an effort to ensure performance during the one and only peak hour).

Specifically, while the NYISO peak hour has fallen within a certain wide time frame over the last decade (i.e. it has occurred in June, July, August, or September between 1-5pm EDT), this is a wide range and could change at any time and would be nearly impossible to predict in a given year depending on weather and changes in air conditioning and other technologies. To attempt to respond in real time to the NYISO load without complex control and dispatch algorithms that are not yet in place and/or full-time solar facility staff to monitor and control dispatch manually, which is currently uneconomic and not feasible given the scale of development and portfolios in New York today. Without such control algorithms or personnel, the risk of missing the NYISO peak hour would impose unsustainable risks on the system. For example, if the peak hour shifted to 6 pm on a September evening after the storage had been exhausted seeking to meet an earlier expected peak, than the system could face a near zero value under Alternative 3 for the next full year of capacity value. These considerations are meaningfully reduced under Alternative 2 as the hours of performance that determine the capacity value of the system are clearly prescribed and can be easily incorporated in the autonomous control algorithms of the storage system.

In addition, the interconnection rules for adding storage to projects have not yet been put in place in New York and as performance in Alternative 3 for CDG project with storage would likely require charging from the grid to avoid the possibility of reasonably foreseeable conditions in which, depending on weather, it would not be possible to confirm the viability of charging the batteries from the solar alone to match production to the NYISO peak hour. As a result, until it is clear how a solar+storage project will be studied as a load by the Utilities and what potential costs and upgrades will be typical as a result of that, it is impossible to determine the viability of using Alternative 3. Without more advance forecasting and control/dispatch tools and rules in place, Alternative 3 would bring unbearable risk from an financing point of view and thus would not be usable for CDG projects.

In conclusion, in order to be viable, the addition of storage to CDG projects must create a revenue stream that can be reasonably counted on and achieved today within acceptable bounds of risk. The revenue stream must at minimum covers its capital costs, and ideally would provide comparable return as compared to a project without storage. Neither Alternative 2 nor Alternative 3, as proposed to be implemented by the utilities, meet those requirements. We request that Alternative 2 instead be implemented in line with our recommendation so as to accomplish the intent of the Order: incentivizing systems that provide additional benefits during times of high demand.

2. The Base Service Class Selection for Capacity Alternative 1

a. *The Central Hudson, NYSEG, and RGE Methodologies for Selecting the Appropriate Service Class Look Correctly at the Correlation Across the 8760 Hours of the Year, but the National Grid, ORU, and ConEd Approaches Have Issues That Need to Be Corrected*

Under the March 9 Order, the utilities were directed to implement the Staff Proposal for capacity Alternatives 1 and 2. For Alternative 1, the utilities were directed to identify the "service class with a load profile most similar to a solar generation profile."[30] Although "similarity" can be interpreted in several ways, we believe the Commission's intent was for the utilities to select a service class whose expected demand would most closely match up with the expected generation of solar DERs, such that the capacity impacts imposed by that service class would most closely track the capacity contributions of solar DERs across all hours of the year.

[30] March 9 Order at 99

When identifying which of their service classifications has “a load profile most similar to a solar generation profile”, three of the six utilities (NYSEG, RG&E, and Central Hudson) employ a straightforward approach of using the statistical correlation between the hourly demand profile for each customer class and the generation profile for a typical solar facility.[31] This correlation was implemented in Microsoft Excel using the COREL function that calculates the Pearson correlation coefficient of a solar generator’s expected output in the 8760 hours of the year as compared to each service classifications expected consumption across the entire 8760 hours of a year. To select the service class to be used for Alternative 1, these utilities simply selected the load profile with the highest predicted correlation between hourly demand and hourly solar production. This approach makes sense from an analytical perspective, and we support it as the most reasonable interpretation of the March 9 Order.

The other three utilities, however, use different approaches that do not appear to comply with the intent of the March 9 Order. First, although National Grid proposes a correlation approach that is similar to NYSEG, RG&E, and Central Hudson, National Grid’s approach contains a significant error that renders its results highly questionable. Instead of evaluating the direct correlation between the solar generator’s performance over the year and the various service classifications’ usage over the year, National Grid attempts to fit a straight line to the solar generator’s performance across the hours of the year, and to compare the slope of this line to the linear fit for the service class load profiles across each hour. As a practical matter, taking such a linear fit does not make sense, because it implies that the solar generation is lowest at midnight on January 1st (hour zero) and highest at 11pm on December 31st (hour 8760). Such an assumption is erroneous for both solar PV and for the load profiles which should not be expected to follow a linear trend. For solar the generation profile should be lowest in the winter (i.e. both January 1st and December 31st) and highest in the spring/summer/fall months. As a result of fitting a line to data that is not, and should not be, linear and than using the slopes of those lines

[31] The utilities analyzed the majority of their service classifications, although each of them did not include some combination of classes—for example, their largest customers (who are presumably subject to Mandatory Hourly Pricing rates), time of use rates, outdoor lighting, and special rates. While we would like to see the rate classes considered standardized across the utilities, we generally understand the reason for these exclusions.

as a means of comparison, this approach is not accurately looking at the similarities between the solar generation and load profiles over the 8760 hours, and National Grid should correct their method to match the three above utilities mentioned. We should note that this correction will quite likely not serve to add anything to National Grid's base capacity value, and using the correct methodology may, in fact, decrease that value slightly. However, given the intent of the order the Clean Energy Parties feel that it is important that the most similar service class be selected correctly using the most relevant statistical method (i.e. the correlation coefficient).

Second, unlike all of the utilities above, Orange & Rockland (ORU) and Con Edison did not use or attempt to use any type of correlation across all 8760 hours of the year of the solar generation and their service classes. Instead they chose only to use the ratio of the solar generator's expected performance in just one hour of the day in one season(in this case 5pm in the summer months) to its annual generation, and compare that to the same ratio for each service class's expected usage[32]. We understand that the utilities pay for capacity based on the peak NYISO system hour, which can often occur around this time in this season (though it has fluctuated significantly in past years), but the ratio of generation or usage at a single time of day and season to annual kWh generation or usage clearly does appear to be consistent with the order's instructions to find a load profile most similar to the solar generation profile, as it is too narrow of a metric for such a sweeping conclusion to be made. Thus, we request that these two utilities adjust their approach to one that looks at the correlation between service class demand and solar generation across the full 8760 hours of the year—similar to the first three utilities mentioned above.

b. *The Customer Service Classes Selected Now to be the Capacity Value Basis for Phase 1 Implementation Should be Set and Remain the Same for Projects Over the 25 Year Term of the Tariff*

[32] Please note that even for this approach, which we see clearly as not a correct or complete analysis of the similarity between the solar generation profile and the various customer service classes load profiles, we are unable to recreate or fully see their analyses, as both ORU and ConEd did not share their service class load profiles when requested, and asserted that they would not share them publicly.

It is difficult to over-emphasize the importance that establishing a stable, predictable tariff has for supporting the Commission's vision for robust DER deployment. Few, if any, investors or customers will be willing to put significant capital at risk on DER projects if the very method for calculating revenues for those projects could be altered significantly within the first several years of a long-lived asset's lifetime. Consequently, we strongly recommend that the utilities be directed to continue using the service class selected for Alternative 1 for the duration of the 25-year Phase 1 tariff. In cases where a service class selected disappears or is consolidated into another service class, the successor service class (the service class absorbing the majority of customers from the disappearing class) should be used.

From a risk perspective, developers can model and financiers can get comfortable with the variability associated with the future expected capacity value within a known customer service class. However, we are skeptical that the developer and financial community will ever become comfortable with the risk associated with financing a project based on a component of the tariff that could theoretically be based on any service class now in existence or yet to be created.

As this aspect of the value stack revenue stream is essential for projects in most regions of the state to be viable, it is imperative that the capacity value be predictable enough to be considered usable by financial counterparties. Thus, we strongly recommend that the customer class used to determine the capacity value remain constant for the full term of the Phase 1 tariff.

c. *NYSEG Should Clarify in Its Implementation Filing and in Future Reporting Whether It Has a Different Capacity Value for its Selected Service Class Customers in Load Zones G/H/I As Compared to Rest of State*

From data shared in response to information requests from the Clean Energy Parties[33,34], it appears that NYSEG has a different capacity cost that it bills its selected service class in Load Zones G/H/I (referred to as the G-J Locality Market) as compared to Rest of State (referred to as

[33] New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation Response to VDER-17-001 (SEIA-1), June 19, 2017, pg 3 and Attachment 5
[34] NYSEG writes in the IR response, "Attachment 5 shows the NYSEG SC2 Monthly ICAP Adder per kwh for those NYSEG customers located in the G-J Locality since the formation of that price zone."

the NYCA). As customers are today apparently billed different costs for capacity in those two areas, solar generators in those areas should be credited at those different values under the Phase 1 Tariff. NYSEG's original implementation filing on May 1st, however, does not make this point clear.[35,36] Specifically it lists an illustrative snapshot capacity value for Alternative 1 and Alternative 2 in NYSEG and RGE, but does not list the capacity-zone-specific Rest of State and G/H/I value for NYSEG territories. The existence of a different capacity value for customers in those two areas makes sense given the structure of the NYISO capacity market and the New York transmission infrastructure. It also follows that DERs located in each respective capacity zone would contribute capacity value that is correlated with the capacity costs charged to customers in each individual zone. Consequently, NYSEG should be directed to clarify that DERs will be credited based on the capacity portion of the supply charge applicable to the selected rate class in the area in which the DER is located.

d. *Central Hudson Should Correct its Plan to Calculate Capacity Alternative One Once a Year in May Based on the Past 12 Months, and Instead Calculate It Each Month in a Real Time Basis to Provide the Most Accurate Compensation Possible and Be Consistent with the Other Utilities*

Central Hudson's proposed approach to arriving at a monthly base Capacity Method One value is different than the 4 other utilities. Specifically, Central Hudson writes, 'Central Hudson proposes to extract capacity charges on a per kWh basis, including concomitant working capital carrying charges and allowances for uncollectibles, from the monthly Market Price Charge ("MPC") applicable to SC 2 SD and *develop a per kWh rate effective each May 15 based on the most recent twelve month average*."[37] This is in contrast to the other utilities who have specified that they will calculate the capacity kWh rate on a real-time monthly basis based on monthly purchases or season purchases. For example, National Grid states, "As described in the VDER

[35] Value of Distribution Implementation Proposal of New York State Electric and Gas Company and Rochester Gas & Electric Company, Case 15-E-0751, May 1, 2017, pg 6 and 7
[36] Supplemental Filing from New York State Electric and Gas Company and Rochester Gas & Electric Company, Case 15-E-0751, May 15, 2017, pg 2
[37] Value of Distributed Energy Resources Implementation Proposal of Central Hudson Gas & Electric Corporation, Case 15-E-0751, May 1, 2017, pg 7

Order, Alternative 1 Capacity Value compensation will be based on the capacity portion of the effective monthly per kWh supply charge for the selected service class multiplied by the project's total net hourly kWh injections in the billing month. National Grid's supply charges for each service class are calculated monthly and made available in Supply Service Charge Statements filed with the Commission and posted on the Company's website." While we appreciate Central Hudson's desire to use a more stable mechanism of completely known costs, we support the approach of the 4 other utilities as real-time monthly capacity values are important so that the compensation is as accurate a reflection of solar's contribution to the grid in a given month as possible. Unless the annual average Central Hudson proposes was weighted for solar generation, the use of an annual average value would distort and likely reduce the revenue generated by solar projects in the summer. Thus, we recommend that Central Hudson update it approach to align with that of the other utilities.

e. *The MTCs for CDG Projects Should Be Updated Using the 3 Year Average Value for the Service Classes Proposed by the Utilities with the Corrections Detailed Above*

As further detailed above, the MTC for CDG projects should be updated now that the utilities have proposed the customer service classifications that are most similar to the solar generation profile. We recommend that the update should include the customer service classifications recommended by Central Hudson, NYSEG, and RGE, and the updated classifications for National Grid, ORU, and ConEd based on the above requested corrections.

f. *The Commission Should Formally Confirm That Solar + Storage Hybrid Projects Are Able to Select Capacity Alternative 1, 2, or 3*

At the June 12, 2017 Technical Conference, it was stated that by DPS Staff that hybrid solar + storage projects would be able to choose Capacity Alternative 1, 2, or 3 under the Phase 1 Tariff. This is also alluded to in the order in which the Staff recommendations are summarized as "the presence of energy storage should not result in any change in compensation except that compensation for environmental value and the MTC should only be provided for net monthly exports"[38]. While the order then went on to instruct Staff to present them another option that could be less restrictive and more in line with expected storage installation configurations especially for customers with significant usage, this statement definitely supports the idea that if a solar project wants to select Capacity Alternative 2, the presence of energy storage should not affect that. We strongly support this approach, as we will discuss below, Capacity Alternative 2 is essential to storage deployment with CDG projects in all areas of NY. To avoid any potential confusion in the future though, we do think it important that this be specifically confirmed in the upcoming implementation order.

v. Delivery Value

This section includes our cross-cutting comments and recommendations for all utility implementation proposals with respect to DRV and LSRV. Additional specific comments regarding the specifics of individual utility implementation plans on these issues are in the Appendix and the most recent MCOS study from Central Hudson is attached in the Appendix. The key points we wish to make on overarching delivery issues are:

- DRV and LSRV methodologies must use previously approved full MCOS values and DPS should deny proposals for untested and unreviewed methodologies that artificially limit the values used.
- Proposed methodologies for calculating DRV and LSRV should be fixed for the duration of the Phase 1 tariff.
- Reducing DRV or LSRV value to "share" savings is contrary to the Commission's order and biases system in favor of utility infrastructure investments.
- Any allowed changes to MCOS methodologies must be applied consistently to other utility requests for cost allocation and recovery.

[38] "Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters", New York Public Service Commission, Case # 15-E-0751, pg 46

- The 50% stretch methodology for determining DRV and LSRV compensation appears reasonable.

In addition, there are a number of specific issues with respect to the LSRV that must be considered:

- Methods must be used across all utilities for identifying LSRV zones and determining MW caps that are consistent with utility practices for new infrastructure upgrades and identified on a ten-year planning horizon.

- Compensation should be locked in at the execution of interconnection agreement, should not be retroactively adjusted, and should be available beyond the initial ten-year term.

- MW caps should be technology neutral and apportioned to eligible projects based on expected coincidence with the relevant peak.

1. Overarching Issues Regarding DRV and LSRV

a. *DRV and LSRV methodologies must use previously approved full MCOS values*

The utilities take varying approaches to interpreting their MCOS studies to determine DRV/LSRV. This results in wildly varying estimates of the delivery value provided by DERs. The chart below shows the discrepancy between each utility and, for each utility, the discrepancies between costs as stated in MCOS studies and values attributed to DERs for avoiding marginal costs.

Table 1. Comparison of Values from Utility Marginal Cost of Service ($/kW)

Utility	Utility Proposed Value	E3 Estimate[39]	Utility MCOS[40]
Con Edison	$226	$205	$226
Orange & Rockland	$70	$62	$70
Central Hudson	$15	$14	$133[41] (rate class average)
NYSEG	$31	$31	$48-$143[42,43]
RG&E	$31	$31	$64-$104[44]
National Grid	$66	$63 (large GS) $160 (residential)	$63 (large GS) $160 (residential)[45]

To address this discrepancy, and assure that DERs are properly valued, the Commission should direct the utilities to 1) use the most recent approved MCOS study available and 2) apply all costs from the MCOS study to establish DRV/LSRV.

The need for this correction is most clearly highlighted by the approaches taken by NYSEG, RGE, and Central Hudson. Both NYSEG and RG&E take a subset of the marginal costs identified in their most recent approved MCOS study and use those figures to calculate a value that is only based on growth-related network investments primarily involving expansion or reinforcement of upstream distribution, distribution substation and trunkline feeders in growth

[39] E3 Value of DR Technical Conference, June 2017, slide 5.

[40] From utility VDER filing materials except where noted.

[41] Central Hudson, "Marginal Distribution Cost Study", September 2015, COSP-1, Schedule A.

[42] NERA "NYSEG Marginal Cost of Electricity Delivery Service", May 2015, Tables 22 C & D "Derivation of Annual Distribution Facilities Costs – Before CIAC".

[43] Values are labeled "Total Annual Marginal Distribution Facilities Related Costs" and vary by rate class. The MCOS value for LGS TOU transmission customer of zero is excluded. The next lowest value is $48.01 for LGS TOU secondary customer. The highest value is for residential customers which combines $143.41/kW. The addition of the trunk feeder and upstream costs from Table 21 would add about $30 to these prices.

[44] Derived from NERA "Rochester Gas & Electric Corporation Marginal Cost of Electricity Delivery Service", October 2015. Table 21 of the NERA study titled "Derivation of Annual Distribution Substation and Trunkline Feeder, Upstream Line and Upstream Station Costs" gives a value of $32.58/kW for substation and trunkline feeder costs. Table 22 "Derivation of Annual Distribution Facilities Costs" has values ranging from $31.92 to $71.21 by rate class. Combining those two costs gives a range from $64 to $104 per kW.

[45] National Grid, Marginal Demand-Related Costs, Exhibit E-RDP-10, Schedule 2, Case 17-E-0238.

areas. This method ignores several other system needs, most notably in areas not undergoing growth, and those below trunkline feeders. This also arbitrarily excludes the ability of DERs to extend equipment life, increase reliability and resiliency, and improve power quality. Central Hudson also only considers a subset of potential marginal costs when estimating the DRV and goes even further by proposing a complex new probabilistic method for determining when upgrades will be needed. This methodology has never been approved for use by the NY DPS and raises numerous methodological questions, including:

- Are the historical load growth estimates applicable going forward? What about potential increases in demand due to the adoption of new end uses like electric vehicles and heat pumps?
- What is the proper application of risk tolerance to system planning? How many hours of exposure to outage or overloading conditions are acceptable?
- Is the P50 forecast method reasonable for delivery system needs or would more conservative approaches, such as P90, be appropriate?

Specific concerns with this methodology are further discussed in the Appendix. However, regardless of the specifics, this proceeding has not provided sufficient opportunities for stakeholders to examine this complex new methodology, propose corrections, or put forward alternatives. Each of these proposals from NYSEG, RG&E and Central Hudson also dramatically cut the delivery value available for DRV and LSRV. Most egregiously, for Central Hudson, the value drops from a system average of $133/kW to $14-15/kW, a reduction of nearly 90%. The VDER order clearly directed the usage of the most recently approved MCOS studies,[46] which as staff identifies, were filed as part of the Dynamic Load Management proceeding.[47] As a result, the only reasonable course for the Department is to deny the proposals from Central Hudson to use a new methodology or from NYSEG and RG&E to unreasonably limit the

[46] March 9 Order at 117 ("we direct utilities to file their most recent MCOS studies and workpapers in this proceeding within 10 business days to enable parties to become familiar with the data and information.")

[47] March 9 Order at 107 ("Staff proposes to base a DRV credit on the marginal cost of service (MCOS) studies developed by utilities to value peak demand reductions in the Dynamic Load Management proceeding."); *id.* at 107-108 *(*"Staff recommends that the MCOS study dollar per kW-year values used for Demand Response tariffs should be "deaveraged" to enable the calculation of two values for delivery cost savings from demand reduction: the DRV that applies across the service territory and an additional LSRV that would apply to high value areas for a limited number of MWs.").

categories of demand costs considered. The Department should direct all utilities to follow the straightforward approach used by ConEd and O&R, directly applying previously approved MCOS studies. For Central Hudson, this should mean its 2014 commission-approved MCOS study from Case 14-E-03189, attached as Appendix.

Relatedly, as the Clean Energy Parties examined the MCOS studies of the various utilities, it became quickly apparent that each utility's study is unique and that the studies lack uniformity. If the Commission's ultimate goal is a statewide DER market that responds to delivery system needs, it is imperative that in the long run the MCOS studies performed by utilities be standardized and made uniform. This includes both methodologies and terminology used by the utilities to conduct their studies. Without an effort to standardize the process and add more transparency, it will be near impossible to ensure that DER valuation is based on full avoided costs, and the state will fall short of its goal of developing a robust DER market that drives down distribution system costs. Regardless of the utility-specific differences that led to different MCOS study approaches in the past, the long-term vision for the DER market should not be balkanized within the borders of the state. Therefore, we strongly urge the development of a uniform methodology for Phase 2 that incorporates all of the delivery-related values of DER.

b. *Proposed Methodologies for Calculating DRV and LSRV Should be Fixed for the Duration of the Phase 1 Tariff.*

We cannot emphasize enough the reality that lenders and other financial parties that are essential to the functioning of the DER market will heavily discount or assign no value to components of the value stack that cannot be forecasted or predicted. Predictability and consistency in calculation methodology must be a touchstone of the VDER DRV and LSRV methodologies. Without it, these portions of the value stack will not be viewed as bankable sources of value and will not meaningfully contribute to the construction of new projects--an outcome we believe would be directly contrary to the purposes of REV and the VDER proceeding.

While the VDER Order provides certain parameters around the calculation of the DRV and LSRV, it leaves open many essential details. In finalizing these details in its Implementation

Order, the Commission must prioritize certainty, and minimize, to the extent possible, the degree of unpredictable regulatory risk introduced by the new framework. **At a minimum, this means that the Commission should fix (i.e. vintage) the methodologies for calculating DRV and LSRV for Phase 1 such that their future values can be reasonably predicted by market actors.[48]**

The VDER Order provides that DRV and LSRV rates/values shall be determined every 3 years. Any project that receives LSRV compensation shall receive the specific compensation rate for a period of 10 years. The DRV rate/value, however, is only fixed for the 3 year period prior to the time at which it is reset. The VDER Order does not address three critical questions related to DRV and LSRV value:

- How will new DRV rate/values be determined for subsequent 3-year periods?
- How will new LSRV be determined for subsequent 10-year periods?
- When a new LSRV zone is established, how will the commission determine which projects are selected as contributing to the MW cap?

It is critical that these questions be answered in the Implementation Order. Moreover, sufficient detail must be provided regarding these methodologies such that only external inputs (e.g. the number of DER on the system, economic changes, etc.) and not regulatory inputs, govern changes in the valuation.[49] This will allow market actors to develop revenue forecasts based on

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[48] The Clean Energy Parties are not here attempting to relitigate the Commission's decision to fix the *numerical rate* of compensation used for DRV and LSRV for less than the full term of the Phase 1 tariff, though we stand by our previous warnings about this policy choice and our recommendations for how to make DRV and LSRV more financeable. Our point here is simply that even if the DRV and LSRV *rates* will not be fixed going forward, the *methodologies* for developing those rates based on system inputs should not be wholly unpredictable and changeable during the span of the Phase 1 VDER tariff.

[49] We recognize that in practice, implementing this approach will require the utilities to keep their historical Marginal Cost of Service studies on file, so as to calculate system values based on changing inputs from their developing systems over time. Doing so is necessary to provide predictability and forecastability to *today's* investors. Were future values to be calculated based on future Marginal Cost of Service study methodologies, investors would have no way of predicting what those values will be because they have no way of knowing what regulatory changes will be implemented in developing new studies. Indeed, since regulatory change is contemplated, investors should *expect* that value to change, and will almost certainly discount heavily or completely any revenue streams based on such value. Implementing older methodologies alongside new ones is fairly common practice among utilities, as demonstrated through shadow billing techniques used in New York and across the country.

predictions of future DRV and LSRV value based on their assessment of these external inputs and confidence in the methodologies established in Phase 1. Without this level of certainty, market actors will not be able to predict future DRV or LSRV revenue streams, and those revenue streams accordingly will not contribute to incenting new projects.

In establishing DRV/LSRV valuation methodology, we strongly urge Staff and the Commission to collaborate with the New York Green Bank, whose expertise can inform the policy design by providing input as to the degree to which future revenues must be predictable in order to support financing. We expect that they too will counsel that methodological certainty is required in order to provide sufficient ability to forecast future revenues.

The value of certainty in forecasting future revenues was illustrated in the Commission's large-scale renewables proceeding, which ultimately provided an input to the Clean Energy Standard Order. NYSERDA and DPS conducted cost analyses of various financing options, through a large-scale renewables White Paper,[50] and in its subsequent Cost Study of the Clean Energy Standard. Both analyses concluded that fixed PPAs would facilitate lower total costs than an approach relying upon 20-year fixed REC contracts alone and leaving developers subject to swings in wholesale energy and capacity market revenues.[51] The difficulty of financing projects based on these wholesale market revenues (which themselves have far more predictable inputs than would DRV/LSRV should methodological certainty not be established) has proved to be a significant impediment to large scale renewables development in New York, and was a contributing factor in the state failing to achieve the 30% renewables goal set forth in its prior renewables portfolio standard.[52]

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[50] Case 15-E-0302, Large Scale Renewable Energy Development in New York: Options and Assessment (June 2015).
[51] *See, e.g., id.* at 101.
[52] While some markets have seen many natural gas generators financed on the basis of anticipated wholesale market revenues, it is worth noting that natural gas units enjoy a natural price hedge in wholesale markets that mutes the impact of uncertainty in market revenues on their ability to obtain financing. Natural gas units have relatively low up-front capital costs coupled with ongoing operations costs that depend on the price of natural gas. Importantly, however, the marginal unit in wholesale markets is very frequently a natural gas generator, meaning that prices are set in those markets based significantly on the price of gas. This co-dependency of a unit's costs and revenues mutes the impact of large price fluctuations on a natural gas generator's bottom line. Unfortunately, DER financed pursuant to the Phase 1 tariff will not enjoy any such natural hedge as values based on the value stack fluctuate over

The VDER process threatens to subject customers, developers, and financing partners to a far greater degree of uncertainty with regard to DRV and LSRV value than large-scale renewables developers currently face with regard to wholesale market revenues. If no methodology for determining value is set beyond a 3 year horizon (or 10 years in the case of projects that are eligible for an LSRV), project developers will have virtually *no* basis upon which to forecast future revenues, and these future value streams will inevitably be discounted nearly entirely in assessing the financeability of a project.

We are consequently concerned with statements in various utilities' implementation plans--discussed further below--that indicate that the utilities would change the very methods and rules by which they calculate the DRV and LSRV in the future to some new and yet-to-be-determined approaches. While methodological changes are appropriate for Phase 2, the prospect of a rules change mid-way through the Phase 1 tariff will mean that owners and developers cannot count on the methodologies established for Phase 1 when valuing their assets--a result that will have an immediate, chilling impact on the deployment of DERs in New York.

As we articulated in our proposals and comments during the development of the Value of DER tariff, we think that the best approach would have been to fix the specific $/kWh *rate* for DRV/LSRV. While the Commission chose a different approach in its VDER Order, fortunately, the VDER Order does provide room for at least a somewhat predictable revenue stream so long as the *methodology* is fixed for the future. In other words, so long as the Commission establishes clear rules for the development of future DRV/LSRV values in its Implementation Proposal, these values will still be able to contribute meaningfully to incenting the construction of new projects.

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time, since the relevant DER technologies have high up-front capital costs and low O&M costs. The lack of such a natural hedge (and the already substantial uncertainty that DER will face as a result of this for the energy portion of the value stack) underscores the importance of the values being predictable based on set methodologies.

Doing so would be relatively simple. Essentially, all it would entail is fixing the methodology by which each utility calculates DRV and LSRV, and providing that this methodology continue to be used when new DRV and LSRV values are calculated. When those values are re-calculated at 3-year intervals, the values themselves would change based on DER penetration, total load levels, infrastructure needs, and other exogenous factors.

Importantly, for future DRV and LSRV values to be forecastable, data must be provided as to the exogenous factors affecting future prices. For some data, such as economic growth forecasts, the onus would be on market actors themselves to gather it and make future predictions based on it. But other data, including data about the status of each utility's grid infrastructure, must be provided by the utilities. In evaluating and approving implementation methodologies for each utility, Staff should endeavor to identify the inputs on which future value will depend, and order the utilities to provide transparent data regarding those inputs.

The second potential critique is that fixing the methodology could provide for administrative complexity, by leaving Phase 1 projects on a prior methodology even if the method for calculating distribution value is updated in Phase 2 for other future projects. But *as compared to an approach where rates are developed through a variable methodology*, such an approach would in practice be relatively straightforward. Both volumetric and monetary grandfathered net metering projects will be credited differently than projects subject to the VDER tariff regardless of what approach is taken, meaning that the utilities will continue to require several options for credit calculation and billing. Second, regardless of the Commission's decision here, Phase 1 projects will likely need to be credited through an entirely different methodology than Phase 2 projects, because it is likely that the methodology for Phase 2 will continue evolving the way that DERs' contribution to avoiding distribution costs will be valued. An entirely different metric for determining analogues to DRV and LSRV could be arrived at in Phase 2. Thus, credit calculation and billing will need to be conducted separately for these Phase 1 projects than for other projects regardless of the methodology chosen. Indeed, *fixing* the methodology now provides for far greater administrative simplicity, because it averts the need for the Commission to pursue a regulatory process regarding Phase 1 DRV/LSRV methodology while simultaneously attempting to set a methodology for Phase 2 projects. Given the Commission's busy slate of proceedings, one less thing to do will ease simplicity for market actors, the utilities, and the Commission. Fixing the methodology will also facilitate a better Phase 2 process, because it would eliminate potential concerns from stakeholders that a methodology developed for Phase 2 could influence cost of service analyses in a manner that impacts Phase 1 projects.

While we recognize that the utilities' own data and methods are not currently as precise or granular as they could be, we urge the Commission to avoid changing the calculation methodologies for Phase 1 DERs mid-stream--even if this means that some DERs will be slightly over- or under-compensated some of the time. As the utilities improve their own data and methods for valuing DERs, those methods can be introduced in future iterations of the DER tariff--i.e., in Phase 2 and subsequent phases. At the same time, factors such as fluctuations in the load that drive the need for future utility infrastructure improvements will continue to inform future DRV/LSRV values, meaning that those values will respond to real time needs and changes on the distribution grid. Market actors can take responsibility for forecasting value based on those external inputs, but they must be given the tools to do so by--at minimum--knowing what the inputs will be in advance, and being able to access data that informs those inputs.

c. *Reducing DRV or LSRV Value to "Share" Savings is Contrary to the Commission's Order and Biases the System in Favor of Utility Infrastructure Investments*

As the Commission reiterated in the VDER Order, the goal of the Value of DER proceeding is to "accurately reflect and properly reward DER's actual value to the electric system."[53] In other words, the Phase 1 tariff is designed to provide accurate compensation to DERs for the long-run values they provide to bill payers and to society.

"Shared savings" approaches for certain elements of the value stack, discussed by Central Hudson, are contrary to the letter and spirit of the Phase I order, but also fail to minimize bill

[53] March 9 Order at 3.

payer costs in the long term. For each value specified in the order, the Commission lays out a methodology for translating that value into implementable credit structures, with no mention of the approach discussed by Central Hudson. Moreover, decreasing the compensation provided below the value that DERs are actually providing will lower the supply of DERs and increase the costs of financing these assets. Such an artificial undersupply, particularly for delivery values, will necessarily lead to higher load and more infrastructure upgrades--an outcome that is better for utilities given their current financial incentives, but worse for ratepayers. This proposal thus clearly undermines the creation of a level playing field between utility investments and third-party solutions.

Lastly, one of the central purposes of REV is to support the proliferation of DERs. This is for a number of public policy purposes, including the numerous values to bill payers and society that have not been included in the value stack under the Phase I Order. In view of this goal, the Commission should be implementing measures that support the economics of DERs, as long as they are fair for other bill payers and society. A shared savings approach as proposed by Central Hudson discriminates against DER in a manner that the Company would not treat its own investments in grid infrastructure and the goal of value-based compensation is fairness to all parties involved.

The Commission may and has considered other mechanisms that increase consumer surplus for ratepayers (for example requiring utilities to conduct Non-Wires Alternatives solicitations) by further encouraging DER deployment, but it would be unfair and contrary to the goals of REV to attempt to provide windfall “savings” to some utility customers (and utilities) by under-compensating DER providers for the values they provide. Therefore, the Commission should reject any approach to valuing DERs that involves an arbitrary adjustment for “sharing” the limited number of values that have been included in the value stack.

d. *Changes to MCOS Methodologies Should be Applied Consistently to Other Utility Requests for Cost Allocation and Recovery*

Proposals from several utilities indicate that the companies plan to change the way that distribution costs are projected and how the companies account for the ability of DERs to avoid those costs. The Commission should clarify that any changes or "enhancements" to the MCOS methodology introduced in the future would be applied in the same way to the utility's future requests for cost allocation and recovery in future rate cases. For example, if National Grid were to propose revised system performance criteria or load duration profiles for use in calculating DER compensation in the future, the utility should be required to use the same assumptions in requesting cost allocation and recovery for those types of investments. National Grid should not be permitted to use overly conservative assumptions in calculating the value that DERs provide while simultaneously being allowed to use different, more generous methods in calculating the compensation the utility itself seeks from ratepayers for the same kinds of distribution costs. Such an approach would undermine the development of robust and effective DER markets.

e. *The 50% "Stretch" Methodology for Determining DRV and LSRV Compensation is Reasonable*

The Clean Energy Parties support the proposal from several utilities to quantify LSRV by applying a 50% "stretch" to the system-wide DRV value. We understand that the utilities, policy-makers, and industry participants all have an interest in striking a balance between the goal of extreme granularity in valuation and the reality that the data available to reach this level of granularity are not currently available. In light of the fact that the VDER process will result in an iterative process that will become more fine-tuned over time, we think it is appropriate for now to use the 50% stretch approach to de-average the utility's MCOS study to estimate the numerous locational benefits that DERs provide.[54]

[54] NYSEG and RG&E propose to calculate more granular LSRV compensation. However, given the insufficiency of the underlying DRV calculation for these companies more work would be needed to determine an appropriate value for each proposed LSRV zone. Lastly, these companies delayed their response to relevant information requests until the morning of July 20th, making it difficult to provide an informed opinion by July 24th.

f. *The Utilities Should Be Directed to Notify VDER Tariff Customers in Advance of a Forecasted System Peak*

The utilities should be directed to include a notification protocol in advance of forecasted system peak so that DER providers are aware of when the system should be performing and can plan accordingly, and should not be penalized or have compensation reduced if the utility does not notify the developer. Tracking DER performance against such notices will yield valuable information about the production and reliability of DERs. This should be the case for capacity as well.

2. <u>LSRV Specific Issues</u>

a. *Methods Used Across All Utilities for Identifying LSRV Zones and Determining MW Caps Should be Consistent with Utility Practices for Infrastructure Upgrades and Based on a Meaningful Planning Horizon*

There should be symmetry between the assumptions and approach that each utility uses when deciding where and how to upgrade their distribution system and the assumptions and approach when calculating the value of avoiding those upgrades with DERs. Any inconsistency between how the utilities predict distribution-level investments and recover their costs, and how DERs are compensated for avoiding these investments, will ultimately result in unfair discrimination against DERs in favor of poles and wires. This means that utility approaches to load forecasting, equipment loading, outage exposure risks and any other rules for triggering system upgrades should strongly inform the determination of LSRV zone and MW caps.

In general, utility-specific rules for evaluation of infrastructure upgrades are opaque and, in many cases, utilities refused to provide detailed criteria in response to discovery questions. For more on this issue, the Clean Energy Parties refer the Commission to our specific critiques of the various utilities, with emphasis on Central Hudson in particular.

Next, the utilities have used divergent methods for determining the MW caps. National Grid proposes two criteria, limiting the MW availability to the lesser of (1) the reduction necessary to get to 100% of the planning rating or (2) the DER penetration equal to 25% of forecasted peak loading.[55] Both of these criteria are likely insufficient. First, reduction below the planned rating may be beneficial given future load growth and could further extend the life of the relevant assets.[56] Second, limiting DER penetration to 25% of forecasted peak loading is arbitrary and not justified. Third, concern about reverse power flow at minimum load levels would not apply to many technologies, such as solar plus storage, which could potentially *ameliorate* any concerns about reverse power flow. Fourth, National Grid should be striving to construct the distribution system in a manner that will allow for bidirectional power flow and animated markets in the future. In the shorter term, such concerns are adequately being addressed in the interconnection process. Other utilities, such as O&R, have not provided any quantitative criteria for their determination of MW caps.

Additionally, each utility should use a planning horizon of at least ten years, consistent with the compensation duration for LSRV. By limiting the planning horizon to three years, National Grid is very likely limiting the number of LSRV zones and the MW available in LSRV zones to DER, and are consequently undercompensating DERs that locate in areas that should have been identified as LSRV zones.[57] As long-term assets, DERs can provide load relief and other benefits far beyond the first three years of operation, and this value should be incorporated into utilities' LSRV valuation methodology.

b. *Compensation Should Be Locked in at the Execution of Interconnection Agreement, Should Not Be Retroactively Adjusted, and Should Be Available Beyond the Initial Ten-Year Term*

The Clean Energy Parties support National Grid's proposal to lock in the LSRV compensation of an eligible DER for ten years, beginning when the Interconnection Agreement is executed. The

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[55] National Grid Implementation Plan. Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources IMPLEMENTATION PROPOSAL FOR THE VALUE STACK COMPONENT OF VDER PHASE ONE TARIFF. Page 3

[56] The Clean Energy Parties recommend considering 80%, as Reducing loads to 20% below equipment planning ratings would permit a least a 10-year deferral before loads would reach 100% of the planning rating based on a generalized 2% annual growth rate.

[57] This critique is applicable to other utilities taking this approach as well.

execution of an Interconnection Agreement is a reliable signal of project maturity, and is an appropriate milestone for calculating LSRV and reserving an allocation with the MW cap in a given LSRV zone.

Relatedly, an LSRV reservation that has been locked in by execution of the Interconnection Agreement should not be retroactively impacted by future LSRV reservations, or by changes in the local area due to non-wires alternatives (NWA) procurements. To further promote stability and predictability, the LSRV should remain fixed at its original compensation level for the full ten years. Future projects receiving LSRV under the Phase 1 tariff should receive the value identified at the time that the interconnection agreements for those projects are executed.

Utility proposals differ on whether LSRV compensation would be available after the initial ten-year period. The Clean Energy Parties agree with National Grid's proposal to continue to make the LSRV available and recalculate the LSRV for a given project after the initial period has expired. The proposal is consistent with the directive of the order that the Phase I tariff must be available for the full 25 years. A DER located within an LSRV area will continue to provide benefit to the distribution system for the entire useful life of the system, and should be compensated accordingly. The magnitude of the benefit that the DER continue to provide may need to be recalculated periodically, but the benefit does not expire with the ten-year LSRV term. Conversely, limiting the LSRV term to ten years as proposed by ConEd and O&R undermines the core objective of the VDER tariff to appropriately compensate DERs for the contribution to the delivery system.

With regard to a methodology for calculating the value that an existing DER is providing beyond year 10 of the VDER tariff, it is important to appropriately compensate this DER for the value it provides to the grid by continuing to operate. One simple way to determine this value would be to conduct a "but for" analysis that would quantify the added cost that removing that DER from service would impose. The cost imposed by losing that DER is logically equivalent to the value that the DER provides by remaining in service for the following 10 years. It is critical that the Commission specify this methodology now, because the absence of this methodology makes it impossible to assign a value to LSRV compensation beyond 10 years and, thereby, reduces the overall financeability of DERs.[58]

c. *MW Caps Should be Technology Neutral and Apportioned to Eligible Projects Based on Expected Coincidence with the Relevant Peak*

Lastly, other key mechanics of the LSRV are not fully developed in either the VDER Order or the utilities' implementation plans. There must be a rational and orderly process for projects to reserve a portion of the MW cap and determine when the MW cap has been reached. Although such a system could be constructed in different ways, clear guidance from the Commission would be beneficial to create a functioning system that allows DERs to be used to avoid infrastructure upgrades. First, since the LSRV is open to all technologies, this system must be technology neutral. Second, since the overall goal is to meet a projected system need, these reservations must not be based on nameplate capacity, but rather the expected contribution to the system need. As an example, if there is a 10 MW cap in an LSRV zone that peaks around 6 pm, a 1 MW solar facility would only contribute in proportion to expected generation at 6 pm, unless paired with storage. If the hypothetical expected contribution at the relevant peak time is only 10%, then the LSRV reservation for such a project should only be 100 kW instead of the full nameplate capacity. In this hypothetical example, 100 MW of nameplate solar capacity would then be eligible for this LSRV zone, because 100 MW of nameplate is needed to avoid or defer an infrastructure upgrade. Such "reservation allocation factors" need to be developed for each eligible technology and LSRV zone. A transparent system must also be in place so that developers and other stakeholders can see whether space is available in a given LSRV zone. All of these measures are crucial to determining whether the LSRV concept will help avoid infrastructure upgrades.

III. CONCLUSION

The Clean Energy Parties appreciate the opportunity to provide input on Phase 1 implementation, and look forward to engaging with DPS Staff and other stakeholders in Phase 2.

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[58] If the Commission determines that a "but for" analysis is not appropriate, the Commission should at the very least require utilities to include avoided O&M costs after 10 years. This will signal to the market that some value, above zero, will be available after 10 years. However, this outcome would be a significant under valuation of the long term value of DERs, and this a "but-for" analysis should be used.

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/s/ Sean Garren
Sean Garren, Regional Director, Northeast
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APPENDIX A

a. BILL CREDITING FUNCTIONALITY AS RECOMMENDED IN APRIL 17, 2017 COMMENTS

i. Bill Credit Application

In its March 9 order, the Commission directed utilities to file Implementation Proposals by May 1 that include "utility processes for managing billing and tracking bill credits."[59] In addition, the Commission directed Staff to "confer with utilities and market participants to [sic] and report to the Commission regarding what actions can be taken to provide efficient two-way electronic communication between CDG providers and utilities regarding subscriber lists and bill credit calculation and application to customer bills to enhance customer experience and reduce customer management costs."[60]

We note that timely, accurate, transparent, and efficient bill credit application is fundamental to the successful implementation of a community solar program. Customers sign up to participate in community solar projects expecting timely and accurate credits on their electric bill, and it is the responsibility of community solar providers, utilities, and regulators, collectively, to ensure customers have the positive experience they expect and deserve.[61]

In October 2015, following the Commission's July 2015 order instituting the CDG program, each utility filed a CDG operating plan listing procedures for communicating with community solar providers regarding subscribers lists and bill credit allocation. Most of these procedures rely primarily on manual processes. Because the development of CDG projects stalled across the state awaiting the Value of DER order, only a few projects have come online and begun utilizing the processes laid out in the 2015 operating plans.

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[59] See VDER March 9 order, page 136.
[60] See VDER March 9 order, page 144.
[61] The emphasis in these comments is on efficient systems for CDG bill crediting; however, such systems can perform RNM bill crediting as well. RNM does not present quite as much of a bill crediting challenge as CDG because there are fewer satellite accounts, but solar project owners and customers have reported problems with RNM billing and some utilities have recognized that automation of RNM crediting would be helpful.

With the Phase 1 Value of DER order now in place, and the expectation that many more MW of CDG projects will come online over the next year, serving many thousands of customers, it becomes necessary and prudent to automate many of these processes to reduce error, lower administrative costs, and better serve customers, developers, and utilities. If customers are to understand and engage with the energy products they receive, which is a key goal of REV, there must be timely, transparent communication of all important data (including production and rate components), between utilities, developers, and customers.

We recommend that the Commission require utilities to implement systems with at least the following basic data and functionality:[62]

1. Project Registration

   a. Account creation and designation of project information (e.g. capacity, load zone, parcel designation, required documentation)

   b. Election of program choices (e.g. capacity value calculation alternative, election to retain E value vs. retain RECs, among others)

2. Subscriber Information and Validation

   a. Ability for CDG host to enter subscriber information, consent to disclose form, and obtain automated subscriber validation and historical production

   b. Ability for CDG host to make prospective updates to subscriber allocation percentages

3. Rate Information

   a. Applicable components of the value stack (E, MTC, capacity, load zone hub for LBMP, DRV, LSRV) based on project type, tranche allocation

   b. Energy values: upload/import rate information from utilities (e.g. retail NEM for Tranche 0, DA LBMP values from MHP tariffs for value stack tariff)

   c. Other tariff components:

      i. E Value: assigned by project upon payment of 25% of interconnection costs[63]

      ii. ICAP: upload from utility on annual basis

[62] This is not a fully comprehensive list. Utilities should work with experienced third-party software providers and community solar developers to develop full IT requirements.

iii. MTC: upload from utility at project commencement, for all customer classes
iv. DRV and LSRV: if applicable, upload from utility as they are established

4. Production Information by Project

a. Hourly production for all projects; ideally integrated through utility central hub for generator production data, allowing for tracking of official, utility-certified production on a live basis
b. Store historical hourly production information by project

5. Calculation of Credits

a. Using data on project, subscribers, and value stack elements identified above, calculate hourly credit assigned to each customer account
b. Generate bill credit file, by subscriber, with a copy of the report to the project owner
c. Can automatically flag any exceptions

6. Allocation of Credits Assigned to Host Account

a. Generation of credit file to post to host account, illustrating how credits were calculated
b. Track credit banking and rollover
c. Ensure compliance with program rules including two year grace period for expiration of credits, customer limits, etc.

7. Reporting

a. Automated generation of reports for all stakeholders (DPS, NYSERDA, utilities, project owners)
b. Controls for information security based upon participant role

8. Audit Functions
a. Allow for full auditing capabilities of all calculations, based upon federal and state requirements

The Commission and utilities should make adoption of online, efficient bill crediting systems a near-term priority. These systems can easily take six months or more to implement, which means work must begin now to accommodate the projects expected to come online in the next year. We have seen in other states, such as Massachusetts, the negative customer experience that can result from errors and poor communication associated with more manual processes.

Furthermore, given that New York is focused on reducing the soft costs of solar, it is important to recognize that inefficient crediting processes in other states have directly impacted the overhead costs for community solar providers, as customer service staff spend a significant amount of time trying to interpret opaque utility billing statements, attempting to answer customer questions about late or inaccurate credits, and trying to reverse engineer the utility rates and credit allocations to ensure all are done correctly.

New York can and should avoid those problems and help lower soft costs of CDG development by pursuing IT solutions now. Utilities should be required to consider third-party software and service solutions that can provide such functionality, as third-party solutions may be implemented more quickly and at lower cost.

APPENDIX B

a. <u>UTILITY-SPECIFIC CRITIQUES OF DRV/LSRV PROPOSALS</u>

i. National Grid

National Grid's April 24, 2017 *"Workplan and Timeline to Determine Location Value of Distributed Energy Resources"* introduces National Grid's proposal to move from its current methodology for developing MCOS studies to a new "enhanced" methodology that, according to National Grid, more explicitly considers areas of distributed energy resource (DER) opportunity and more "accurately" allocates operations and maintenance (O&M) costs.[64] The Clean Energy Parties recommend that - for the purposes of capturing the full range of benefits that DERs offer to the distribution system, and appropriately compensating DER assets for that benefit - the utilities should continue to use the original MCOS methodology set forth in their rate case filings for all projects under the Phase 1 tariff (Phase 2 tariff project compensation could be based on approved changes to the MCOS methodology). The MCOS study filed with each rate case is the most complete accounting of the marginal costs associated with adding infrastructure to the distribution system, and therefore represents an important measure (though not a complete measure) of the potential avoided costs that can be captured by DERs connecting to the distribution system. Any "enhanced" methodology that seeks to provide a more granular picture of marginal costs could have the unintended effect of underestimating the total available costs that are avoidable by DERs if it is implemented in manner that improperly excludes certain distribution costs that should be included. This is a possible outcome of relying on an "enhanced MCOS" that has not been sufficiently vetted through robust regulatory process and is overly reliant on utility assumptions and interpretation of avoidable costs. This could lead to lost opportunities to avoid costly upgrades with DERs or identify non-growth related benefits that DERs provide, ultimately resulting in inaccurate valuation of DERs and improper compensation that does not drive optimal levels of DER deployment.

[64] National Grid "Unbundling Plan." RE: Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources WORK PLAN AND TIMELINE TO DETERMINE LOCATIONAL VALUE OF DISTRIBUTED ENERGY RESOURCES. Page 7.

Under the March 9 Order, the DRV is to be designed to capture the diffuse, system-wide benefits that DERs located anywhere in the utility grid can provide, whereas the LSRV is intended to provide additional compensation for DERs that locate in specially designated high-value areas where the presence of DERs can provide additional benefits above and beyond the more diffuse system-wide avoided costs. However, by proposing to remove some of the items associated with its current MCOS methodology (e.g. O&M costs, capital projects associated with reliability and end-of-life equipment replacement) for purposes of calculating the DRV and LSRV in the future, National Grid's proposal fails to comply with the concept of the DRV, which is to capture all diffuse system-wide benefits that DERs provide. Therefore, the "enhanced" MCOS approach proposed by National Grid introduces the risk of undervaluing some of the more diffuse benefits of DER (e.g. equipment life extension, decreased O&M costs, decreased distribution-level line losses, increased reliability through decreased usage of equipment, etc). This proposal, if adopted, would erode the value of the Phase 1 tariff over time, and would risk undercompensating DERs for these distribution-level benefits.

More specifically, National Grid's current MCOS methodology, included with the utility's rate case filing, is informed by proposed capital projects with an array of primary drivers. For example, the MCOS work papers include projects to support load growth, reliability, end-of-life equipment replacement, and more. For the purposes of valuing the benefit of DER, that portfolio of projects should not be limited to capital projects driven by load growth alone (as suggested in moving from an MCOS model to an "Enhanced MCOS" model). Consequently, for Phase 2, National Grid should be required to calculate its proposed Annual Deferral Benefit by including all categories of capital projects and costs that were included in the utility's most recent MCOS study. National Grid should not be permitted to cherry-pick certain types of costs that could be avoided--e.g., those associated with load growth--while failing to compensate DERs for other categories of costs that they can help avoid.

ii. Consolidated Edison / Orange & Rockland (ConEd/ORU)

Orange & Rockland's Implementation Plan determined LSRV zone MW caps by

identifying the amount of load relief that would be required to bring LSRV areas into alignment with design standards or to operate constrained areas at improved capacity and thermal operating levels, based upon future forecasted loads in the upcoming ten-year planning period, and based on system analysis that determined areas operating with higher exposure and operating risk under contingency conditions.[65]

However, O&R has not provided the quantitative criteria used by the utility to connect load relief levels to specific MW amounts of DER. Therefore, it is impossible for stakeholders and the Commission to evaluate whether this criteria is valid or reasonable. Orange & Rockland should publish the quantitative and other criteria used to determine the MW caps, described in terms of peak loading reduction in a given area, or percent of equipment rating, similar to the methods described in the National Grid filing. Furthermore, consistent and predictable system planning practices should be used across service territories wherever possible, and as such, a common, objective criteria for developing MW caps among utilities with predominantly radial distribution networks should be adopted.

The Clean Energy Parties recommend (above) that the MW cap for National Grid be set at the amount of DER necessary to reduce peak loading to 80% of the equipment rating, and that no additional criteria related to minimum loading be used. We believe a similar approach for Orange & Rockland and the other utilities would also be appropriate, and urge the Commission to order the utilities to recalculate their LSRV zones for Phase I using this methodology.

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[65] ORANGE AND ROCKLAND UTILITIES, INC. IMPLEMENTATION PROPOSAL FOR VALUE OF DISTRIBUTED ENERGY RESOURCES FRAMEWORK, Case 15-E-0751, Page 4

iii. New York State Electric and Gas Corporation/Rochester Gas and Electric Corporation (NYSEG/RGE)

In addition to the issues identified below, several areas discussed in the utilities' DRV/LSRV Implementation Plan require additional clarification. First, there are no work papers available that support NYSEG and RGE's calculation of LSRV for specific system needs (pg. 5 of the Implementation Plan), and DRV available system-wide. Second, NYSEG and RGE have requested that work papers supporting its MCOS filing be withheld from public filing, which removes the ability of stakeholder to properly analyze and provide comment on methodology. Without explanation of how the utilities derived the MW caps or values, it is impossible for stakeholders to comment on whether the methodology is appropriate. NYSEG and RGE's implementation plan filing is therefore non-compliant with the VDER order until the utilities re-file it with a document that explains the methodology and provides backup data.

1. Step-by-step Calculation of DRV and LSRV Values

The Clean Energy Parties support aspects of NYSEG and RGE's workplan and implementation proposal. However, we note several areas in which changes and clarifications are required in order to fully evaluate whether this proposal complies with the March 9 Order and the goals of REV. Specifically:

- NYSEG and RGE should clarify what reserve margin would trigger a capital need, how far into the future load growth needs are being considered, and how those load growths are being forecast. As a general principle, these assumptions should not discriminate against DER investments relative to utility investments, and should incorporate potential cost deferrals at least 10 years into the future.

We agree with and support NYSEG and RGE's application of LSRV to areas that are concurrently considered for NWAs, but have not secured agreements with providers. This approach allows a utility to fulfill the system need with DERs that are compensated through

DRV and LSRV, obviating the need for a competitive NWA solicitation. In addition, NYSEG and RGE should clarify two issues:

- First, the utilities should clarify what threshold below NWA solicitation screening criteria is being used to identify these “severe” constrained areas.

- Second, the utilities should clarify that it will not reduce LSRV compensation retroactively if the utility awards an NWA contract in the DER’s LSRV zone.

2. <u>Differentiation by Voltage Levels</u>

NYSEG and RGE state that they will not consider the marginal cost of the facilities component of the network when calculating DRV or LSRV, consisting of secondary lines, primary-to-secondary transformers and local primary lines. This parameter leads to the assumption by NYSEG and RGE that DERs provide no value with respect to these assets, which is arbitrary and without merit. This parameter incorrectly discounts the value provided by DERs, and grants an unearned advantage to utility capital investments. As outlined in their Distributed System Implementation Plans, utilities are required to incorporate DERs into system planning and capital investments, including at the system levels that NYSEG and RGE have indicated they will not consider DER value. The utilities should consider and incorporate the value that DERs provide to this infrastructure in their ultimate DRV and LSRV filings.

3. <u>Determining the Basis to Compute System-Side DRV</u>

If the Commission decides to allow NYSEG/RGE to only consider load growth areas for DER compensation, NYSEG and RGE’s proposed first method for determining DRV is preferable to the second proposed method. The first method examines both near and long term needs across the system, rather than only looking at what NYSEG and RGE consider as “high value areas.” The second method arbitrarily assigns a zero-value to DER in areas where NYSEG and RGE have not identified capital needs.[66] If the first method is not feasible due to MCOS data limitations, then NYSEG and RGE can consider methods similar to the interim Phase 1 methods proposed by Con Ed, O&R and National Grid.

4. Determining Each Area's Net LSRV

NYSEG and RGE should consider a longer system needs forecast period than the proposed 3-5 year timeframe. Because considering that LSRV is meant to be fixed for a period of 10 years and T&D investments are typically planned on a 10 year horizon, failing to consider realistic time horizons misses opportunities to fully influence transmission investment, and also risks undervaluing the benefit that DERs can provide. The forecasting period should be long enough to capture the benefits of DERs that are long-lived (typically greater than 10 years).

5. Determination of MW Caps by Location

NYSEG and RGE's proposed method to set MW caps for LSRV compensation raises additional needs for clarification. For example, it is unclear how a solar PV project would be treated if, due to the assumptions, PV projects which were preliminarily discounted all performed beyond the MW cap according to system needs. NYSEG and RGE should clarify that if these projects over performed in aggregate, they would continue to receive full LSRV compensation even beyond the MW cap identified. A simpler alternative would be not to assign MW caps based on technologies, but simply forecast the system peak hours so that a developer could appropriately configure or size a system.

6. Determining the Eligibility of DERs Based on Expected Peak Period Performance

NYSEG and RGE incorrectly state that solar PV "may do little" to reduce network capacity expansion needs. This statement is counter to the spirit and requirements of this proceeding, as

[66] See NYSEG/RGE Phase 1 Implementation Plan at 5

ordered by the Commission, and is not factually supported. The entire purpose of performance requirements for DERs according to system peak is to compensate projects that perform during system peaks, and to limit compensation for projects that under-perform. NYSEG and RGE are prematurely and arbitrarily discounting the ability of intermittent resources to perform. Given the correct signals, DER providers will appropriate configure systems to maximize value and performance

iv. Central Hudson (CHGE)

Central Hudson's work plan methodology for determining DRV and LSRV is notably different from those of other utilities, and unfortunately does not comply with the requirements of the March 9 Order. Specifically, the Order requires the utilities to use the most recent filed Marginal Cost of Service Studies (MCOS),[67] which as staff identifies, were filed as part of the Commission's Dynamic Load Management proceeding.[68] In the DLM proceeding, Central Hudson filed the 2014 MCOS study from its previous rate case (Case 14-E-0318).[69] We have attached the correct MCOS study to these comments to this Appendix. Central Hudson further noted in its DLM filing that its supplemental probabilistic load growth study--which it is also proposing to use for DRV and LSRV calculation here--is merely an "approximation" of system-annual distribution costs--not a full study.[70] The language in the March 9 Order is reasonably clear that only a Commission-approved full MCOS study (as opposed to an unvetted probabilistic "approximation") is appropriate for use in Phase 1.

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[67] March 9 Order at 117 ("we direct utilities to file their most recent MCOS studies and workpapers in this proceeding within 10 business days to enable parties to become familiar with the data and information.")

[68] March 9 Order at 107 ("Staff proposes to base a DRV credit on the marginal cost of service (MCOS) studies developed by utilities to value peak demand reductions in the Dynamic Load Management proceeding."); *id.* at 107-108 ("Staff recommends that the MCOS study dollar per kW-year values used for Demand Response tariffs should be "deaveraged" to enable the calculation of two values for delivery cost savings from demand reduction: the DRV that applies across the service territory and an additional LSRV that would apply to high value areas for a limited number of MWs.").

[69] *See* Cases 14-E-0423, et al. – Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs, Central Hudson Marginal Distribution Cost Study (September 15, 2015) at 6 ("Central Hudson respectfully submits its most recent system annual marginal distribution cost of service study ("Study") that was originally filed in Case 14-E-03189. This Study was based on the five year capital program forecast for the calendar years 2015 through 2019.").

[70] Cases 14-E-0423, et al. – Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs, Central Hudson Marginal Distribution Cost Study (September 15, 2015) at 6.

It is telling that the $133/kW-year simple average marginal distribution cost using this Commission-approved MCOS study[71] would likely be **more than nine times the $14.55/kW-year DRV that Central Hudson proposes to use**. In other words, although Central Hudson is currently using rates and cost allocation methods for rate recovery based on an MCOS filing that shows marginal costs of distribution between $71 and $155 per kW-year, the utility proposes to compensate DERs that avoid these distribution costs at less than 11% of this value. The sheer difference in magnitude between the two figures strongly indicates that Central Hudson's proposed approach to DRV and LSRV ignores significant capital investments that should be included in the avoided costs for which DERs are compensated.

Another equally troubling aspect of Central Hudson's proposal is that the study Central Hudson proposes to use has not been subject to the usual evidentiary proceedings--including discovery, the ability to submit detailed interrogatories, and to question witnesses and methods--to which other MCOS studies and utility rate recovery proposals are subject. Unlike the other utilities' DRV and LSRV proposals, this fact raises the prospect that CHGE's study includes assumptions and methodologies that are non-standard and not acceptable for ratemaking, and therefore would be inappropriate for use in establishing the DRV and LSRV. The remainder of this section discusses the numerous shortcomings of Central Hudson's approach, but the most important concern is that the utility simply did not base its DRV and LSRV filing off of a Commission-approved MCOS study. For all these reasons, Central Hudson's filing should be deemed non-compliant with the March 9 Order.

1. Central Hudson's System Wide Avoided Transmission and Distribution Cost Study ("System Wide Study")

[71] The Clean Energy Parties are unable to calculate a load-weighted average because we do not have access to the loads associated with each service class.

As we note above, Central Hudson has not complied with the March 9 Order's requirement to use a Commission-approved MCOS study. The utility should be directed to use the 2014 MCOS study--the latest filed by Central Hudson--to develop DRV and LSRV.

Although the following comments do not apply to the 2014 MCOS study that Central Hudson is required to use in this proceeding, we believe it is also important to address the specific shortcomings with Central Hudson's proposed approach, as we understand that certain stakeholders may be interested in using this approach in Phase 2 and, perhaps, in later iterations of the Phase 1 tariff. In general, by attempting to apply utility planning practices in some aspects of its implementation plan, and additional requirements over those applied to utility capital in other aspects of the plan, Central Hudson has needlessly and arbitrarily restricted the ability of DERs to provide value to the system. We have attempted to note the many areas of arbitrary assumptions and inputs applied in Central Hudson's plan, and to offer improvement where possible.

A. ***Appropriate avoided cost value and customer benefit:*** Central Hudson, without any guidance from the Commission or Staff on the matter, assumes that compensation for value provided to the system should be derated to something below the actual avoided cost, so that it results in net savings for customers. Central Hudson also assigns an arbitrary rate to share avoided costs at 50%, drastically reducing the value that DERs should be compensated. As we discuss in the introduction to this section of our comments, the purpose of the VDER Phase I is to adequately compensate DER for the benefits they provide. Although we believe that moving to a DER future will provide net benefits to all ratepayers, it is inappropriate to use the VDER tariff to provide savings to ratepayers from DER investments that those ratepayers have not paid for. Central Hudson should recalculate its DRV and LSRV values without introducing this arbitrary and unsupported assumption.

B. ***Load Forecast & Avoided Cost Valuation:*** Central Hudson's method attempts to be the most granular in determining load forecasts, but does not take a full accounting of avoided costs that DERs provide to the system. Central Hudson uses monte carlo simulations to determine areas of load growth beyond substation and transmission area rating for 2 consecutive years, selecting a subset of the simulations for determining DERs' value. There are several issues with this method, which arbitrarily discounts DERs' contributions to the system. The parameters arbitrarily exclude system needs below the substation level, system needs that may occur beyond the next three years, and additional values that DERs are capable of providing to the system (e.g. equipment life extension, power quality improvement, reliability and resiliency increases, and others). By design, Central Hudson's methodology excludes many project types that are included in the rest of the JU's MCOS studies, erroneously decreasing the avoided cost calculations and, in turn, the available DRV/LSRV compensation available to DERs in their service territory.

Central Hudson's approach also suffers from procedural deficiencies. The assumptions and inputs into these load growth scenarios have not been approved by Staff or endorsed by stakeholders who may take issue with the data, processing, and other inputs into the modelling.

Overall, Central Hudson's methodology should be carefully reviewed for accuracy and propriety, specifically in the context of compensating DERs for their full range of benefits, and ultimately deferred for implementation in Phase II. Deferring full evaluation of this methodology to Phase II would bring Central Hudson into alignment with the rest of the utilities, who each proposed to develop more granular marginal cost methodologies to be included in future iterations of VDER.

C. ***Risk Tolerances:*** Central Hudson's description of its application of risk tolerances to system planning is unclear with respect to how this analysis relates to DER compensation values or mechanisms, and appears to conflict with its own reliability obligations and assumptions. In general, it appears that Central Hudson is proposing to derate distribution value to account for risk tolerance (though the methodology and assumptions are not stated clearly and therefore can only be guessed at by stakeholders and staff). However, it appears that the way CHG&E accounts for uncertainty in its capacity forecasting method is problematic. CHG&E's methodology implies that a large number of hours of exposure to outage/overloading conditions is acceptable: 88 hours for the transmission network, 263 hours for transmission loops, 263 hours for urban substations, and 350 hours for rural substations.[72] The premise underlying this methodology is generally inconsistent with industry standards. In fact, these conditions would constitute a violation of NERC standards for transmission facilities, and appear to be inconsistent with CHG&E's own transmission planning standards.[73] CHG&E's distribution system planning criteria would be helpful in assessing whether these risk tolerances are consistent with how it plans its own system, however we do not have access to the system planning criteria. The impact of CHG&E's proposed risk tolerance methodology for the VDER tariff is that it would require higher levels of load to signal a need for new or upgraded distribution capacity—possibly higher than what would be required under the utility's own reliability obligations to *create* a need for new or upgraded distribution capacity.

D. ***Risk Tolerance Application to Rate Recovery:*** In addition, it is not clear how these risk tolerances are applied to traditional utility capital investments and the usual requested revenue recovery--specifically, whether Central Hudson is applying different risk tolerance assumptions with respect to DERs than it applies to the distribution system investments on which the utility is permitted to receive a guaranteed rate of return. We propose that DERs receive equal treatment to traditional utility investments with respect to risk tolerances, and urge staff to require Central Hudson to clarify whether it is applying more negative assumptions to third party DER investments than it does for its own investments. Stakeholders asked Central Hudson's representative this question at Staff's Technical Conference and did not receive a response.

[72] [1] CHG&E Workplan in Case 15-E-0751, p. 4.
[73] Central Hudson Gas & Electric Corporation 2016. Transmission Planning Guidelines.

E. ***Annual Operations and Maintenance Costs:*** CHG&E's current filing mentions that it included operations and maintenance (O&M) expenses but did not provide the value or describe the methodology for calculating it.[74] According to material presented by E3 at the technical conference on June 12, 2017, CHG&E used an O&M cost of just $2 per kW-year (or $6 per kW-year if a "plant loader" item is included).[75] This value is an order of magnitude lower than CHG&E's own estimate provided in its 2014 MCOS study, which amounted to about $20 per kW-year.[76] Given that the 2014 MCOS study underwent regulatory scrutiny, we recommend that CHG&E use the O&M value estimated in the 2014 MCOS study.

F. ***Defined MW Need:*** Central Hudson has included a requirement that in order to be considered for value, DERs must defer a system need for 10 years or until they manage 10% of the peak need. This requirement is arbitrary and grants an unearned advantage to utility capital over third-party DERs. It also limits the number of identified system needs that DERs could serve. Central Hudson should eliminate this requirement from the ultimate implementing tariff.

G. ***Performance Requirements for DER:*** Central Hudson implies that PV is not an acceptable solution for system needs resulting from winter peaks. This implication is arbitrary, overly simplified, and does not address the use of PV in conjunction with other eligible DERs such as storage or load controlling devices. In general, DER values should be technology agnostic, and the compensation methodology (which is based on whether the DER performed during the top ten load hours, for example) will determine how much value each DER has the right to claim.

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[74] [1] CHG&E Workplan in Case 15-E-0751, p. 21.

[75] [2] Snuller Price. 2017. "Comparison of Distribution Marginal Cost Studies," E3, presented at the Value of DER Technical Conference on June 12.

[76] [3] CHG&E 2014 MCOS study, supplemental exhibit COSP-1, Schedule A.

2. Location System Relief Value Determination

Central Hudson's approach to LSRV determination appears systematically designed to discount the value of DERs. Each step as outlined by Central Hudson, although having some application in utility planning, either misrepresents the ability of DERs to meet system needs or needlessly limits the ability for a DER to capture that value.

There are several issues with Central Hudson's load forecast method as applied to DERs.

- First, the Nexant study, which is the baseline for calculations here, has not been adequately analyzed and vetted by stakeholders in this proceeding. Stakeholders, including Staff, may take issue with the methodologies and assumptions used in the study, and an adequate record has not been established to fully analyze it.

- Second, although the P50 forecast method proposed by CHGE may be prudent for system-wide supply needs in order to limit over-spending while maintaining reliability, it should not be applied to DERs in this context. Distribution systems have limited reserve capacity and forecasts of loads for local areas have a higher degree of uncertainty. Use of a weather extreme forecast helps address allocation of sufficient reserves under both normal and extreme weather conditions. CHG&E's distribution system planning criteria would be helpful in assessing CHG&E's forecasting methodology, however CHG&E has declined to make its distribution system planning document publically available. Many utilities use a P90 load forecast for this purpose, reflecting events that have a 10 percent chance of occurring in any given year (90/10 or once every ten years). CHG&E's load forecast only considers a 50/50 chance that load will be higher than forecasted. A P50 forecast, as proposed by CHG&E, is often used for generation planning, but distribution planning calls for a more conservative approach. Specifically, a P90 forecast leads to more robust distribution planning and supports safer and more reliable distribution system operation. Therefore, CHG&E should use this or a similar forecast when determining the value that DERs provide to the distribution grid.

- Third, CHG&E's methodology demonstrates bias concerning identification of system upgrades. In response to discovery on calculating the capacity limitation for the Hunter substation, CHG&E indicted that it determined a single 7.5 MVA transformer to have a long term emergency rating of 19.5 MVA. CHG&E's distribution planning document would be informative concerning equipment rating practices, however CHG&E has not made this document publicly available.[77] Nevertheless, rating a transformer for operation from 4 to 12 hours at 260% of name plate appears to be highly inconsistent with standard rating practices for power transformers and may lead to unsafe conditions.

- Fourth, under Central Hudson's proposed method, in order to be considered for avoided cost, a DER must defer a traditional investment for 10 years (or 10% of peak load is managed with DER) up to a maximum of 20% of the triggering facility rating limit. This approach seems arbitrary and inappropriately applied to DERs, in that it would not otherwise be applied to other utility capital investments. Specifically, Central Hudson provides no evidence that a DER deferring investments for less than 10 years or managing less than 10% of peak load cannot defer utility costs. In fact, in most cases, the converse may be true. Therefore, this arbitrary limit on DER's ability to receive compensation for deferral of utility costs should be rejected.

- Fifth, the proposal to limit DER compensation based on a percentage of the triggering facility's rating limit (in this case, 20%) also likely removes significant investment deferral opportunities. DERs--particularly a combination of DER types--could manage 100% of peak load in certain scenarios. As we discuss above with respect to National Grid and ConEd/O&R's proposal to artificially cap the number of MW eligible for LSRV based on reverse power flow concerns, any reliability-related concerns over reverse power flows or other issues that could arise with increasing penetration of DERs can be

[77] CH SEIA-3 IR-2

(and already are) handled through the interconnection process. The application of a 20% triggering facility limit is arbitrary and unnecessary, and should be rejected as such.[78]

3. Central Hudson's Proposal to Recalculate DRV and LSRV Every Two Years

It is unclear why Central Hudson proposed to updated DRV and LSRV values every two years. DRV values are intended to be fixed for three years, and LSRV values are supposed to be fixed for 10 years. Central Hudson should clarify and justify its proposal to use a different interval for updating these values.

[78] We further note that CHG&E's proposed limit is also substantially lower than National Grid's proposed limit of 25 percent relative to local peak loads--which we also oppose as arbitrary for the reasons described above.

APPENDIX C

Michael L. Mosher
Vice President
Regulatory Affairs

people. Power. Possibilities.
Central Hudson
A FORTIS COMPANY

September 15, 2015

Hon. Kathleen H. Burgess, Secretary
New York State Public Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

Re: Cases 14-E-0423, et al. – Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs

Dear Secretary Burgess:

In the Order Adopting Dynamic Load Management Filings with Modifications ("Order") issued and effective June 18, 2015 in the above referenced case, the Commission directed Central Hudson Gas & Electric Corporation ("Central Hudson" or "the Company") to file detailed marginal distribution cost studies within 90 days from the effective date of the Order.

Central Hudson hereby submits its response to this requirement.

In the event there are any questions related to this filing please do not hesitate to contact me or Glynis Bunt, Senior Director of Cost, Rates & Forecasts at 845-486-5420 or gbunt@cenhud.com.

Respectfully submitted,

M.L.Mosher

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs	Case 14-E-0423
Petition by Central Hudson Gas & Electric Corporation to Effectuate Dynamic Load Management Programs	Case 15-E-0186

Marginal Distribution Cost Study

September 15, 2015

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
284 South Avenue
Poughkeepsie, N.Y. 12601

Background

As part of the Reforming the Energy Vision ("REV") proceeding[1], the Commission initiated the instant proceeding on December 15, 2014, directing all electric utilities without dynamic load management ("DLM") programs to develop and file draft tariffs providing for the implementation of such programs for the summer of 2015[2]. In doing so, the Commission indicated that the dynamic management of distribution level load could result in the realization of many of the REV objectives including "deferral or avoidance of distribution or bulk power infrastructure spending, improvement of overall system efficiency, and furtherance of system reliability and resiliency."[3]

Central Hudson Gas & Electric Corporation ("Central Hudson" or "the Company") submitted its proposed DLM programs in a draft tariff filing on March 23, 2015. Subsequently, on June 18, 2015, the Commission issued an order ("June 18th Order") approving these DLM programs with modifications and directing further filings.[4]

DLM Programs

As of July 1, 2015, the Company offers two distribution-level demand response programs: the Direct Load Control Program ("DLCP") and the Commercial System Relief Program ("CSRP").

An event under the DLCP may be declared during the summer period of May 1st to September 30th when the New York Independent System Operator (NYISO) activates its Special Case Resources program in response to a forecast peak operating reserve shortfall, in response to a major state of

[1] Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015).
[2] Case 14-E-0423, Dynamic Load Management Programs, Order Instituting Proceeding Regarding Dynamic Load Management and Directing Tariff Filings (issued December 15, 2014).
[3] Ibid at p. 2.
[4] Case 14-E-0423, et al., supra, Order Adopting Dynamic Load Management Filings with Modifications ("June 18th Order") (issued June 18, 2015).

emergency, or at the Company's discretion to relieve system or area emergencies. Customers may participate in the Direct Install option if they agree to have a control device provided and installed free of charge by the Company on their load controllable equipment or they may participate in the Bring Your Own Thermostat ("BYOT") option wherein the customer agrees to purchase, install, and connect their own control device through a Company approved service provider. All customers participating in the DLCP may manually override the control device to regain control of their equipment during a called event. During the second year of participation, the Company will provide all customers that allow the Company to control their equipment for at least 80 percent of all event hours declared by the Company during the summer period with an annual performance payment of $50. Additionally, customers participating in the BYOT will receive a one-time sign-up bonus of $100.

An event under the CSRP may be declared during the summer period of May 1st to September 30th when the Company's forecasted load level is at least 94% of the forecasted summer system-wide peak. Customers will be given at least 21 hours advance notice for planned events and less than 21 hours advance notice for unplanned events. Customers participating in the CSRP directly through the Company must contract to provide at least 50 kW of load relief while aggregators must contract to provide at least 100 kW of load relief. Direct participants or aggregators may participate in the Reservation Payment Option or the Voluntary Participation Option. Customers in the Reservation Payment Option will receive $4 per kW per month in months with less than five events or $5 per kW per month in months with five or more events. All Reservation Payment Option customers will receive $0.25 for each kWh that is reduced during a planned event or $0.50 for each kWh that is reduced during an unplanned event. Customers that do not provide their committed load relief for events will incur a penalty. Customers in the Voluntary Participation Option will receive $0.50 for each kWh reduced during a planned event and $1.00 for each kWh reduced during an unplanned event.

June 18th Order Requirements

In addition to directing DLM program design modifications, annual reporting, and conformance of cost effectiveness calculations to the guidelines for Benefit-Cost Analysis which will be promulgated in the REV proceeding, the June 18th Order directed Central Hudson to file detailed marginal distribution cost studies for the purposes of designing DLM program payment structures for the summer of 2016 to be included as part of its respective petition to be filed on or before January 7, 2016 as also required by the June 18th Order.

Value of Distribution Capacity Relief

The locational value of DLM programs is tied mainly to supplying distribution capacity at the time of coincident demand, either by injecting power within the distribution grid from behind the meter generation or storage or by reducing demand. To the extent this is accomplished, system reliability is improved through the avoidance of equipment overloads and the unused capacity is available to accommodate load growth which may allow for the avoidance or deferral of investments that would have been required to meet such load growth.

In areas with growing local coincident demand, the value of distribution capacity relief can be quite substantial, particularly if DLM resources are sufficient to delay or defer distribution infrastructure upgrades and/or additions. In contrast, in some areas, local coincident demand is either declining, static or growing so slowly that existing distribution capacity is sufficient for the foreseeable future and further investment is not needed. In these areas, the value of distribution capacity relief is negligible to non-existent.

Other Company Initiatives

The Final Joint Proposal, approved by the Commission by order issued and effective June 17, 2015 in Cases 14-E-0318 and 14-G-0319[5], contained the signatories' agreement regarding procedures to be followed in the development of demonstration projects to be considered in Case 14-M-0101[6]. Pursuant to these procedures the Company filed a status report on May 1, 2015[7] describing the results of the effort up to that date in identifying the REV demonstration projects, sponsored by various entities, for the Central Hudson service territory. The letter accompanying that report further indicated that Central Hudson believed that the Company's Targeted Demand Response Demonstration Project ("Non-Wires Alternative ("NWA") Project") contained therein satisfied the Commission's requirement detailed in its February 26, 2015 order[8] for a non-wires alternative project.

The Commission, in the Rate Plan Order, agreed with the Company's assessment that the NWA Project satisfies the requirement of the Regulatory Framework Order, allowing the Company to potentially avoid the costs associated with transmission and distribution infrastructure investment and address expected load growth needs through an alternative demand response solution.

In developing the NWA Project the Company identified three areas where existing loads and forecasted demand growth could be timely addressed with DLM programs or incremental distributed energy resources, but absent these measures would be expected to require growth related investments in distribution capacity. The following table summarizes the peak load forecasts for these areas and the remaining portions of the Company's service territory.

[5] Cases 14-E-0318 and 14-G-0319, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Order Approving Rate Plan ("Rate Plan Order") (issued June 17, 2015).
[6] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV), Order Instituting Proceeding (issued April 25, 2014).
[7] Cases 14-E-0318 and 14-G-0319, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Central Hudson's Report Regarding the REV Collaborative and Developing Demonstration Projects (Status Report) (May 1, 2015).
[8] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (REV), Order Adopting Regulatory Policy Framework and Implementation Plan (Regulatory Framework Order) (issued February 26, 2014).

Forecast Year	Year	CH Peak Forecast (minus EE)	Area specific peak load forecasts			
			Area 1	Area 2	Area 3	All other Areas
1	2016	1152.4	57.8	14.2	126.5	953.9
2	2017	1151.3	58.5	14.4	127.3	951.2
3	2018	1150.3	59.1	14.5	128.0	948.6
4	2019	1148.7	59.8	14.7	128.8	945.4
5	2020	1145.1	60.5	14.9	129.6	940.2
6	2021	1148.0	61.2	15.0	130.3	941.3
7	2022	1150.8	61.9	15.2	131.1	942.5
8	2023	1153.6	62.7	15.4	131.9	943.7
9	2024	1156.5	63.4	15.6	132.7	944.8
10	2025	1159.4	64.1	15.8	133.5	946.0
11	2026	1162.2	64.9	15.9	134.3	947.1
12	2027	1165.1	65.6	16.1	135.1	948.3
13	2028	1168.0	66.4	16.3	135.9	949.4
14	2029	1170.9	67.1	16.5	136.7	950.5
15	2030	1173.8	67.9	16.7	137.6	951.6
16	2031	1176.7	68.7	16.9	138.4	952.7
17	2032	1179.6	69.5	17.1	139.2	953.8
18	2033	1182.5	70.3	17.3	140.0	954.9
19	2034	1185.4	71.1	17.5	140.9	955.9
20	2035	1188.4	72.0	17.7	141.7	957.0
Load Growth Rate		**0.16%**	**1.16%**	**1.16%**	**0.60%**	**0.02%**

As indicated in the table, the peak load forecasts for the three identified areas are expected to grow at rates of 0.6% to 1.16% and, absent the timely implementation of the targeted demand response programs of the NWA project, distribution infrastructure investments will be required in the next five years. While the Company identified one other area with peak load growth it was determined that this growth could not be timely addressed through DLM, thus requiring distribution capacity investment. Additionally, as indicated by the table above, the expected peak loads in the remainder of the Company's service territory are, on average, static to declining, indicating no need for additional distribution infrastructure investment. In both of these situations, the inability to timely address expected growth through DLM and static to declining peak loads, there is no value of distribution capacity relief.

Marginal Cost of Service Study

Based on the results of the aforementioned analyses performed for the development of the NWA project, and the fact that the targeted demand response programs of the NWA project will focus on those limited areas where load growth is anticipated, the Company does not believe that a marginal cost of service study performed at a more granular level will provide relevant information that can be utilized in the redesign of DLM program payment structures for 2016. In fact, the lack of growth coupled with sufficient existing capacity indicates that the value of distribution capacity relief is negligible to non-existent.

As a result, Central Hudson respectfully submits its most recent system annual marginal distribution cost of service study ("Study") that was originally filed in Case 14-E-0318[9]. This Study was based on the five year capital program forecast for the calendar years 2015 through 2019. However, as noted in the Company's testimony supporting the Study in Case 14-E-0318[10], the dearth of anticipated electric customer and load growth, as well as the concentration of capital expenditures on infrastructure replacements rather than growth, required an alternative approach that utilized inflation-adjusted actual distribution plant expenditures, which yielded an approximation of the system annual marginal distribution cost.

Respectfully submitted,

Glynis L Bunt

Glynis L. Bunt
Senior Director – Cost, Rates & Forecasts

[9] Cases 14-E-0318 and 14-G-0319, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Supplemental Exhibits of the Cost of Service Panel (September 15, 2014).
[10] Cases 14-E-0318 and 14-G-0319, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Supplemental Testimony of the Cost of Service Panel (September 15, 2014).

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Marginal Cost - Cost per Unit (kWh or kW)

			SC1 RNH	SC1 RHT	SC6 TOU	SC2 ND	SC2 SD	SC2 PD	SC3 PRI	SC13 SUBS	SC13 TRANS	SC5 AREA	SC8&9 Str & Trfk
			Residential			Commercial & Industrial						Lighting	
	Electric Distribution Plant Investment per kW												
[1]	Substation Plant		$ 500.54	$ 500.54	$ 500.54	$ 500.54	$ 500.54	$ 500.54	$ 500.54	$ 500.54	$ -	$ 500.54	$ 500.54
[2]	plus General & Common Plant Loader	12.86%	$ 564.90	$ 564.90	$ 564.90	$ 564.90	$ 564.90	$ 564.90	$ 564.90	$ 564.90	$ -	$ 564.90	$ 564.90
[3]	Economic Carrying Charge	10.98%	$ 62.03	$ 62.03	$ 62.03	$ 62.03	$ 62.03	$ 62.03	$ 62.03	$ 62.03	$ -	$ 62.03	$ 62.03
[4]	Plant A&G Loader	0.44%	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ 2.50	$ -	$ 2.50	$ 2.50
[5]	**Annual Carrying Cost on Substation Plant**		**$ 64.52**	**$ 64.52**	**$ 64.52**	**$ 64.52**	**$ 64.52**	**$ 64.52**	**$ 64.52**	**$ 64.52**	**$ -**	**$ 64.52**	**$ 64.52**
[6]	Demand Related Primary Plant		$ 229.47	$ 229.47	$ 229.47	$ 229.47	$ 229.47	$ 229.47	$ 229.47	$ -	$ -	$ 229.47	$ 229.47
[7]	plus General & Common Plant Loader	12.86%	$ 258.97	$ 258.97	$ 258.97	$ 258.97	$ 258.97	$ 258.97	$ 258.97	$ -	$ -	$ 258.97	$ 258.97
[8]	Economic Carrying Charge	10.98%	$ 28.44	$ 28.44	$ 28.44	$ 28.44	$ 28.44	$ 28.44	$ 28.44	$ -	$ -	$ 28.44	$ 28.44
[9]	Plant A&G Loader	0.44%	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ -	$ -	$ 1.15	$ 1.15
[10]	**Annual Carrying Cost on Dmd-Rltd Primary Plant**		**$ 29.58**	**$ 29.58**	**$ 29.58**	**$ 29.58**	**$ 29.58**	**$ 29.58**	**$ 29.58**	**$ -**	**$ -**	**$ 29.58**	**$ 29.58**
[11]	Demand Related Secondary Plant		$ 212.09	$ 212.09	$ 212.09	$ 212.09	$ 212.09	$ -	$ -	$ -	$ -	$ 212.09	$ 212.09
[12]	plus General & Common Plant Loader	12.86%	$ 239.37	$ 239.37	$ 239.37	$ 239.37	$ 239.37	$ -	$ -	$ -	$ -	$ 239.37	$ 239.37
[13]	Economic Carrying Charge	10.98%	$ 26.28	$ 26.28	$ 26.28	$ 26.28	$ 26.28	$ -	$ -	$ -	$ -	$ 26.28	$ 26.28
[14]	Plant A&G Loader	0.44%	$ 1.06	$ 1.06	$ 1.06	$ 1.06	$ 1.06	$ -	$ -	$ -	$ -	$ 1.06	$ 1.06
[15]	**Annual Carrying Cost on Dmd-Rltd Secondary Plant**		**$ 27.34**	**$ 27.34**	**$ 27.34**	**$ 27.34**	**$ 27.34**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 27.34**	**$ 27.34**
[16]	Demand Related Services		$ 78.52	$ 78.52	$ 78.52	$ 78.52	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[17]	plus General & Common Plant Loader	12.86%	$ 88.61	$ 88.61	$ 88.61	$ 88.61	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[18]	Economic Carrying Charge	12.52%	$ 11.09	$ 11.09	$ 11.09	$ 11.09	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[19]	Plant A&G Loader	0.44%	$ 0.39	$ 0.39	$ 0.39	$ 0.39	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[20]	**Annual Carrying Cost on Dmd-Rltd Services**		**$ 11.49**	**$ 11.49**	**$ 11.49**	**$ 11.49**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
[21]	**Annual Carrying Cost on Distribution Plant Investment per kW**		**$ 132.93**	**$ 132.93**	**$ 132.93**	**$ 132.93**	**$ 121.45**	**$ 94.11**	**$ 94.11**	**$ 64.52**	**$ -**	**$ 121.45**	**$ 121.45**
	line [5] + line [10] + line [15] + line [20]												
	Annual O&M Expense per kW												
[22]	Distribution Substations		$ 4.20	$ 4.20	$ 4.20	$ 4.20	$ 4.20	$ 4.20	$ 4.20	$ 4.20	$ -	$ 4.20	$ 4.20
[23]	Demand Related Primary Plant		$ 9.15	$ 9.15	$ 9.15	$ 9.15	$ 9.15	$ 9.15	$ 9.15	$ -	$ -	$ 9.15	$ 9.15
[24]	Demand Related Secondary Plant		$ 1.62	$ 1.62	$ 1.62	$ 1.62	$ 1.62	$ -	$ -	$ -	$ -	$ 1.62	$ 1.62
[25]	O&M Expense		$ 14.97	$ 14.97	$ 14.97	$ 14.97	$ 14.97	$ 13.35	$ 13.35	$ 4.20	$ -	$ 14.97	$ 14.97
[26]	**Total Annual O&M Expense per kW plus A&G Expense**	**44.75%**	**$ 21.67**	**$ 21.67**	**$ 21.67**	**$ 21.67**	**$ 21.67**	**$ 19.33**	**$ 19.33**	**$ 6.08**	**$ -**	**$ 21.67**	**$ 21.67**
	line [25] * 1.4475												
	Annual Working Capital Costs per kW												
[27]	Materials and Supplies	0.68%	$ 7.80	$ 7.80	$ 7.80	$ 7.80	$ 7.20	$ 5.58	$ 5.58	$ 3.82	$ -	$ 7.20	$ 7.20
	line [2] + line [7] + line [12] + line[17] * 0.68%												
[28]	Prepayments	12.39%	$ 2.69	$ 2.69	$ 2.69	$ 2.69	$ 2.69	$ 2.39	$ 2.39	$ 0.75	$ -	$ 2.69	$ 2.69
	line [26] * 12.39%												
[29]	Working Capital for Expenses		$ 3.10	$ 3.10	$ 3.10	$ 3.10	$ 3.10	$ 2.76	$ 2.76	$ 0.87	$ -	$ 3.10	$ 3.10
	line [26] * 1/7												
[30]	Total Working Capital Costs		$ 13.58	$ 13.58	$ 13.58	$ 13.58	$ 12.98	$ 10.73	$ 10.73	$ 5.45	$ -	$ 12.98	$ 12.98
[31]	**Annual Working Capital Rev Req**	**9.63%**	**$ 1.31**	**$ 1.31**	**$ 1.31**	**$ 1.31**	**$ 1.25**	**$ 1.03**	**$ 1.03**	**$ 0.52**	**$ -**	**$ 1.25**	**$ 1.25**
	line [31] * 9.63%												
[32]	**Annual Marginal Distribution Cost per kW**		**$ 155.91**	**$ 155.91**	**$ 155.91**	**$ 155.91**	**$ 144.37**	**$ 114.46**	**$ 114.46**	**$ 71.13**	**$ -**	**$ 144.37**	**$ 144.37**
	line [21] + line [26] + line [31]												
[33]	Approximate Marginal Cost per kW/Month		$ 12.99	$ 12.99	$ 12.99	$ 12.99	$ 12.03	$ 9.54	$ 9.54	$ 5.93	$ -	$ 12.03	$ 12.03
[34]	**Marginal Transmission Cost per kWh**		**$ 0.003370**	**$ 0.003370**	**$ 0.003370**	**$ 0.003370**	**$ 0.003370**	**$ 0.003260**	**$ 0.003260**	**$ 0.003189**	**$ 0.003154**	**$ 0.003370**	**$ 0.003370**

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Electric Marginal Cost - Cost per Customer

			SC1 RNH	SC1 RHT	SC6 TOU	SC2 ND	SC2 SD	SC2 PD	SC3 PRI	SC13 SUBS	SC13 TRANS	SC5 AREA	SC8&9 Str & Trfk
			Residential			Commercial & Industrial						Lighting	
	Electric Plant Investment												
[1]	Customer Related Distribution Plant		$ 7,443.53	$ 7,443.53	$ 7,443.53	$ 7,443.53	$ 7,443.53	$ 4,164.77	$ 4,164.77	$ -	$ -	$ 3,550.71	$ 42,333.93
[2]	plus General & Common Plant Loader	12.86%	$ 8,400.64	$ 8,400.64	$ 8,400.64	$ 8,400.64	$ 8,400.64	$ 4,700.28	$ 4,700.28	$ -	$ -	$ 4,007.27	$ 47,777.34
[3]	Economic Carrying Charge	10.98%	$ 922.39	$ 922.39	$ 922.39	$ 922.39	$ 922.39	$ 516.09	$ 516.09	$ -	$ -	$ 440.00	$ 5,245.95
[4]	Plant A&G Loader	0.44%	$ 37.15	$ 37.15	$ 37.15	$ 37.15	$ 37.15	$ 20.79	$ 20.79	$ -	$ -	$ 17.72	$ 211.31
[5]	**Annual Carrying Cost on Cust-Rltd Dist Plant**		**$ 959.54**	**$ 959.54**	**$ 959.54**	**$ 959.54**	**$ 959.54**	**$ 536.88**	**$ 536.88**	**$ -**	**$ -**	**$ 457.72**	**$ 5,457.26**
[6]	Services Unit Investment		$ 402.63	$ 402.63	$ 402.63	$ 603.94	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[7]	Meters Unit Investment		$ 362.19	$ 362.19	$ 1,221.95	$ 568.82	$ 2,540.31	$ 7,909.48	$ 17,028.57	$ 24,310.91	$ 24,310.91	$ -	$ -
[8]	Combined Service & Meter Investment		$ 764.82	$ 764.82	$ 1,624.58	$ 1,172.76	$ 2,540.31	$ 7,909.48	$ 17,028.57	$ 24,310.91	$ 24,310.91	$ -	$ -
[9]	plus General & Common Plant Loader	12.86%	$ 863.16	$ 863.16	$ 1,833.47	$ 1,323.56	$ 2,866.95	$ 8,926.51	$ 19,218.15	$ 27,436.88	$ 27,436.88	$ -	$ -
[10]	Economic Carrying Charge	12.52%	$ 108.07	$ 108.07	$ 229.55	$ 165.71	$ 358.94	$ 1,117.60	$ 2,406.11	$ 3,435.10	$ 3,435.10	$ -	$ -
[11]	Plant A&G Loader	0.44%	$ 3.82	$ 3.82	$ 8.11	$ 5.85	$ 12.68	$ 39.48	$ 85.00	$ 121.35	$ 121.35	$ -	$ -
[12]	**Annual Carrying Cost on Services & Meters**		**$ 111.89**	**$ 111.89**	**$ 237.66**	**$ 171.56**	**$ 371.62**	**$ 1,157.08**	**$ 2,491.11**	**$ 3,556.44**	**$ 3,556.44**	**$ -**	**$ -**
[13]	**Annual Carrying Costs on Investments**		**$ 1,071.43**	**$ 1,071.43**	**$ 1,197.20**	**$ 1,131.11**	**$ 1,331.17**	**$ 1,693.96**	**$ 3,027.99**	**$ 3,556.44**	**$ 3,556.44**	**$ 457.72**	**$ 5,457.26**
	line [5] + line [12]												
	Annual O&M Expenses												
[14]	Customer Related Distribution Plant		$ 81.62	$ 81.62	$ 81.62	$ 81.62	$ 81.62	$ 44.89	$ 44.89	$ -	$ -	$ -	$ 1,970.01
[15]	Meter Operations & Maintenance		$ 7.89	$ 7.89	$ 26.61	$ 12.39	$ 55.32	$ 172.25	$ 370.85	$ 529.45	$ 529.45	$ -	$ -
[16]	Meter Reading		$ 9.71	$ 9.71	$ 9.71	$ 9.71	$ 20.38	$ 52.68	$ 84.13	$ 84.13	$ 84.13	$ -	$ -
[17]	Bill Printing & Receipt Services		$ 4.07	$ 4.07	$ 4.07	$ 4.07	$ 8.13	$ 8.13	$ 8.13	$ 8.13	$ 8.13	$ 4.24	$ 8.13
[18]	Other Customer Service		$ 30.10	$ 31.07	$ 32.56	$ 33.63	$ 60.85	$ 521.00	$ 2,539.45	$ 13,455.78	$ 13,455.78	$ 33.04	$ 46.18
[19]	Customer Assistance		$ 25.59	$ 25.88	$ 26.67	$ 17.73	$ 22.65	$ 93.48	$ 525.30	$ 1,293.27	$ 7,352.01	$ 16.13	$ 587.19
[20]	Total O&M Expenses		$ 158.98	$ 160.23	$ 181.24	$ 159.15	$ 248.96	$ 892.44	$ 3,572.75	$ 15,370.75	$ 21,429.49	$ 53.41	$ 2,611.51
[21]	**Total Annual Gas O&M plus A&G Expenses**	**44.75%**	**$ 230.12**	**$ 231.93**	**$ 262.34**	**$ 230.36**	**$ 360.37**	**$ 1,291.78**	**$ 5,171.45**	**$ 22,248.73**	**$ 31,018.58**	**$ 77.31**	**$ 3,780.09**
	line [20] * 1.4475												
	Annual Working Capital Costs												
[22]	Materials and Supplies	0.68%	$ 62.71	$ 62.71	$ 69.28	$ 65.83	$ 76.28	$ 92.25	$ 161.92	$ 185.73	$ 185.73	$ 27.13	$ 323.43
	(line [2] + line [9]) * 0.68%												
[23]	Prepayments	12.39%	$ 28.52	$ 28.74	$ 32.51	$ 28.55	$ 44.66	$ 160.07	$ 640.83	$ 2,757.00	$ 3,843.73	$ 9.58	$ 468.42
	line [21] * 12.39%												
[24]	Working Capital for Expenses		$ 32.87	$ 33.13	$ 37.48	$ 32.91	$ 51.48	$ 184.54	$ 738.78	$ 3,178.39	$ 4,431.23	$ 11.04	$ 540.01
	line [21] * 1/7												
[25]	Total Working Capital Costs		$ 124.10	$ 124.58	$ 139.27	$ 127.28	$ 172.41	$ 436.86	$ 1,541.53	$ 6,121.12	$ 8,460.69	$ 47.75	$ 1,331.86
[26]	**Annual Working Capital Rev Req**	**9.63%**	**$ 11.95**	**$ 12.00**	**$ 13.41**	**$ 12.26**	**$ 16.61**	**$ 42.07**	**$ 148.47**	**$ 589.53**	**$ 814.86**	**$ 4.60**	**$ 128.27**
	line [25] * 9.63%												
[27]	**Annual Marginal Cost per Electric Customer**		**$ 1,313.50**	**$ 1,315.36**	**$ 1,472.96**	**$ 1,373.73**	**$ 1,708.14**	**$ 3,027.81**	**$ 8,347.91**	**$ 26,394.70**	**$ 35,389.88**	**$ 539.63**	**$ 9,365.62**
	line [13] + line [21] + line [26]												
[28]	Approximate Monthly Customer Cost		$ 109.46	$ 109.61	$ 122.75	$ 114.48	$ 142.34	$ 252.32	$ 695.66	$ 2,199.56	$ 2,949.16	$ 44.97	$ 780.47

Central Hudson Gas & Electric Corporation
Case No. 14-G-0319
Gas Marginal Cost - Cost per Mcf/Ccf

			Transmission	Distribution	Regulators & Meters	Combined
	Gas Plant Investment					
[1]	Average Plant Investment (2015-2019)		$ -	$ 9,024,718	$ 616	$ 9,025,334
[2]	plus General & Common Plant Loader	7.42%	$ -	$ 9,694,586	$ 662	$ 9,695,248
[3]	Economic Carrying Charge	10.30%	$ -			
[4]		10.10%		$ 979,153		
		12.28%			$ 81	
[5]	Plant A&G Loader line [2] * 0.36%	0.36%	$ -	$ 34,901	$ 2	
[6]	**Annual Carrying Cost on Plant Investment**		**$ -**	**$ 1,014,054**	**$ 83**	**$ 1,014,137**
[7]	Incremental Annual Sales (2015-2019)		327,504	327,504	327,504	327,504
[8]	**Annual Carrying Cost on Plant Investment per Mcf** line [2] / line [7]		**$ -**	**$ 3.096**	**$ 0.000**	**$ 3.097**
	Annual O&M Expense					
[9]	O&M Expense per Mcf			$0.330		$0.330
[10]	**Annual Gas O&M plus A&G Expenses**	**61.47%**	**$ -**	**$ 0.533**		**$ 0.533**
	Annual Working Capital Costs					
[11]	Materials and Supplies line [2] / line [7] * 0.68%	0.68%				$ 0.200
[12]	Prepayments line [10] * 12.39%	12.39%				$ 0.066
[13]	Working Capital for Expenses line [10] * 1/7	14.29%				$ 0.076
[14]	Total Working Capital Costs					$ 0.342
[15]	**Annual Working Capital Revenue Requirement** line [14] * 9.63%	**9.63%**				**$ 0.033**
[16]	**Annual Marginal Cost per Mcf**					**$ 3.663**
	Annual Marginal Cost per Ccf					**$ 0.3663**

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319
Gas Marginal Cost - Cost per Customer

			Residential	Non-Residential
	Gas Plant Investment (average 2015-2019)			
[1]	Customer Related Distribution Plant		$ 2,181,394	$ 2,181,394
[2]	Non-Residential Regulator Installations		$ -	$ 389
[3]	Services		$ 5,649,438	$ 5,649,438
[4]	Meters		$ 616,437	$ 439,016
[5]	Meter Installations		$ 1,125,941	$ 1,125,941
[6]	Total Incremental Annual Customers (2015-2019)		1,025	221
	Gas Plant Investment			
[7]	Customer Related Distribution Plant (2015-2019)		$ 1,750.72	$ 1,750.72
	line [1] / sum line [6]			
[8]	plus General & Common Plant Loader	7.42%	$ 1,880.67	$ 1,880.67
[9]	Economic Carrying Charge	10.10%	$ 189.95	$ 189.95
[10]	Plant A&G Loader	0.36%	$ 6.77	$ 6.77
[11]	**Annual Carrying Cost on Dist. Plant Investment**		**$ 196.72**	**$ 196.72**
	line [9] + line [10]			
[12]	Non-Residential Regulator Installations		$ -	$ 1.76
[13]	plus General & Common Plant Loader	7.42%	$ -	$ 1.89
[14]	Economic Carrying Charge	12.28%	$ -	$ 0.23
[15]	Plant A&G Loader	0.36%	$ -	$ 0.01
[16]	**Annual Carrying Cost on Regulators**		**$ -**	**$ 0.24**
	line [14] + line [15]			
[17]	Services		$ 4,534.06	$ 4,534.06
[18]	plus General & Common Plant Loader	7.42%	$ 4,870.60	$ 4,870.60
[19]	Economic Carrying Charge	10.10%	$ 491.93	$ 491.93
[20]	Plant A&G Loader	0.36%	$ 17.53	$ 17.53
[21]	**Annual Carrying Cost on Services**		**$ 509.46**	**$ 509.46**
	line [19] + line [20]			
[22]	Meters		$ 1,505.05	$ 2,890.14
[23]	plus General & Common Plant Loader	7.42%	$ 1,616.76	$ 3,104.66
[24]	Economic Carrying Charge	12.28%	$ 198.54	$ 381.25
[25]	Plant A&G Loader	0.36%	$ 5.82	$ 11.18
[26]	**Annual Carrying Cost on Meters**		**$ 204.36**	**$ 392.43**
	line [24] + line [25]			
[27]	**Total Annual Carrying Cost on Investment**		**$ 910.54**	**$ 1,098.85**
	line [11] + line [16] + line [21] + line [26]			
	Annual O&M Expenses			
[28]	Customer Related Distribution Plant		$ 24.23	$ 24.23
[29]	Meters & Regulators		$ 19.66	$ 85.34
[30]	Installations on Customer Premises		$ 6.01	$ 6.01
[31]	Service Laterals		$ 10.28	$ 10.28
[32]	Industrial Regulator Stations		$ -	$ 2.10
[33]	Meter Reading		$ 10.67	$ 21.33
[34]	Bill Printing & Receipt Services		$ 5.65	$ 11.29
[35]	Other Customer Service		$ 31.71	$ 44.28
[36]	Customer Assistance		$19.44	$ 17.18
[37]	Total O&M Expenses		$ 127.65	$ 222.05
	sum of lines [28] through [36]			
[38]	**Total Annual Gas O&M plus A&G Expenses**	**61.47%**	**$ 206.13**	**$ 358.55**
	line [37] * 1.6147%			
	Annual Working Capital Costs			
[39]	Materials and Supplies	0.68%	$ 56.65	$ 66.73
	line [8] + line [13] + line [18] + line[23] * 0.68%			
[40]	Prepayments	12.39%	$ 25.54	$ 44.43
	line [38] * 12.39%			
[41]	Working Capital for Expenses	14.29%	$ 29.45	$ 51.22
	line [38] * 14.29%			
[42]	Total Working Capital Costs		$ 111.64	$ 162.39
	line [39] + line [40] + line [41]			
[43]	**Annual Working Capital Rev Req**	**9.63%**	**$ 10.75**	**$ 15.64**
	line [42] * 9.63%			
[44]	**Annual Marginal Cost per Gas Customer**		**$ 1,127.42**	**$ 1,473.04**
	line [27] + line [38] + line [43]			
	Approximate Monthly Customer Cost		$ 93.95	$ 122.75

Central Hudson Gas & Electric Corporation
Cases 14-E-0318 & 14-G-0319

Comparison of Electric Rates

			SC1 RNH	SC1 RHT	SC6 TOU	SC2 ND	SC2 SD	SC2 PD	SC3 PRI	SC13 SUBS	SC13 TRANS
			Residential			Commercial & Industrial					
Marginal	Distribution Cost per kW/Month	Supplemental Exhibit __(COSP-1), Schedule A	$ 12.99	$ 12.99	$ 12.99	$ 12.99	$ 12.03	$ 9.54	$ 9.54	$ 5.93	$ -
	Transmission Cost per kWh	Supplemental Exhibit __(COSP-1), Schedule A	$ 0.00337	$ 0.00337	$ 0.00337	$ 0.00337	$ 0.00337	$ 0.00326	$ 0.00326	$ 0.00319	$ 0.00315
	Customer Cost per Month	Supplemental Exhibit __(COSP-1), Schedule B	$ 109.46	$ 109.61	$ 122.75	$ 114.48	$ 142.34	$ 252.32	$ 695.66	$ 2,199.56	$ 2,949.16
	Equivalent Cost per kW/Month		$ 13.42	$ 13.46	$ 13.73	$ 13.44	$ 13.13	$ 10.80	$ 10.99	$ 7.70	$ 1.91
Embedded	Demand Delivery Rate $/kW/Month	Exhibit __(COSP-1), Schedule C, Page 2 of 2	$ 5.21	$ 4.89	$ 5.99	$ 5.80	$ 8.78	$ 5.46	$ 7.24	$ 8.59	$ 5.90
	Energy Delivery Rate $/kWh	Exhibit __(COSP-1), Schedule C, Page 2 of 2	$ 0.00170	$ 0.00170	$ 0.00170	$ 0.00170	$ 0.00170	$ 0.00164	$ 0.00167	$ 0.00161	$ 0.00159
	Customer Charge per Month	Exhibit __(COSP-1), Schedule C, Page 2 of 2	$ 38.75	$ 38.54	$ 44.26	$ 42.83	$ 76.54	$ 276.33	$ 954.73	$ 3,739.96	$ 4,640.70
	Equivalent Cost per kW/Month		$ 5.42	$ 5.13	$ 6.36	$ 6.03	$ 9.34	$ 6.10	$ 7.98	$ 9.48	$ 6.86

Comparison of Gas Rates

			SC1 & 12	SC2, 6 & 13
Marginal	Demand Cost per Ccf	Supplemental Exhibit __(COSP-2), Schedule A	$ 0.36630	$ 0.36630
	Customer Cost per Month	Supplemental Exhibit __(COSP-2), Schedule B	$ 93.95	$ 122.75
Embedded	Delivery Rate $/Ccf	Exhibit __(COSP-2), Schedule C, Page 2 of 2	$ 0.31760	$ 0.02985
	Customer Charge per Month	Exhibit __(COSP-2), Schedule C, Page 2 of 2	$ 43.58	$ 64.73

BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service	Case 14-E-0318

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	Case 14-G-0319

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SUPPLEMENTAL TESTIMONY OF THE COST OF SERVICE PANEL

September 15, 2014

SUPPLEMENTAL TESTIMONY OF THE COST OF SERVICE PANEL

Q. Are you the same Glynis Bunt, Jay Tompkins Jr. and Linda VanEtten who submitted pre-filed direct testimony in the proceeding?

A. Yes.

Q. What is the purpose of your supplemental testimony?

A. The purpose of our supplemental testimony is to describe the electric and gas marginal cost of service ("MCOS") studies that we have completed as required by the Commission in its May 18, 2012 Order in Case 11-M-0542 and as addressed in our pre-filed direct testimony on page 22, line 13 through page 23, line 6.

The results of our studies are summarized on Supplemental Exhibit ___(COSP-1) and Supplemental Exhibit ___(COSP-2).

Q. What are the intended uses of these studies?

A. The results of these studies are intended to be utilized to update the discounted delivery rates for Excelsior Jobs Program ("EJP") participants which were originally implemented effective June 1, 2012 pursuant to Case 11-M-0542.

Q. Are you also filing updated EJP rates at this time?

A. No, not at this time. As there are currently no customers taking service under the EJP, the Company believes that any rate design changes required should be made at a later stage in this proceeding consistent with the determination of the final revenue requirement following the methodology proposed by the Panel below.

SUPPLEMENTAL TESTIMONY OF THE COST OF SERVICE PANEL

Q. What is the definition of marginal cost?

A. Since Central Hudson no longer owns significant electric generation or any gas production facilities, marginal cost for the Company is defined as the cost incurred to transmit and distribute an additional unit of electricity or gas.

Q. Please outline the method used to prepare the MCOS studies.

A. Generally, we identified marginal transmission, distribution and customer costs. Transmission and demand-related distribution costs so identified were compiled into a marginal volumetric unit rate while the customer-related distribution and customer costs identified were compiled into a marginal rate per customer.

Estimation of the marginal volumetric rate included identification of the projected capital costs resulting from increased throughput due to increased sales, including increased sales from existing customers as well as increased sales from the connection of new customers. We then developed an economic carrying charge rate to be applied to the identified capital costs to calculate the annual carrying cost on the plant investment. Next, we estimated the marginal annual operations and maintenance ("O&M") expense associated with the additional plant investment. In the final step, we recognized the marginal effect on working capital.

Estimation of the marginal customer cost included the calculation of the economic carrying charge cost, marginal annual O&M expense and marginal effect on working capital of the customer portion of the projected marginal capital costs identified during development of the marginal volumetric rate. The estimated marginal customer rate also includes other customer related expenses not directly attributable to plant investment.

Q. Please explain how the projected capital costs resulting from increased throughput due to increased sales were identified.

We analyzed the five year capital program forecast for calendar years 2015 through 2019 sponsored by Company Witness Haering to identify the projected capital investment associated with increased throughput due to increased sales. As Mr. Haering notes in his testimony, a significant portion of the electric capital program forecast is related to infrastructure replacements rather than growth. In contrast, slightly more than fifty-percent of the gas capital program forecast is attributable to growth, primarily as a result of the Gas Expansion program mentioned by Mr. Haering and more fully discussed in the testimony of Company Witness Campagiorni. As a result, we utilized the aforementioned gas capital forecast in the development of the gas marginal costs, but utilized a combination of the Company's Transmission Service Charge ("TSC") and historic distribution investment in the estimation of the electric marginal costs.

Q. Why did you utilize the TSC and historic data in the estimation of the electric marginal costs?

A. The dearth of anticipated electric customer and load growth as indicated on Exhibit __(FRP-2), and associated capital expenditures as previously noted, required a different approach. Under that approach, inflation-adjusted actual cumulative distribution plant expenditures were correlated to either normalized peak load or number of customers, depending on whether the plant was identified as demand or customer related, with the resulting coefficient in the equation utilized as the marginal estimate. With respect to the TSC, since Central Hudson is subject to the rules of the New York Independent System Operator, the Company's transmission revenue requirement is the basis for the Company's TSC. Entities, including Central Hudson, utilizing the Company's transmission system must pay the TSC, although no explicit payment is made by the Company. As a result, the TSC is the Company's marginal transmission cost. Since a forecast of the TSC is not available, the Company based the marginal transmission cost on a twelve month average of the TSC adjusted by energy loss factors resulting from the loss study submitted to the Commission on January 21, 2010 pursuant to the Order in Case 08-E-0887.

Q. Does the gas capital program forecast utilized include projected transmission investment?

SUPPLEMENTAL TESTIMONY OF THE COST OF SERVICE PANEL

A. Yes, however the planned transmission investment is not required to serve the anticipated load growth. As a result, the marginal cost of transmission is zero.

Q. Please explain how the economic carrying charge rate was developed.

A. A projection of the annual revenue requirements associated with the plant investment was made for the life of the investment, including depreciation, return (using the incremental cost of capital), income taxes, property taxes and property insurance. The present-worth of the stream of annual revenue requirements was then adjusted to produce a levelized cost in inflation-adjusted terms.

Q. Did you consider individual marginal O&M cost components?

A. Yes. We utilized an embedded methodology for O&M elements, which, according to the National Association of Regulatory Utility Commissioners, is a common and reasonable approach for these components, rather than a strict marginal method. We functionalized historic O&M costs by function for 1990 through 2013 using the results from the Rate Year ECOS studies submitted with our pre-filed direct testimony, and grouped into demand-related distribution and several customer-related categories.

Q. How was administrative and general (“A&G”) expense addressed?

A. A&G expense was addressed through the development and application of loaders, or adders, representing a historic average of inflation adjusted A&G expense to plant and/or O&M.

SUPPLEMENTAL TESTIMONY OF THE COST OF SERVICE PANEL

Q. Were marginal cost estimates developed for all O&M and A&G expense components?

A. No. O&M and A&G recovered through the separate Merchant Function Charge Administrative and Supply charges were excluded as these rates are not reviewed and/or adjusted as part of the EJP rate process.

Q. Please explain your inclusion of a working capital component in the MCOS.

A. The working capital component reflects the revenue requirement for the indirect costs including the requirement for additional materials and supplies as well as prepayment of and a working capital allowance for operation and maintenance and administrative and general expenses, all of which would be reflected in the Company's rate base.

Q. Have you compared the results of the MCOS studies to the delivery rates developed in the ECOS studies submitted in these proceedings and to the delivery rates proposed by the Forecast and Rates Panel?

Q. We have compared the results of the MCOS studies to the ECOS studies but not to the delivery rates proposed by the Forecast and Rates Panel. The Company followed this approach as these proposed rates reflect reallocation of the revenue requirement among service classifications based on the revenue allocation process applied by the Forecast and Rates Panel. The aforementioned comparison is presented on Exhibit __(COSP-3) and indicates that the marginal cost is only lower for electric

SUPPLEMENTAL TESTIMONY OF THE COST OF SERVICE PANEL

Service Classification No. 13, although electric Service Classification No. 3 shows a lower marginal customer rate.

Q. Why are the marginal rates generally higher than the embedded rates?

A. Generally, this is the function of higher per unit cost of new investment as compared to lower embedded cost of existing investment. For instance, the majority of the marginal gas investment is attributable to distribution mains, PSC account 376, and distribution services, PSC account 380. The average lives of the existing plant balances, which is reflected in the ECOS study, is approximately 70 years and 58 years, respectively. As a result, the average embedded cost tends to be significantly lower.

Q. Does this conclude your supplemental testimony at this time?

A. Yes.