STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Value of Distributed Energy Resources **Case 15-E-0751**

Comments Regarding the Future of Commercial and Industrial and Community Solar in New York and the Need for Improvements to the Value Stack

Clean Energy Parties: Solar Energy Industries Association, the Alliance for Clean Energy New York, Coalition for Community Solar Access, the Natural Resources Defense Council, the New York Solar Energy Industries Association, and Vote Solar.

Dated: June 15, 2021

Clean Energy Parties

The Future of NY Commercial and Industrial and Community Solar in New York and the Need for Improvements to the Value Stack

1) Introduction

The Clean Energy Parties[1] ("CEP") thank the New York State Energy Research and Development Authority ("NYSERDA") and the New York State Department of Public Service ("DPS") for its ongoing support of commercial and industrial ("C&I") solar projects, including community distributed generation projects ("CDG"), also known as community solar, in New York State. Together C&I and CDG projects in New York have installed 2.7 gigawatts of clean electricity capacity, created thousands of good jobs and extended the benefits that solar can provide to more New Yorkers than ever before.

With NY-Sun incentive monies for this market segment upstate now fully allocated, and other resources in New York also on the cusp of being fully allocated, the solar industry is at a crossroads. As NYSERDA stated in their April 21, 2021, technical conference presentation, commercial solar and CDG must continue to play a key role in order for New York to meet its climate and economic objectives. Massive amounts of additional clean electricity are needed to meet the overall goals of the Climate Leadership and Community Protection Act ("CLCPA").[2]

a) To continue to support C&I and CDG solar in New York regulators should improve and build upon the VDER tariff.

Together, NYSERDA and DPS have created a strong policy foundation to support C&I and CDG solar. The Value of Distributed Energy Resources ("VDER") tariff approved by the Public Service Commission ("PSC or Commission") established a fair compensation structure for large scale distributed solar projects. Furthermore, NYSERDA's NY-Sun declining block incentive program, also approved by the PSC, encouraged solar developers to invest heavily in New York by providing a transparent and predictable incentive structure.[3]

The declining block structure allowed developers to continue investing in projects even when the specific incentive level a project would receive was not known at the time they commenced the development process. The result of this ongoing public, private partnership has been a stable, growing market for C&I and community solar. The CEP appreciate that NYSERDA and DPS have convened two technical conferences to discuss the future of this market segment and that regulators are considering multiple options to sustain and grow this industry.

The CEP recommend modest adjustments to the VDER tariff to improve its accuracy, which will enable state regulators to reach the stated goals of the NY-Sun program for the C&I segment of

[1] The CEP is a coalition of the Solar Energy Industries Association, the Alliance for Clean Energy New York, the Coalition for Community Solar Access, the Natural Resources Defense Council, the New York Solar Energy Industries Association, and Vote Solar. Our perspective is informed by on-the-ground experience developing community solar & other distributed energy projects.

[2] Chapter 106 of the New York Laws of 2019.

[3] NYSERDA's focus on reducing soft costs for all distributed energy projects has also been effective driving down the overall cost of the NY-Sun program and encouraging development.

the solar industry – phasing out direct incentives and creating a self-sustaining market. As we will explain in these comments, the CEP strongly recommend that as NY-Sun's C&I/CDG funding comes to an end, the PSC responds by improving VDER's compensation as well as increasing New York's 6 gigawatt ("GW") distributed solar goal.

2) New York should increase its distributed solar goal to 12 gigawatts direct current ("dc") by the year 2030.

Obtaining 70 percent of New York State's electricity needs from renewable resources by 2030, per the CLCPA, has been a critical market signal for renewable energy development. The law, previous Commission orders, and other regulatory efforts from the Cuomo Administration have resulted in the development of hundreds of large and mid-size renewable energy projects in New York.

Even with this considerable progress and many projects under contract, NYSERDA's own analysis shows New York still needs approximately 31 million more MWhs per year – beyond the current 6 GW solar goal – to reach the CLCPA's 70 by 30 target now memorialized in the New York Clean Energy Standard ("CES").[4] Furthermore, regulators must keep in mind that the 70 by 30 milestone is only one important stop along the way towards the ultimate goal of zero emissions from the electricity sector by 2040 and an 85 percent reduction in greenhouse gas emissions ("GHG") economy-wide by 2050. Considerably more clean energy will be needed to reach that objective.[5]

New York state should put itself in the best position possible to accomplish a zero-emissions electricity grid by building and supporting <u>all</u> of the most promising renewables markets, which has become a thriving industry and has helped create more than 12,000 New York jobs.[6]

<u>To reach New York's long-term clean energy objectives, regulators should set a new goal of installing 12 GWdc of distributed solar by 2030</u>. Distributed solar, including CDG, is immediately deployable, creates jobs, and results in significant distribution grid benefits. Adding a new distributed solar – beyond the current 6 GW target – also serves as a hedge against the uncertainties in the timing of deploying large scale solar and wind. Distributed solar, including community solar, is deployable now and can ensure sustained progress toward state objectives while Large Scale Resources ("LSR") are coming online.

Our preliminary recommended distributed solar target of 12 GWdc is based on an extrapolation of the 10-year Wood Mackenzie/SEIA U.S. Solar Market Insight report forecast.[7] Furthermore,

[4] NYSERDA, "Future of New York. Commercial/Industrial & Community Distributed Generation Solar Markets," April 21, 2021. At slide 25.

[5] It is also worth noting that load projections are inherently uncertain and the Clean Energy Standard Order and supporting documents use the 2030 load projection of 151,678 GWh as the initial basis for formulating procurement targets. As with any projection, the 151,678 GWh projection at issue here is subject to substantial uncertainty and may need revisions based on the achievement of the state's energy efficiency goals, the pace of beneficial electrification, and the deployment of electric vehicles.

[6] NYSERDA, supra note 4. At slide 19.

[7] Wood Mackenzie/SEIA, "U.S. Solar Market Insight Report: 2020 Year in Review," March 16, 2021. At

https://www.seia.org/us-solar-market-insight

we analyzed the installations required to achieve 12 GWdc by utility as a percentage of utility peak load, capacity targets by utility territory, and the percentage of potential customers in these territories. Additional work is underway to refine modeling for an updated distributed solar goal.[8]

The CEP is not suggesting that a new distributed solar target be accompanied by additional incentives as was the case with the 6 GW target, which prompted NYSERDA's request for additional NY-Sun funding. However, such a target is still important to have as it will continue the state's focus on initiatives that improve grid integration and lower soft costs.

a) Policy makers should not look at current hosting capacity as a constraint to setting new distributed solar goals.

During the April 21 technical conference, NYSERDA staff and regulators asked whether new goals should or should not be limited by existing hosting capacity. In establishing a new solar goal, the CEP cautions regulators not to place artificial constraints on distributed energy's potential based on current levels of hosting capacity. Regulators should start their analysis from the goal of bringing enough distributed solar on the system to meet the CLCPA emissions reduction goals and then design, improve and construct a distribution system that can accommodate these levels of increased deployment. Indeed, the DPS already has the process of improving and upgrading renewable energy hosting capacity underway in Docket 20-E-0197 as part of implementing the Accelerated Renewable Energy Growth and Community Benefit Act.

Furthermore, regulators should identify opportunities to support and encourage utilities to adopt innovative technologies, such as smart inverters, that will also accommodate more renewable generation without the need for certain distribution system upgrades.

3) The upcoming DPS whitepaper on the future of New York commercial solar should propose increasing the VDER Environmental Value ("E-value") to be consistent with DEC guidance on the damages-based social cost of carbon.

The CEP recommend that the upcoming DPS whitepaper must include the option of updating the VDER E-value based on the New York State Department of Environmental Conservation's ("DEC") damages-based Social Cost of Carbon Guidance ("SCC or SCC Guidance") published in December 2020.[9] The clear intention of the CLCPA was for DEC to publish this guidance and for state agencies to apply it in decision-making. As we describe later in these comments, the marginal abatement cost approach presented by the state is not a marginal abatement cost ("MAC") analysis. A whitepaper that only includes the state's proposed MAC analysis will not be consistent with DEC's guidance or the intent of the CLCPA.

As we advocated at the second technical conference, increasing the E-value to be consistent with DEC's damages-based SCC Guidance is an expedient and justified approach that meets many of

[8] CCSA, Vote Solar, and other members of the Local Solar for All Coalition are currently working on additional New York specific modelling analysis.
[9] New York State Department of Environmental Conservation, "Establishing A Value of Carbon: Guidelines for Use by State Agencies," December 2020. At. https://www.dec.ny.gov/docs/administration_pdf/vocfguid.pdf

the state's policy goals. The DEC Guidance sets updated calculations and discount rates to establish the damages-based value of an avoided ton of carbon dioxide, and DPS already uses a damages-based SCC to determine the current E-value. The CEP's analysis shows that by only applying DEC's updated "central estimate" two percent discount rate into the DPS current calculation methodology, VDER's E-value increases by approximately $50/MWh, up from the current value of roughly $30/MWh (Appendix A).[10] This update would compensate for the end of NY-Sun incentives and provide a stable foundation for solar project development for years to come.

Furthermore, the environmental committee chairs in the New York State Legislature have encouraged this approach stating "[u]pdating the DPS calculations regarding the value of an avoided ton of carbon to be more consistent with the DEC's approach would help more accurately reflect the benefits that solar projects bring to the electric system."[11]

a) Modifications to E-value pursuant to existing Commission Orders can help make an updated E-value more accurate and limit costs.

In addition to updating the SCC discount rate, the DPS and the Commission should consider other modifications to E-value to make its value more precise. We recognize that the DPS must balance multiple interests including ratepayer impacts, equity considerations, economic development impacts, while at the same time strive to achieve the State's clean energy deployment mandates. We also recognize, as the PSC did in the 2018 Commission "Order Establishing Energy Storage Goal and Deployment Policy," that the value of avoided carbon is not in fact level over all hours of the year or locations of the state, as the current E-value compensation implies. [12]

Furthermore, analysis advanced by NYSERDA shows that the gap between projects' costs (panels, site development, construction and customer acquisition) and project revenue has narrowed considerably. The narrowing of this gap during the past five years can largely be attributed to NYSERDA's ongoing good work, industry efforts to lower costs, and the global reduction in solar equipment costs.

With these reasons in mind, we recommend NYSERDA and the DPS consider applying further modifications to how E-value is calculated based on a damages-based SCC. The resulting E value would be based on the DEC's full damages-based central value of avoided carbon but would be more tailored to the specific needs of the electric distribution system and could have the practical effect of lowering E-value compensation compared to a direct application of the DEC guidance.

[10] There are several additional recommendations to update the E-value calculations advanced by the CEP that were never addressed by the PSC and could also be revisited to update its value.
[11] Letter from Member of Assembly Steven Englebright and Senator Todd Kaminsky, Chairs of the Environmental Conservation Committees in the Assembly and Senate, respectively. April 20, 2021.
[12] New York Public Service Commission, "Order Establishing Energy Storage Goal and Deployment Policy" (Case 18-E-0130). December 14, 2018.

While the Commission should adhere to the DEC's recommendation to use a two percent discount rate, the Commission would be justified in considering other elements of the valuation of avoided carbon, such as the E-value varying by time of day/year, varying by zone, reflecting the expected reduction in carbon intensity of the electric grid over time, and/or the rising value of avoided carbon.

Such modifications would have the practical effect of tempering the cost of increased compensation for avoided carbon while ensuring carbon is accurately valued. Improving the defined E-value as part of VDER is the most efficient way of moving distributed solar forward in the state.

b) Further refining E-value is needed and results in incentives to DERs that complement the contribution of LSR resources.

The CEP strongly believe that both large scale and distributed generation solar projects are needed to reach New York's climate goals. A key finding of the recently released report "Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid" is that distributed energy resources, by shaping load, can help integrate higher penetrations of utility scale generation, leading to an overall lower cost portfolio.[13] New York is already well advanced in developing the VDER tariff which has this effect. In short, VDER compensated DERs complement the CES and keeping this compensation distinct, rather than extending REC solicitations to DERs, is the optimal policy.

New York has been moving DER to a dynamic tariff which will increasingly be a complement to utility scale generation. Beginning in 2014, New York began the process of revising compensation for distributed energy resources to make compensation based on the time and location of generation. The order establishing VDER in 2017 created a novel and nation-leading tariff structure whereby DERs are exposed to wholesale energy and capacity prices and to avoided distribution costs as identified in utility marginal cost of service. VDER has subsequently been modified on several occasions to make the tariff better reflect underlying grid needs and costs. The work continues: the Commission has recognized in the April 2019 "Order Regarding Value Stack Compensation" and the 2018 Energy Storage Order that further work is needed to refine the tariff, including the value of avoided carbon and potentially other non carbon pollutants.[14] An update to E-value now is a logical extension of that progress.

Therefore, the future of E-value should focus not only on the correct societal damages associated with carbon emissions, but also how that value affects the temporal and geographic variation in compensation for avoiding those societal costs. As the utility system evolves in response to generation from LSR this will become increasingly important.

[13] Vibrant Clean Energy, "Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid," December 2020. At https://www.vibrantcleanenergy.com/media/reports/#:~:text=Why%20Local%20Solar%20For%20All,over%208%20million%20new%20jobs.

[14] New York State Public Service Commission, "Order Regarding Value Stack Compensation," (Case 15-E-0751). April 18, 2019. See also supra note, 13.

Analyses by the solar industry and on behalf of the DPS all suggest that energy prices are likely to fall across the state during the next ten years, particularly during hours of solar energy production. An analysis for the CEP by Synapse Energy Economics found that average wholesale energy prices are expected to fall between 24 and 56% between 2021 and 2030 (Appendix B). In a 2018 presentation by the consulting firm E3 on behalf of the DPS, the firm noted that marginal emissions rates (which are strongly correlated with wholesale energy prices) are expected to fall to near zero in many of the mid-day hours of shoulder months (Appendix C). At the same time, the peak hours (and thereby the hours of generation and transmission capacity constraints) are expected to shift into the evening, from 2-to-7 PM to 5-to-10 PM.

In light of the evolution of the grid, shaping E-value will be important to further enhance the market signal that VDER gives through zonal energy pricing, capacity compensation, the demand reduction value ("DRV") and locational system relief value ("LSRV") elements of the value stack to focus exports of generation to the grid on the hours of greatest need.

4) As the DPS evaluates E-value changes, it should also consider additional VDER tariff improvements.

Among the values uniquely attributable to large distribution facilities is the avoidance of capital spending on new infrastructure – both deferring and avoiding upgrades of existing distribution infrastructure or construction of new transmission infrastructure purposely built to relieve congestion and deliver future renewable generation to load. VDER currently compensates large distribution assets for only one of these values and for only a portion of the useful life of the asset: it should compensate commercial assets for both values for their full 25-year asset life.

a) Extension of DRV

The DRV is a quantifiable value attributable to the characteristics of the CDG asset and is part of the VDER stack. This value is currently fixed for a period of ten years, with a reassessment of the value at year 11 for the remaining years of the asset's useful life (years 11-25). The current structure of this regulatory review of DRV creates finance risk for any entity developing a project, as financiers assume a zero value for DRV in years 11-25, which is contrary to the intent of DPS/NYSERDA. Instead, the asset's value in avoiding future utility expenditure should be received on an amortized basis over its useful life just as a utility asset's value/contribution to plant is returned to the utility on an amortized basis over its useful life. While it is possible that a

DRV could be reduced over time, it is also possible that this value would increase due to additional load on the system and other grid characteristics not heretofore contemplated by utility load forecasts (particularly those as disparate as the MCOS proceeding). In sum, to decrease unintended finance risk that will limit CDG deployment, DPS should consider extending a floor DRV for the full life of the asset.

b) Develop an avoided long-run transmission value

DPS should also account for the avoided transmission infrastructure and capacity costs associated with load reduction through CDG. Short-run transmission congestion costs are

included within the avoided energy costs through locational based marginal pricing. However, long-run avoided transmission costs have not been included within the current methodology.

The need for future transmission will only increase as New York brings more LSR online to meet the goals of CLCPA. For example, a study from the Brattle Group found that "between 3.5 GW and 6.6. GW of renewable capacity including 2-5 GW of solar and 2-3GW of wind will need to be added each year one average" to meet their aggressive target.[15] While the pipeline of projects in New York is encouraging, developing these projects is not without risk – small deviations in market conditions (attrition, project development timelines, financing) can significantly impact progress toward existing and future goals.

In many jurisdictions, avoided transmission value can be difficult to calculate due to uncertainty surrounding long term load projections and infrastructure needs. In New York, however, transmission infrastructure required by this aggressive deployment timeline is already being planned for and acted upon with some clarity, as addressed by the proposed construction in the PowerGrid Study commissioned by the PSC.[16] CDG resources will be a major part of any renewable deployment to achieve the 70 percent by 2030 goal, much less the 85 percent by 2050 goal. And DPS should study the contribution of the continued (and likely increased) deployment of CDG to avoid transmission expenditure in a manner like the DRV – it is a value created by the CDG asset, fairly calculated to create savings for customers over its useful life, particularly when paired with storage.

5) Regulators should avoid adopting an E-value based on the proposed marginal abatement cost approach.

Although the DEC SCC guidance also suggests that a "marginal abatement cost approach has been used in some instances, including in New York State in the electric power sector, to aid in planning to meet discrete greenhouse gas reduction goals" that analysis would take considerable time to develop.[17] The CEP agrees that well-executed marginal abatement cost analysis may be a useful exercise in determining an updated VDER E-value. A marginal abatement analysis would solve for the cost per ton of avoided CO_2 of the most expensive abatement measure needed to meet a given carbon reduction target. In these analyses, the initial costs of abating a small quantity of CO_2 are low, but costs rise as the quantity of abatement increases reaching the highest levels for reaching the last marginal unit.

However, what NYSERDA described at the first technical conference as a "marginal abatement analysis" however, was based on achieving a specific solar goal. This analysis appears to be an abatement costs analysis, not a marginal cost analysis. The difference is significant. A marginal

[15] Brattle Group, "Achieving 80% GHG Reduction in New England by 2050: Why the region needs to keep its foot on the clean energy accelerator," September 2019. At v.: https://brattlefiles.blob.core.windows.net/files/17233_achieving_80_percent_ghg_reduction_in_new_england_by_20150_september_2019.pdf

[16] New York State Public Service Commission "Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act," May 14, 2020. At: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FF8A7989-D35E-4636-8A9A F886808FD2F7}.

[17] NYSDEC supra note, 4.

abatement analysis would need to be conducted for a carbon reduction target across the entire electric system, not simply to reach a solar goal. While an actual marginal abatement analysis may be useful, the solar industry believes this approach is complex and would be time consuming. Regulators should instead focus on improving the E-value using updated damages based estimates, which have already been conducted and vetted.

6) The CEP oppose solicitations to set the future compensation for the CDG market.

The solar companies that are members of the organizations in CEP have serious reservations about New York using a competitive solicitation approach in the CDG market. Although this approach is used successfully in the CES, our member companies are concerned that there may be unintended consequences of applying that approach to this market, and that those risks will likely outweigh the possible benefits. For example, the competitive process will most definitely slow down the development process as companies wait for annual solicitations and a months long selection and contracting process. This extension of the development process will increase costs for developers and utilities.

a) Solicitations will create interconnection queue management challenges.

Developers will have higher soft costs to participate in solicitations. Bid preparation will require additional internal resources and likely external consulting fees. Developers will also experience a higher rate of legal and permitting write offs and wasted interconnection investments for projects that do not win awards. Likewise, utilities' transaction costs will increase to process those projects that lose, drop out of the queue, then reapply. That dynamic alone will make interconnection queue management more difficult and inefficient, but utilities will also have the added burden of winning projects frequently having interconnection queue positions behind losing projects. In those cases, the utilities will have to force losing projects out of the interconnection queue while winning projects are at risk until the utilities clear their path to interconnection. In stark contrast to an always on program that does not impose additional constraints on permitting and construction timelines, solicitations will inevitably lead to permitting and construction timelines converging to create spikes in demand for these services, likely leading to shortages.

New York is already realizing this challenge at a small scale. The Interconnection Policy Working Group has been debating how to address the study of projects which are behind several projects bidding into Non-Wires Alternatives ("NWA"). With all the projects in the interconnection queue it looks like later queued projects are non-viable, but this is only because most of the NWA projects will not be selected and will fall out of the queue. While this problem is isolated given the relatively small number of NWA projects, this problem could metastasize should distributed energy resource compensation become driven by solicitations.

b) Solicitations would be burdensome based on the sheer number of CDG projects.

While solicitations for LSR and offshore wind have been successful in recent years, there are good reasons to be skeptical of extending the approach to the CDG market. The volume, pace, and disbursed permitting authority of distributed energy development will present a host of

unique challenges that could lead to unfortunate side effects, like high attrition rates and higher costs and timeline disruption. The NYSERDA LSR Tier 1 solicitation has received tens of bids per year. Moving forward, each of those projects will apply and receive permits through a single Office of Renewable Energy Siting. Meanwhile, multiple times as many distributed projects have reserved NY-Sun incentives annually and each receives permits through the numerous authorities with jurisdiction. The walk-up nature of the NY-Sun program has been a better fit for the distributed market and helped to avoid overburdening an already challenging process with additional, unnecessary timeline constraints and peaky demand for local, state, and utility administrative resources. The state can preserve these benefits by avoiding solicitations and instead, administratively determine the appropriate value stack structure and value.

c) Solicitations are not a "cure all" for addressing changing market conditions.

Several participants at the April 21 technical conference made the point that periodic solicitations would help the solar industry respond to changes in costs. As the market changes, per the argument, bids will adjust from one solicitation to the next to stay competitive, while accounting for changes in costs. Under this argument, a given compensation level in an "always on program" or static program may persist, despite market changes that improve or worsen project economics. In practice, the industry anticipates that periodic solicitations will not actually be able to achieve a greater degree of responsiveness to the market.

While solicitations would inspire competition, which can generally be good for driving down prices, it historically rewards developers that are willing to bet on market improvements and ignore market risks. Also, the frequency at which solicitations can be repeated has practical limits. Any more frequently than annually will be resource prohibitive for NYSERDA and other critical agencies. Even with frequent solicitations, costs could decline between award and construction. (e.g., bifacials, ITC). Costs could also increase relative to expectations at bid (e.g., other trade disruptions, changes to labor requirements or availability). The consequences of solicitations adding additional degrees of complexity and uncertainty will not outweigh the low likelihood of improvement in program responsiveness to market changes.

Program responsiveness to the market and an always on program are not mutually exclusive. Thus, a tradeoff between program flexibility and the many risks enumerated above of shifting to a solicitation approach is a false dilemma. An always on program can and should be designed with mechanisms that maximize its responsiveness to the market.

If done correctly, an always on program can be as responsive to market changes as a solicitation, maybe more, while avoiding the risks and unintended consequences of solicitations. The CEP's recommendations above provide a menu of options for designing an always on Value Stack, with an administratively set E-value to be more dynamic with the market (e.g., periodic NYSERDA/DPS review and revision of marginal emissions rates so that E-value is consistent with progress towards CLCPA goals).

Perhaps the greatest risk of solicitations would be jeopardizing the state's ability to meet its CLCPA goals. Implementing solicitations will be a long and arduous process. Many projects that can help the state reach its CLCPA goals and some smaller developers may not survive that

process. Once solicitations are implemented, the risk of more projects being lost to undercutting bids, timeline delays, interconnection queue issues, and resource shortages persists. Today, the state can and should be celebrating its progress and likely success in achieving its 6 GW of distributed solar goal. However, if the state transitions to solicitations, there is a real risk that the state's distributed solar pipeline and stable of developers will not be healthy enough to achieve what is needed after 6 GW to get to zero emissions electricity by 2040.

7) The gap between large distributed solar project costs and project revenues has narrowed but regulators should seek to solve for compensation adjustments for the most representative projects within those ranges.

CEP member companies believe the range of "missing money" that results from the various cost/revenue scenarios presented by NYSERDA at the April 21, 2021, technical conference for a "typical" 5 MW project are not far off from developer experience. However, an estimate of the economics for a typical project fails to consider the distribution of projects in the cost/revenue ranges. That distribution is critical for the state to consider in any evaluation of what compensation is needed to reach its goals.

For example, from the developers' experience, the high revenue case, and the low cost CDG and remote net metering case combinations represent very few projects. In reality, most developer projects fall in the bottom half of the revenue range and the top half of the cost ranges. Therefore, NYSERDA should be solving for the 50th percentile within these ranges to allow more projects to reach construction and solve for the 2030 clean electricity goal.

Additionally, the state should factor into its analysis that developer risk is not captured in the per project economics estimates. For every great project that is built, a developer still absorbs the costs of projects that fail. And despite the narrowing gap, current cost declines may be slowing or be entirely undone by trends in domestic materials supply costs and new labor requirements.

8) Projects that missed the NY-Sun community adder or base rate megawatt block incentive should be eligible for new compensation structure to avoid job loss and uphold policy continuity.

Projects that have not received the community adder or megawatt block incentive should be retroactively eligible for the new compensation structure that results from the white paper. Retroactive eligibility of this structure is critical to (a) avoiding job losses, (b) maximizing the solar industry's local economic benefits, and (c) preventing project and interconnection queue attrition.

a) Avoid job losses

Based on analysis of the NYSERDA CDG pipeline, SEIA estimates that failure to address to expiration of NY-Sun incentives puts nearly 1.5 gigawatts of solar projects at risk resulting in approximately 7,000 New York jobs at risk as well. These jobs span across development, engineering, and construction firms. These firms cannot afford to stop working while the state conducts a long process to determine a new compensation structure if only projects developed

after the process concludes are eligible. Interconnection timelines, landowner option constraints, permit timelines, and other limitations require projects to move forward or be abandoned.

b) Maximize local benefits

Furthermore, distributed generation projects provide crucial property tax revenues to towns and lease payments to landowners. Assuming a $6,000/MWac property tax liability, not applying the new compensation structure retroactively would jeopardize $3 million in annual tax revenues. Given a two percent escalator over the first fifteen years, the property tax impact would total more than $50 million for this subset of at-risk projects alone.

c) Prevent project attrition

Retroactive eligibility of the new compensation structure would also prevent project and interconnection queue attrition. The successful NY-Sun program has signaled to the market that despite long two-to-three-year development timelines, developers should have confidence in investing in the state. The state failing to make its new compensation structure applicable to projects that missed out on Community Adder or base MW block incentives would send a signal to the industry that the policy continuity that has been a trademark of the NY-Sun program is no longer a guarantee.

Without confidence in policy continuity, the industry will slow down. This pause will impact the state's 70 percent by 2030 and longer-term decarbonization goals. Furthermore, project attrition will result in interconnection queue recycling, as developers look to time 25 percent interconnection deposits to align with the needed compensation structure. This recycling will create risk for all projects, even those that pencil, as utilities grapple with challenges around forecasting accurate interconnection upgrade costs.

9) The CEP recommendations would allow future NY-Sun funds to be directed to achieve other important public policy goals

If New York adopts the CEP recommendations in these comments, the resulting compensation model will allow the distributed solar industry in New York to sustain growth with the elimination of the NY-Sun program support for the C&I and CDG markets.

Future NY-Sun funding then can be used to pursue other important, hard to achieve policy goals, such as increased access to renewables for the low-to-moderate income sector; productive reuse of brownfields and landfills; or targeting projects geographically to avoid the use of fossil-fueled peaking power plants. These remain important policy goals and the state being able to put the full weight of NY-Sun incentives towards them in the future would send a strong signal to the market to accelerate development of these projects.

10) The DPS should use the whitepaper to clarify the rules around net crediting and remote crediting to further reduce soft costs

As the Commission deliberates over the future of distributed resources, it should use this opportunity to also clarify various other Orders (Net Crediting, Remote Crediting) to optimize existing programs so the most efficient projects are able to proceed through development without additional support. For example, current Net Crediting rules do not allow Remote Crediting

projects to participate. Nor can Net Crediting projects provide multiple savings discounts, which means projects participating in NYSERDA's forthcoming Inclusive Adder program will not be able to offer Inclusive participation a higher savings discount relative to market participants. If these Orders clarified, developers would be able to reduce soft costs for existing projects which would have a meaningful impact on the market now and create additional opportunities in the future.

11) Conclusion

Thank you for considering these recommendations. We look forward to continuing to work with NYSERDA and the DPS to sustain and grow a strong C&I and CDG solar market in New York. We would welcome the opportunity to discuss these recommendations with NYSERDA and DPS prior to the finalization of the upcoming whitepaper. Please contact David Gahl (dgahl@seia.org) with any questions about these recommendations in the meantime.

Respectfully submitted,

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Appendix A
From "Stabilizing the Community Solar Market by Revisiting VDER E-Value." May 7, 2021. Slide 25.

Updated E-Value Calc Below

RGGI Forecast**
($Nominal/US Ton)
RGGI, Inc** actuals
SCC Feb 2021* 2017 $5.51 $3.42
SCC - RGGI

2% DR DEC Values 2018 $5.86 $4.42 **per ton per MWH** $2020/metric ton $2020/US Ton $nominal/US ton 2019 $6.21 $5.43 x 0.553 2020 125 $113.40 $113.40 2020 $6.56 $6.41 $106.84 $59.08 2021 127 $115.21 $117.63 2021 $6.98 $110.66 $61.19 2022 129 $117.03 $121.87 2022 $7.39 1 $114.48 $63.31 2023 130 $117.93 $125.40 2023 $7.81 2 $117.59 $65.03 2024 132 $119.75 $130.00 2024 $8.45 3 $121.55 $67.22 2025 134 $121.56 $134.74 2025 $9.09 4 $125.65 $69.49 2026 135 $122.47 $138.60 2026 $9.73 5 $128.87 $71.26 2027 137 $124.28 $143.61 2027 $10.35 6 $133.26 $73.69 2028 139 $126.10 $148.76 2028 $10.96 7 $137.80 $76.20 2029 141 $127.91 $154.07 2029 $11.58 8 $142.49 $78.80 2030 142 $128.82 $158.42 2030 $12.32 9 $146.10 $80.79 2031 144 $130.63 $164.03 2031 $13.11 10 $150.92 $83.46 2032 146 $132.45 $169.80 2032 $13.94 11 $155.86 $86.19 2033 147 $133.36 $174.55 2033 $14.83 12 $159.72 $88.32 2034 149 $135.17 $180.64 2034 $15.78 13 $164.86 $91.17 2035 151 $136.98 $186.91 2035 $16.79 14 $170.12 $94.08 2036 153 $138.80 $193.36 2036 $17.86 15 $175.50 $97.05 2037 154 $139.71 $198.71 2037 $19.00 16 $179.71 $99.38 2038 156 $141.52 $205.52 2038 $20.21 17 $185.31 $102.48 2039 158 $143.34 $212.53 2039 $21.50 18 $191.02 $105.64 2040 160 $145.15 $219.74 2040 $22.88 19 $196.86 $108.86 2041 162 $146.96 $227.16 2041 $24.34 20 $202.82 $112.16 2042 164 $148.78 $234.79 2042 $25.89 **NPV** $862.82 2043 166 $150.59 $242.64 2043 $27.54
2044 168 $152.41 $250.72 2044 $29.30 **Constant 20 year payment that yields same NPV $80.32** 2045 170 $154.22 $259.04 2045 $31.17
2046 171 $155.13 $266.03 2046 $33.16
2047 173 $156.94 $274.80 2047 $35.28
2048 175 $158.76 $283.81 2048 $37.53
2049 176 $159.66 $291.43 2049 $39.93
2050 178 $161.48 $300.93 2050 $42.48

Appendix B
From Synapse Energy Economics. February 2021. Analysis prepared for the Clean Energy Parties.

Wholesale energy prices by NYISO Zone (2020$/MWh)

Year	A	B	C	D	E	F	G	H	I	J	K
2021	$ 25.45	$ 26.01	$ 26.67	$ 21.87	$ 27.57	$ 34.99	$ 36.45	$ 38.95	$ 38.44	$ 40.61	$ 57.12
2022	$ 25.68	$ 26.15	$ 26.83	$ 22.10	$ 27.76	$ 34.24	$ 35.69	$ 37.73	$ 37.08	$ 38.67	$ 49.68
2023	$ 25.40	$ 25.83	$ 26.41	$ 21.92	$ 27.26	$ 33.76	$ 34.96	$ 36.88	$ 36.23	$ 37.58	$ 47.60
2024	$ 24.86	$ 25.09	$ 25.60	$ 21.22	$ 26.36	$ 32.79	$ 33.72	$ 35.20	$ 34.58	$ 35.42	$ 44.85
2025	$ 25.11	$ 25.00	$ 25.49	$ 21.33	$ 26.16	$ 32.28	$ 33.08	$ 34.01	$ 33.32	$ 33.90	$ 41.35
2026	$ 24.98	$ 24.86	$ 25.31	$ 21.16	$ 25.89	$ 31.90	$ 32.40	$ 33.33	$ 32.71	$ 33.02	$ 41.99
2027	$ 22.62	$ 22.51	$ 23.08	$ 18.67	$ 23.44	$ 29.38	$ 29.51	$ 30.43	$ 29.81	$ 29.87	$ 37.88
2028	$ 20.23	$ 19.75	$ 19.81	$ 15.37	$ 20.05	$ 26.00	$ 25.89	$ 26.57	$ 26.05	$ 25.74	$ 30.47
2029	$ 20.20	$ 19.35	$ 18.98	$ 14.83	$ 18.96	$ 25.06	$ 24.03	$ 24.68	$ 24.02	$ 23.14	$ 28.03
2030	$ 19.31	$ 18.25	$ 17.79	$ 13.75	$ 17.66	$ 23.43	$ 22.30	$ 22.99	$ 22.27	$ 20.92	$ 25.31

Appendix C
From E3. Prepared for DPS.