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Submitted Electronically January 31, 2020

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey 08625-0250

3Degrees Comments on New Jersey Board of Public Utilities Notice for Comment on Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps

Dear Ms. Aida Camacho-Welch,

Thank you for this opportunity to provide comments to the Board of Public Utilities ("BPU") on the Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps. Specifically, these comments relate to Item #3 of the Notice, addressing how the cost caps should be determined and implemented.

3Degrees is a leading provider of comprehensive clean energy and carbon services that enable organizations and individuals to transition towards a low-carbon economy. 3Degrees is one of the largest buyers and sellers of renewable energy credits (RECs) in the country and serves hundreds of businesses, utilities, and other load serving entities. Over the past decade, 3Degrees has worked closely with solar projects and electricity suppliers in New Jersey in order to support the state in meeting its ambitious renewable energy, and solar-specific, goals.

3Degrees' comments focus on the topic of "exploring reforms to the Legacy SREC program that ensure a robust solar market while conforming to the statutory limitations on cost".

As the BPU is well aware, the state's SREC program has established New Jersey as a leader in the solar industry. The program has relied on basic market principles, designed in line with best practices for RPS design[1]. The existing SREC program

[1] *See March 1, 2019 comments of the Environmental Markets Association (EMA):* https://www.state.nj.us/bpu/pdf/publicnotice/stakeholder/20190305/EMA%20NJ%20BPU%20Solar%20Transition%20

provides a set schedule of solar generation targets with the SACP acting as a price ceiling. This has created a functioning, liquid market that benefits solar development by facilitating forward SREC contracts, contracting for SRECs multiple years into the future. As intended, this has fostered significant private investment in the New Jersey solar market.

3Degrees recognizes that the BPU is investigating all options available to balance the requirements of the Clean Energy Act of 2018, formalized in the New Jersey Transition Principles, including: (1) support the continued growth of the solar industry; (2) ensure that prior investments retain value; (3) meet the Governor's commitment of 50% Class I Renewable Energy Certificates ("RECs") by 2030 and 100% clean energy by 2050; and (4) comply fully with the statute, including the implications of the cost cap. We recognize that in order to ensure the cost cap is not exceeded while also ensuring the ongoing health of the solar industry, some certainty is needed regarding the total amount of spending that may be required for the Legacy Program in order to develop a transition and a successor program.

In order to protect existing investments in the market, any solution must retain the market-based structure of the Legacy SREC program. Staff should reject an approach that sets a fixed price for SRECs. Unfortunately, without additional clarity from the BPU as to how the numerator and denominator in the Cost Cap Equation are defined, we're unable to provide specific guidance on adequate or appropriate tweaks to any of New Jersey's solar programs that will ensure existing investments are not de-valued while also continuing to support growth in the solar industry.

Any fundamental reforms to the market that significantly reduce legacy SREC prices will necessarily undermine SREC Transition Principle #3 ("ensure that prior investments retain value") and risk seriously disrupting the market. As a general principle, 3Degrees believes that the SACP is the most appropriate means by which to set expectations on maximum prices in a market. However, any proposal that seeks to reduce the cost of SRECs by reducing the *pre-existing* SACP schedule will lead to a reduction in the value of existing investments, which were made based on the current market dynamics.

Additionally, extant forward contracts for future SRECs vintages were executed reflecting current and past market dynamics. If the SACP is reduced, many existing contracts will still reflect higher prices as lowering the SACP does not retroactively reduce previously negotiated contract values. Lowering the SACP may incentivize

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parties to perform an efficient breach of contract, which would result in multiple parties breaching their contractual obligations at the detriment of the market. Although many contracts in the industry cap their damages at the SACP, many more contracts base their damages on direct and actual damages calculated based on the market price of the product at the time of the breach, irrespective of any SACP cap. In other words, for contracts that do not cap their damages at the SACP, contractual damages will likely be in excess of the SACP. For compliance entities, this dynamic would likely result in a decision to continue to purchase SRECs above the reduced SACP rather than breaching their contractual obligations. These outcomes would result in direct harm to the solar industry, reduced confidence in the state's SREC market, and/or failure to resolve cost cap constraints where compliance entities must fulfill their existing contracts.

3Degrees recognizes and appreciates that the BPU seeks to balance multiple priorities in implementing the Solar Transition. It is imperative that any outcome not do harm to existing investments or thwart general confidence in the solar markets. Please do not hesitate to reach out with any questions, comments, or requests for further information.

Sincerely,

Maya Kelty

Maya Kelty
Director, Regulatory Affairs

TRUE GREEN CAPITAL

January 31, 2020

Via email: charles.gurkas@bpu.nj.gov

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue, 9th Floor
Trenton, New Jersey 08625

Re: Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps (Item#2: Cost Cap Calculations; and Item #3: Legacy Projects)

Dear Secretary Camacho-Welch:

True Green Capital Management LLC ("TGC") appreciates the opportunity to provide comments in the above referenced matter. By way of background, TGC is an investor in and owner of large scale distributed solar power generation plants in several states, including New Jersey. True Green Capital Management has been a significant and early investor in New Jersey's solar market with over 130 megawatts of solar power plants in its portfolio - representing an investment of approximately $235 million in the State.

We have reviewed the comments filed by NJR Clean Energy Ventures ("NJRCEV") in this matter and write to express our support of and general concurrence with the NJRCEV comments. We share NJRCEV's concern that there are major risks of irrevocably oversupplying the NJ SREC market to the significant determinant of legacy asset owners based on the final market closure rule. We reiterate that it is imperative that the BPU formalize its stated policy commitment to a stable and balanced SREC market no later than the date the SREC market is closed. If the BPU adopts a comprehensive approach to calculating the cost caps, as it has done consistently in other contexts, and employs a banking mechanism across compliance years as it empowered to do, then any restructuring of the legacy program can be achieved consistently with the requirements of the Clean Energy Act, P.L. 2018, c.17 that "prior investments retain value" and at levels that do not eviscerate the significant investments that have been made by TGC, NJRCEV and others in meeting New Jersey's clean energy goals. We believe that the BPU has a number of policy tools at its disposal to accomplish this end, many of them described in NJRCEV's comment letter, and we would welcome the opportunity to explore these further with Staff.

Thank you for the opportunity to provide comments to Staff's Straw Proposal. We look forward to the opportunity to actively participate in the ongoing Solar Transition proceedings.

Respectfully submitted,

PANOS NINIOS

Dr. Panagiotis Ninios
Managing Partner
True Green Capital Management LLC

Matthew M. Weissman
Managing Counsel - State Regulatory

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel : 973-430-7052 fax: 973-430-5983
email: matthew.weissman@pseg.com

PSEG Services Corporation

January 31, 2020

Via Overnight Delivery & E-mail (Charles.Gurkas@bpu.nj.gov)
Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 S. Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, NJ 08625-0350

Re: STAFF STRAW PROPOSAL ON DEFINING THE CLEAN ENERGY ACT OF 2018'S STATUTORY COST CAPS

Dear Secretary Camacho-Welch:

Public Service Enterprise Group, Inc. ("PSEG" or the "Company") appreciates the opportunity to provide comments on the January 6, 2020 Staff Straw proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps, Item #2 (how the Cost Caps should be determined and implemented) and Item #3 (reforms to the Legacy SREC program). PSEG supports the Board's efforts to seek input and to adopt rule details that are transparent and consistent with the statutory requirements of the Clean Energy Act's cost containment provision. The Company has been an active participant throughout the stakeholder process and hopes the Board finds these comments useful in implementing this important mechanism.

Regarding Item #2, calculation of the cost cap, PSEG believes that the Board should interpret the statutory language plainly and remain consistent with established practices for calculating costs of renewable energy requirements and expenses paid for electricity. Specifically, "the cost to customers of the Class I renewable energy requirement" that makes up the numerator of the Cost Cap Equation should be calculated in the same manner and using the same methods that the Office of Clean Energy has employed since 2005 when publicly reporting the costs of New Jersey's RPS in its annual RPS Report Summary, which is most recently available at:
https://www.njcleanenergy.com/files/file/rps/EY18/RPS%20Comp%20EY%202005-2018.pdf
The RPS cost calculation represents a methodology that is generally accepted by the industry for RPS compliance purposes.

Similarly, the Board should plainly interpret the "total paid for electricity by all customers in the State" that makes up the denominator of the Cost Cap Equation as the total amount collected from customers for electric sales made by New Jersey electric distribution companies ("EDCs"). PSEG recommends that the Board work with EDCs to identify how this information may be most efficiently and effectively reported to the Board for its use in calculating the cost cap.

While there may be other data sources, various inputs, and alternate methodologies that could be considered to derive the Cost Cap Equation, an overly complicated and/or brand new methodology would require more vetting by industry stakeholders with various interests and may not be readily accepted. This may delay implementation or even generate protracted legal challenges. By using readily available, simple, and generally accepted calculations, implementation of the CEA's Class 1 renewable energy programs could be more streamlined, enabling timely realization of the programs' goals and benefits.[1]

Regarding Item #3, PSEG believes that consideration of reforms to the legacy program at this time is premature, not necessary, and would be an inefficient use of Board staff and industry resources that should instead be fully dedicated to addressing the important issues related to the implementation of a solar successor program that are expressly set forth in the CEA. The solar market in New Jersey continues to be in a state of uncertainty, and while promulgation of final rules on the transitional solar program helps to alleviate short-term risks to project developers and owners, the market continues to need the certainty of a successor program to ensure the New Jersey solar market continues to grow and evolve.

In addition, reform of the legacy program prior to when the transition and successor programs are operational is of little value and may only add risk to the market. Even though prices are fixed, there are many uncertainties within the transition program. For example, how large will the population of projects be now that the Board has ruled that the window for entry will remain open until the successor program has been approved, how many projects in the development queue will advance to completion, and what will be the pace of project completion? Only once the Board begins to track the actual results of the transition program will answers to these questions, and their potential impacts to the cost cap, become apparent. These same questions exist for the successor program as well. PSEG recommends the Board exercise patience in considering changes to the legacy program until it has data on how all of these program are operating and an understanding of their collective impact on the State's ability to remain within the cost cap. Finally, making changes to the legacy programs could lead to legal challenges that could further drain resources that should be devoted to advancing the CEA. Absent a legislative mandate to reform the legacy program, PSEG recommends staying the course on the legacy program.

PSEG appreciates the opportunity to submit comments in this matter.

Very truly yours,

Matthew Weissman

Matthew M. Weissman

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[1] Notably, the Office of Legislative Services utilized the Board's RPS cost reports and data from the U.S. Energy Information Administration for the total paid for electricity by all New Jersey customers in estimating the CEA's renewable energy cap for the Legislative Fiscal Estimate report associated with the CEA. *Available at:* https://www.njleg.state.nj.us/2018/Bills/A4000/3723_E1.HTM (page 6).

amp

amp.energy

1550 Wewatta St, 4th Fl
Denver, CO 80202
United States

T +1 303.653.9805

January 30, 2020

Dear Secretary Phillips,

I am writing on behalf of Amp Solar Development, Inc., a solar developer, owner, and operator siting new community solar projects in New Jersey. Please consider our comments in response to Item #3, Reform of the Legacy SREC Program, of the Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps released on January 6, 2020.

1. Should Staff consider reforms to the SREC market in order to reduce the variability in potential SREC outcomes?

   Amp recommends that Staff consider mechanisms to reduce the variability of SREC prices. Fixed and long dated SREC prices will significantly help underwrite projects at a lower cost of capital which could allow for lower discounts to end customers (community solar program) or lower PPA rates to utilities or commercial customers.

2. Should owners of SREC contracts be required to take part in any restructuring of the program, or should participation be voluntary?

   Amp recommends that participation be voluntary.

3. Should Staff examine moving toward converting SRECs to a fixed price product, or would it be better to look at a lower Alternative Compliance Payment ("ACP") and the institution of a floor price or buyer of last resort?

   No response.

4. If Staff were to recommend setting a fixed price for SRECs, how should that price be set?

   No response.

5. If Staff were to look at a lower ACP and buyer of last resort program, how should such a program be structured?

   No response.

6. Should the Board consider a "tight collar"? How would such a program be implemented?

   No response.

7. Are there other reforms that Staff should consider?

   Amp recommends consideration of adders for brownfields or community solar gardens with >50% low-income or minority subscribers.

Sincerely,

Riley Hutchings
U.S. Policy Analyst

M: 503.277.8025
Skype: live:.cid.60daf693038d9c2
www.amp.energy

Environmental Markets Association
529 14th Street NW, Suite 750
Washington, DC 20045
www.emahq.org

New Jersey Staff Straw Proposal on
Clean Energy Act of 2018 Statutory Cost Caps ("Straw Proposal")

VIA ELECTRONIC DELIVERY January 31, 2020

Aida Camacho-Welch, Secretary
Board of Public Utilities
44 So. Clinton Avenue
Trenton, NJ 08625

Re: EMA Comments on New Jersey's Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps

Dear New Jersey Board of Public Utilities and Staff:

The Environmental Markets Association ("EMA") is pleased to help inform the design of New Jersey's solar transition as required by P.L. 2018, c.17 (the "Clean Energy Act"). EMA recognizes and appreciates the immense challenge that the New Jersey ("NJ") Board of Public Utilities ("BPU") has been assigned with in the implementation of the Clean Energy Act, particularly around the issues of the cost cap and the desire to promote solar growth in the State, while cost-effectively achieving a 50% renewable portfolio standard ("RPS") by 2030.

EMA is comprised of local, regional, and national member companies that have participated in NJ's Class I renewable energy certificate ("REC"), Class II REC, and solar renewable energy certificate ("SREC") market programs since inception, including early engagement in the actual setup and implementation of the original renewable portfolio standard ("RPS") and NJ SREC program. EMA Members have worked extensively to achieve the program's targets and continue to interface with the RPS in multiple ways (e.g., as retail electricity suppliers, basic generation service providers, REC traders, REC brokers, REC marketplaces, REC aggregators, and as renewable energy project developers and investors).

Thank you for your consideration of our comments attached in Appendix A. <u>EMA's answers here are limited solely to item #3 and discuss our rationale as to why we strongly discourage the BPU from taking any actions to reform or restructure the existing NJ SREC market since this will undermine the market's integrity and result in significant contractual and financial damages for New Jersey's clean energy industry</u>. Previous comments filed by the EMA may also offer the BPU useful guidance on this proceeding. The EMA is ready to offer any additional assistance as needed by the BPU as New Jersey moves toward its clean energy future.

Sincerely,

Christian Hofer

Christian Hofer
EMA Board Director & Market Principles Committee Chair
Environmental Markets Association
Ph: (203) 856-6485

Appendix A – Answers to Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps

Item #3) explore reforms to the Legacy SREC program that ensure a robust solar market while conforming to the statutory limitations on cost.

1. **Should Staff consider reforms to the SREC market in order to reduce the variability in potential SREC outcomes?**

No. EMA believes that Legacy SRECs must remain "deliverable" as NJ SRECs under any regulatory proceeding outcome. Any change to the ability of participants to deliver NJ SRECs into bilateral (over-the-counter) spot and forward sale contracts will cause the industry significant financial harm. EMA therefore strongly discourages any regulatory actions that would preempt or eliminate the "deliverability" of SRECs under the existing regulatory framework. For example, NJ SREC deliverability could be impacted by a modification of the program that retroactively eliminates the SREC program in exchange for a fixed fee, fixed tariff, or any other type of tariff-based program to compensate existing NJ SREC investors that does not involve the delivery of NJ SRECs. NJ SREC deliverability could also be impacted by subsuming the Legacy SREC program into a successor program which changes the nature of the NJ SREC "product" name or specification. This would cause substantial financial harm to NJ's solar energy industry overnight and would lead to significant solar job layoffs and irreversible harm to many solar energy project owners and developers. If NJ SRECs were to become "undeliverable" due to regulatory action, which include actions that would lower the alternative compliance payment schedule, this would cause the NJ solar energy industry significant harm by impacting SREC forward sale contracts and project finance agreements. This would lead to significant contractual damages, the evaporation of contracted cashflow for projects already built, and investor defaults in the debt and equity space. This result would be counterproductive to the objectives and intent of SREC Transition Principles #3. The Legacy NJ SREC market structure must remain intact as currently legislated.

2. **Should owners of SREC contracts be required to take part in any restructuring of the program, or should participation be voluntary?**

No. See answers in question #1. Participation must only be voluntary if any such proposal is pursued. No actions must be taken that impact the deliverability of an SREC or invalidate bilateral over-the-counter forward sale contracts that exist in the market.

3. **Should Staff examine moving toward converting SRECs to a fixed price product, or would it be better to look at a lower Alternative Compliance Payment ("ACP") and the institution of a floor price or buyer of last resort?**

No. See answers in question #1. The EMA believes that the existing structure of the tradable and competitive NJ SREC market is consistent with the legislative requirement of paragraph l. of Section 38 of P.L.1999 to place greater reliance on competitive markets:

2. Section 38 of P.L.1999, c.23 (C.48:3-87) is amended to read as follows:

EMA Environmental Markets Association

Environmental Markets Association
529 14th Street NW, Suite 750
Washington, DC 20045
www.emahq.org

> l. The board shall implement its responsibilities under the provisions of this section in such a manner as to:
>
> (1) place greater reliance on competitive markets, with the explicit goal of encouraging and ensuring the emergence of new entrants that can foster innovations and price competition;

4. **If Staff were to recommend setting a fixed price for SRECs, how should that price be set?** **This is not a recommended course of action**. Please see answer in question #1.

5. **If Staff were to look at a lower ACP and buyer of last resort program, how should such a program be structured?** **This is not a recommended course of action.** Please see answer in question #1.

6. **Should the Board consider a “tight collar”? How would such a program be implemented?** **This is not a recommended course of action.** Please see answers in question #1.

7. **Are there other reforms that Staff should consider?** **No.** Please see answer in question #1.

Appendix B – Best Practice Principles for Renewable Energy Certificate Markets

Environmental Markets Association
529 14th Street NW, Suite 750
Washington, DC 20045
www.emahq.org

Best Practice Principles for Renewable Energy Certificate Markets

The Environmental Markets Association (EMA) is focused on promoting market-based solutions for environmental challenges through sound public policy, industry best practices, effective education and training, and member networking. EMA represents a diverse membership including large utilities, renewable energy certificate (REC) traders and brokers, financial exchanges, law firms, project developers, investors, consultants, academics, non-governmental organizations, and government agencies. EMA strongly supports the utilization of markets to achieve environmental policy goals. Well-designed markets yield many benefits including, but not limited to, transparent price signals determined through competition, risk mitigation opportunities, incentives for technological innovation, efficient allocation of capital and resources, investor certainty, and ratepayer protection. In support of RPS objectives, EMA endorses the following set of Best Practice Principles for REC Markets:

Best Practice Principles for REC Markets

1. **Tradable RECs**
2. **Market-Based Pricing**
3. **Market Design That Fosters Transparency, Competition, and Liquidity**
4. **Market Oversight**
5. **Market Integrity and Stability**

In the case of Renewable Portfolio Standards (RPS), EMA believes that market-based programs will enable the most cost-effective, flexible, and innovative approach to maximizing renewable energy. EMA further believes that this is best accomplished through open, transparent, and competitive markets, and the use of tradable RECs as the primary means of RPS compliance. As such, well-designed RPS policies and REC markets offer stakeholders many advantages toward achieving their economic, social, and environmental objectives:

RPS Advantages from Best Practice Principles

- ✓ **Accountable Policy Objectives**
- ✓ **Pricing Transparency**
- ✓ **Compliance Flexibility**
- ✓ **Policy Cost-Effectiveness**
- ✓ **Ratepayer Protection**
- ✓ **Market Integrity & Stability**
- ✓ **Investor Certainty**
- ✓ **Information Feedback Signals**
- ✓ **Market Efficiency & Liquidity**
- ✓ **Financial Innovation**
- ✓ **Lower Costs of Capital**
- ✓ **Diverse Participant Bases**

For additional information about these Best Practice Principles for Renewable Energy Certificate Markets and their RPS advantages, please view our Supplemental Guidance Document for REC Markets here.

Appendix C – Supplemental Guidance Document

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529 14th Street NW, Suite 750
Washington, DC 20045
www.emahq.org

Supplemental Guidance Document
Best Practice Principles for Renewable Energy Certificate Markets

1. Tradeable RECs

- EMA supports the use of tradeable RECs for renewable portfolio standard (RPS) compliance. Clearly defined tradeable RECs (e.g., by vintage period, useful life, resource and compliance eligibility) provide a means for facilitating commercial transactions through bilateral markets that enable participants to trade RECs on the spot market (for immediate delivery) and in the forward market (for future delivery). Spot markets facilitate the monetization of RECs. Forward markets facilitate the management of risk. Bilateral REC markets occur when participants trade directly among each other outside of a centralized procurement or auction process. RECs obtained at auction can be later resold through bilateral markets.
- Tradable RECs allow for market participants, who may not have entitlements or compliance obligations, to provide market liquidity and risk management services to those entities with future entitlements to the product (e.g., renewable resource developers) and to those entities with future compliance obligations (e.g., load-serving entities).
- Open and competitive REC markets attract a more diverse participant base, which in turn increases market liquidity. For renewable resource developers, this translates into more counterparties to purchase RECs. For compliance entities, this means more flexibility to procure RECs at times, and in volumes, that match RPS obligations. For all market participants, this results in more avenues to meet specific transactional needs and credit requirements. Open and competitive markets are essential to creating efficient REC price discovery and liquid trading on a forward basis (i.e., for future compliance vintages).

2. Market-Based Pricing

- EMA supports the price discovery of RECs through market-based mechanisms as opposed to the assignment of prices through administrative processes by government agencies. Collectively, REC trading participants will always have access to more information through markets. As such, the formation of REC prices should be driven by information and competition that accounts for the economic and risk preferences of market participants.
- Market-driven REC prices provide transparent and dynamic economic signals to participants for investment and resource allocation decisions. This enables efficient compliance by helping participants to dispatch the lowest cost solutions that fulfil the RPS.
- RPS design that allows for "floating" REC prices that can respond in real-time to new information is an important concept. Allowing prices to adjust in real-time to changes in supply and demand and other existing policies (e.g., the Public Utility Regulatory Policies Act, net energy metering, and tax law) guides

the market towards the most cost-effective achievement of RPS objectives. Benefits include ratepayer protection and the establishment of reference prices for financial innovation:

- Ratepayer Protection – While high REC prices are a signal to invest, low REC prices are a signal to slow the development of new resources vs. current RPS targets established by law. Allowing prices to fall when renewable technologies become cheaper, when other policy-based incentives are at play, or when markets become oversupplied is critical to protecting ratepayers from unnecessary or irresponsible investment and forces market participants to be more thoughtful about expenditures, risk management, and resource allocation. If investments exceed stated regulatory targets, or are negatively impacted by company governance or exogenous market factors, ratepayers are protected from investment losses. This supports overall market efficiency.
- Financial Innovation – Tradable RECs priced by vintage create reference prices for both physical and financial REC contracts (e.g., forward and futures contracts, respectively) that can be used to facilitate project investment through contracted revenue and to manage price risk. By helping to lower the risk of an economic activity, or by giving market participants tools to transfer risk, the availability of financial products can lower the cost of capital for renewable resource investments. This supports lower REC prices and lower RPS costs.

- Generally, the more compliance entities, producers, market makers, and financial participants that take part in a market, the more effective that market will be in facilitating price discovery, price transparency, market liquidity, and the efficient allocation of resources. Centralized compliance obligations with a single entity or a small group of entities should be avoided, if possible, to decrease the risk of market manipulation and increase market liquidity. Likewise, central procurement mechanisms that do not take advantage of the benefits from competitive market participation should be avoided or minimized.

3. Market Design That Fosters Transparency, Competition, and Liquidity

- Transparency, competition, and liquidity are mutually reinforcing market phenomena that will help promote the cost-effective achievement of RPS policies. The more cost-effective resources become at fulfilling RPS targets, the higher that RPS targets can be set without adversely impacting ratepayers.
- EMA supports market design features that create transparent and reliable price signals capable of facilitating market or auction objectives that channel RECs to participants who most highly value them.
- RPS design components should ensure that all participants have both an incentive and interest to ensure that efficient price discovery occurs and is revealed to the market in a timely and transparent manner.

- If design components include features such as price boundaries, such as alternative compliance payments (ACPs) or price floors, such features must be transparent to market participants on a forward-looking basis, must facilitate competitive market outcomes, and must support the integrity of the market. Statutory price floors in and of themselves will not necessarily support pricing or liquidity in an oversupplied market without an additional back-stop mechanism or capitalized facility.
- EMA supports market design that enables diverse participation and competition in environmental markets, since a competitive market reduces liquidity risk and ensures that no one entity can unduly influence the market.
- Any regulation should be carefully evaluated as to its impact on market liquidity, transparency, competition, and costs to participants. EMA does not support efforts to limit participation in REC markets or REC auctions to only those entities with compliance obligations.

Key RPS Design Components and REC Market Features

RPS Component	REC Market Feature
REC Tier / Class Product Definitions	▪ REC tier / class product definitions include technology type, generator vintage (i.e., online) eligibility dates, and other environmental attribute considerations. ▪ REC tiers within an RPS should be clearly defined to distinguish between existing and new entry renewable resources, which may require different revenues to adequately account for different cost-recovery rates. ▪ Each REC tier will have its own distinct REC market if it has a unique ACP schedule and requires obligated entities to fulfill compliance targets with REC purchases. Although REC tier pricing may be influenced indirectly by other REC markets in jurisdictions that have resource eligibility overlap, it will exhibit unique supply / demand fundamentals and price signals to market participants. ▪ If separate RPS tiers are created to support less commercialized technologies, or to accelerate already commercialized technologies that provide unique RPS benefits, these tiers should be additional to other technology tiers and each tier should deploy best practice market design principles if possible and cost-effective. ▪ REC standard of units (e.g., megawatt hours of power generation per single REC issuance) should be clearly defined and to the extent possible, standardized with adjacent RPS jurisdictions. ▪ REC tiers should be clearly defined as to whether they are carve outs of another tier, or a set aside (an additional, cumulative, target) within the overall RPS.
Vintage Periods	▪ Vintage period should be clearly defined in regard to the span of dates in which generation from an eligible resource can issue a compliance-eligible REC for use in a particular compliance year(s). Calendar Year and Energy Year is common. ▪ Vintage-based compliance periods ensure RPS policy accountability through periodically verified REC retirements (annual retirements are encouraged).

Supplemental Guidance Document
Best Practice Principles for Renewable Energy Certificate Markets

Compliance Eligibility	▪ REC tiers should be clearly defined in regard to which resources can generate compliance-eligible RECs for compliance. ▪ Compliance-eligible REC vintages for a given reporting year (e.g., RY2018) should also be clearly defined (this is often referred to as REC banking or useful life). ▪ Compliance due dates for REC retirements should be clearly posted and have administratively straightforward reporting processes. ▪ ACP payments should be required in a timely manner following the end of an RPS compliance requirement year.
Resource Eligibility	▪ Broad RPS technology eligibility among a diverse array of clean energy technologies is encouraged. ▪ The more technologies that are RPS eligible, the greater the number of potential REC producers in a market and the greater the competitive pricing benefits (e.g., economic and employment) across multiple industries. Allowing multiple technologies to compete for grid access also supports electrical grid fuel diversity and resiliency. ▪ Resource eligibility has an extremely high impact on the supply / demand fundamentals of a REC tier and therefore a high impact on whether a market exhibits low or high REC pricing vs. the ACP schedule. ▪ The number of vintage periods a generator is certified to issue RECs for RPS compliance within a particular REC tier (sometimes referred to as "qualification life"), should be clearly defined in advance, even if only to confirm that no vintage eligibility limitations apply to RECs issued by RPS certified generators. ▪ Generator vintage eligibility (the date in which a generator is considered to have come on line for the purposes of an RPS) should be clearly defined for each REC tier within an RPS.
Geographic Eligibility	▪ Geographic, or jurisdictional, eligibility of renewable resource generators should be clearly defined for each REC tier. A narrow definition of geographic eligibility is in-state located resources. A broad definition is national eligibility. Variations exist for adjacent state and regionally located resources. ▪ Geographic eligibility has an extremely high impact on the supply / demand fundamentals of a REC tier and therefore a high impact on whether a market exhibits low or high REC pricing vs. the ACP schedule. ▪ REC import eligibility (with or without the energy transfer) has an extremely high impact on the supply / demand fundamentals of a REC tier and therefore a high impact on whether a market exhibits low or high REC pricing vs. the ACP schedule.
Fixed RPS Compliance Targets and Forward-Looking RPS Schedules	▪ First, RPS compliance schedules should be fixed at pre-set percentage levels of retail electricity sales in advance of compliance years. EMA recommends that RPS targets (and therefore compliance action) step up annually according to a pre-set schedule that is transparent to market participants. Percentage-based targets ensure that REC demand is responsive to load variation, which provides an additional cost-containment mechanism to ratepayers in the event of load decline or ensures that as load grows so does the mix of renewable resources and associated clean energy benefits.

Supplemental Guidance Document
Best Practice Principles for Renewable Energy Certificate Markets

	▪ Second, RPS compliance year schedules should have tenor (i.e., be transparently established as far into the future as possible) to support long-term market and investment certainty. This creates transparency and is important to enabling tradability and investor confidence. ▪ Third, RPS target terminal years (sometimes referred to as sunset language) should be clearly defined. Terminal year RPS targets should always be maintained at their final levels (i.e., the procurement percentage should not drop down to zero or begin to decline once achieved) to ensure that RECs generated from investments post the last compliance year can continue to be sold and delivered to compliance entities and that the overall penetration of renewables in the electricity mix continues to comply with the law. ▪ Fourth, under no circumstances should a compliance year's RPS target ever be set lower than any previously established compliance year target.
Fixed Alternative Compliance Payment (ACP) Rates and Forward-Looking ACP Schedules	▪ ACP mechanisms are a pre-requisite for REC market trading and timely, accountable, RPS compliance, since they create penalties on obligated entities for failing to procure and retire RECs. ▪ ACP rate schedules should be forward-looking and align with the RPS compliance year schedules (on a vintage-by-vintage basis) to support long-term market certainty. This creates transparency and is important to enabling investor confidence, a lower cost of capital, and cost-effective RPS achievement. ▪ ACP rates should be fixed and set at sufficiently high enough levels that both encourage renewable energy investment and market tradability / liquidity. High ACP rate schedules should not be interpreted to imply high RPS compliance costs. ▪ Whenever possible, ACP rates should be set at levels which reflect regional circumstances to address REC shuffling / attrition between RPS jurisdictions. ▪ ACP payments should also be required after each compliance year and payments should be required in a reasonable timeframe. ▪ Non-published ACP schedules, or opaque formulas pegged to complicated calculations or market pricing, creates market uncertainty and should be avoided. ▪ ACP rates should be the only cost-containment mechanism built into an RPS. Other forms of cost-containment mechanisms, such as when an RPS freeze is tied to electricity price increases beyond a certain percentage threshold create considerable investment uncertainty and should be avoided. ▪ Reductions to ACP schedules post establishment is strongly discouraged. If ACP schedules are adjusted downward, considerable thought should be given as to the lower ACP schedules impact on pre-existing investments and forward sale REC contracts (which may become invalidated by change-in-law provisions). ▪ The general use of ACP proceeds should be disclosed to market participants. Policymakers that want to limit the impact of ACP payments on ratepayers can implement a pro-rata bill credit based on total ACP proceeds to ease RPS costs in short supplied markets.
Applicable Electricity Sales and Exemptions	▪ Applicable retail sales, exemptions, and the obligated entities required to procure for RPS compliance should be clearly defined.

	▪ Generally, electricity exemptions, which reduce total applicable retail sales applied to RPS requirements, weaken demand for renewable resources, may create uncertainty in calculating REC demand, and may mislead the public about published RPS targets.
REC Banking (Useful Life)	▪ Clearly defined banking of RECs (useful life) is encouraged. Banking of RECs helps facilitate a more efficient market by ensuring that RECs issued in previous years maintain value long enough for participants to transact them. o For producers, this gives them the option to hold RECs into fundamentally short years, which defers current cashflow in exchange for the potential to earn a higher price later. o For compliance entities, this gives them the opportunity to bank lower cost RECs from oversupplied years into fundamentally undersupplied years, thereby providing the option to manage their compliance costs in response to the market environment or specific capital / credit constraints.
REC Multipliers, Factors, and Forward Crediting (Borrowing)	▪ Multipliers provide higher incentives to projects through awarding each megawatt hour of generation a greater proportional amount of RECs. All else equal, this increases the amount of revenue a project receives for the same unit of production, but dilutes published RPS targets and may lower REC pricing through increased supply. The use of REC multipliers should be weighed against the potential for market distortion and decreased market liquidity. ▪ Factors provide lower incentives to projects through awarding each megawatt-hour of generation a lower proportional amount of RECs. All else equal, this lowers the amount of revenue a project receives for the same unit of production. Factors have the potential to create economic attribute waste (i.e., clean energy generation that does not count towards RPS achievement but still provides environmental benefits) if the non-factor proportion of generation cannot issue other RECs saleable for RPS compliance. REC factors should be avoided if they apply to the main, or overarching, tier of an RPS. ▪ Multipliers and factors must be considered carefully as they have wide ranging impacts on different project segments (e.g., utility, commercial, residential). If implemented improperly, they can distort market pricing and make the market allocate capital less efficiently, meaning power purchasers (and ultimately end-users or ratepayers) pay more for electricity. In practice, this can cause expensive projects to deploy at the expense of economically more efficient new entry units (for example, smaller but higher cost projects which have access to net energy metering at retail rates vs. larger but lower-cost projects with economies of scale that must compete in the wholesale markets). Multipliers can end up weakening overall RPS targets if implemented poorly. ▪ Forward Crediting, or the borrowing of RECs from future production periods that can be sold today, distorts market pricing and should not be deployed in any environmental market. Since REC issuance and cashflow would occur upfront with forward crediting, this decreases the incentive to maintain the project and increases the risk that the project will not deliver its RECs for future RPS compliance. Forward crediting runs the risk of creating an artificially

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	oversupplied REC market with lower prices that subsequently damages the investment signal participants require to develop new resources.
Long-term Contracting Programs	▪ Tradable RECs and long-term contracting programs can successfully coexist; however, long-term contracting programs should not be legislated in replacement of, or at the expense of, open and competitive tradable REC markets that go above and beyond the designated contract volumes in the long-term contracting programs. ▪ Long-term contracting programs that award a REC offtake contract in advance of when a generator comes online should make sure that adequate financial security is posted until the project comes online. This will discourage bidders from bidding into procurements with unrealistic economic assumptions that tie up scarce resources (i.e., contract awards) that may prevent other, more viable, projects from being developed.
RPS Reporting	▪ RPS compliance reports should be written and released to the public for each requirement year on a timely basis. Wherever possible, RPS compliance reports should provide sufficient data (e.g., on applicable retail electricity sales and exemptions, RECs retired, RECs banked forward, etc...) that is helpful to participants in assessing the status of the RPS and its REC markets.
Interaction with Compliance Carbon Cap-and-Trade Programs	▪ REC markets and carbon allowance / carbon offset markets can coexist in the same jurisdictions. Current best practice keeps fungibility separate (i.e., RECs cannot be used for carbon market compliance and carbon allowances / carbon offsets cannot be used for RPS compliance). Clear and thoughtful definitions of which environmental attributes are embodied by each environmental commodity can help eliminate confusion between market participants and regulators while promoting market liquidity.
Private Investment	▪ Market design should foster private investment and market participation. ▪ Leveraging private investment and capital markets in achieving RPS policy is important. Well-designed RPS policies and competitive REC markets will shift investment risk away from ratepayers or taxpayers to private investors. If a project fails, it does not receive cost-recovery through REC payments (because it does not generate any RECs). If a project receives a lower investment return because of overly optimistic REC price forecasts, ratepayers are shielded from this economic miscalculation.

4. Market Oversight

- EMA supports clearly-defined independent market oversight, with stakeholder input, to maximize the benefits of competitive commercial behavior in achieving policy goals and providing transparency, while guarding against fraud and manipulation and minimizing systemic risk. Successful RPS design must include measures that protect the market from activity that is illegal or detrimental to the market's function.

Environmental Markets Association
529 14th Street NW, Suite 750
Washington, DC 20045
www.emahq.org

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- EMA supports independent oversight of the market structure and operation, which may include periodic review, and as needed, recommendations with stakeholder input for addressing any identified market design flaws.
- Over-the-counter spot and forward REC contracts currently qualify for the forward exclusion definition of a "swap" under the Commodity Exchange Act (CEA) if intended for physical delivery. As such, RECs are classified as non-financial commodities by the Commodity Futures Trading Commission (CFTC) and regulated accordingly under the CEA. Financial REC futures and options contracts are regulated by the CFTC and must trade on an approved commodity exchange.

5. Market Integrity and Stability

- RPS laws, regulations, and regulatory guidance documentation should strive to maintain the integrity of REC markets and RPS policy in all aspects. Long-term regulatory and policy certainty will allow a robust market-based system to evolve with healthy price discovery and liquidity. Flawed market design rules, even minor ones, can have a harmful impact on market liquidity and increase RPS compliance costs. When establishing and enforcing local preferences (e.g., resource eligibility, generator vintage eligibility, biomass emissions limits) regulators should be careful not to interfere directly with a market's price discovery process. RPS frameworks mobilize private investment that generates environmental and economic benefits. Long-term certainty and stability in the political institutions can help lower the cost of capital by instilling integrity in the regulatory commodity.
- Frequently changing rules creates investment uncertainty and can stifle market development. Regulatory policy changes that are applied retroactively to a market (such as the lowering of an ACP schedule once established or the retroactive decertification of previously qualified RPS generators) damage investor confidence and should be avoided. Vague or ambiguous regulatory language also damages investor confidence, all of which increases the cost of capital for renewable energy investments.
- High, low, or volatile REC pricing, at points in time, should not be interpreted as a sign of market failure. Prices, in essence, represent information. In competitive tradable markets, when information changes, prices change. Indeed, price fluctuations are an indication of a healthy market that is responding to information and adjusting to changing operating conditions. When RPS policies are well-designed, high REC prices will encourage the development of new renewable energy resources that in turn eventually lowers market pricing and vice versa.

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- Tradable RECs support accountable policy objectives and information transparency by ensuring that RPS achievement is measured, tracked, and reported on in a timely manner. EMA supports the usage of secure and robust tracking mechanisms and methodologies to provide certainty of REC ownership. Well-implemented REC registry systems will avoid double counting of RECs and the dilution of RPS benefits. Failure to implement a system to track ownership of environmental compliance products can undermine the success of the market. Developing such registry mechanisms and methodologies must be a part of the market design process and must be completed prior to implementing any new REC market. Any issues with attribute ownership, claims of benefits, or means of tracking the RECs must be clarified before the start of any program. Failure to do so can greatly undermine confidence in the market, stifle liquidity, and hinder the program's full potential of benefits.
- EMA supports legislative, regulatory, and rulemaking efforts to establish stable, clearly-defined, and transparent market regimes. EMA promotes the inclusion of experienced market participants at all stages of the development process and post-implementation market review process in order to contribute to the overall strength and vibrancy of the markets. Both the design process and the post-implementation review process must be transparent to all stakeholders.
- Maintaining market integrity is the responsibility of both market participants and regulators.

About EMA

EMA is a U.S.-based trade association representing the interests of companies that are involved in the trading, legislation, and regulation of environmental markets. EMA was founded in 1997 as a 501(c)(6) not-for-profit organization. Our members have decades of extensive, first-hand experience with market instruments related to Federal and regional cap-and-trade programs in SO2, NOx, and GHG emissions as well as state-driven RPS programs throughout the U.S. The EMA represents a wide variety of participants in the clean energy markets, from utilities and load-serving entities to renewable project developers and investors. EMA members have extensive operational experience with RPS compliance, REC trading, and renewable energy investment and, collectively, have made significant historical contributions to achieving state RPS targets. The EMA has a vested interest in the continued success of market-based mechanisms and RPS programs throughout the U.S. and encourages active discussion and collaboration among all industry participants. Inquiries about the EMA, or these Best Practice Principles for REC Markets may be directed here.

Jersey Central Power & Light
A FirstEnergy Company

300 Madison Avenue
Morristown, NJ 07962

Joshua R. Eckert, Esq.
(973) 401-8838
(330) 384-3875 (Fax)

January 16, 2020

VIA ELECTRONIC MAIL ONLY

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
P.O. Box 350
Trenton, New Jersey 08625
solar.transitions@bpu.nj.gov

Re: JCP&L Comments in Response to Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps

Dear Secretary Camacho-Welch:

Jersey Central Power & Light Company ("JCP&L" or the "Company") thanks the New Jersey Board of Public Utilities (the "Board") for the opportunity to provide comments on the straw proposal to define the statutory cost caps ("Cost Caps") in the Clean Energy Act of 2018 ("CEA"), provided by the Board's Staff on January 6, 2020 (the "Straw Proposal"). The CEA places a cap on the total annual costs that New Jersey's ratepayers are required to pay for Class I renewable energy requirements beginning in 2020. The Straw Proposal is intended to guide the Board in its development of the solar market in New Jersey, while remaining in compliance with the statutorily mandated cost caps. JCP&L offers these comments in recognition of the Board's conflicting goals to support the development of solar projects while continuing to reduce the costs of these subsidies to ratepayers.

The CEA, under section 38(d)(2), indicates *"... the board shall ensure that the cost to customers of the Class I renewable energy requirement imposed pursuant to this subsection shall not exceed nine percent of the total paid for electricity by all customers in the State for energy year 2019, energy year 2020, and energy year 2021, respectively, and shall not exceed seven percent of the total paid for electricity by all customers in the State in any energy year thereafter."* The Straw Proposal seeks comments on whether the Board should adopt a multi-year approach to compliance with the cost cap, including the use of a "banking mechanism" to allocate available cost cap "headroom." Staff defines "headroom" as the gap between the statutory cost cap in a given energy year and the total customer expenditures on the Class 1 renewable energy requirement during that energy year. In doing so, Staff seeks to determine whether the Board can satisfy the provisions of the CEA by determining compliance with the cost caps on a rolling basis by using average expenditures over time or by transferring cost cap headroom between energy years.

The Staff's view is that an alternative mechanism for determining compliance could facilitate the task of ensuring that total costs to ratepayers remain under the cap over the life of the program.

As part of the stakeholder input request, Staff has posed the following five questions pertaining to the use of headroom in subsequent years:

1. Should the Board adopt a true-up banking methodology so that any expenditures above or below the Cost Cap in one Energy Year are carried forward to a subsequent year?
2. Would allowing for banking between Energy Years affect the total ratepayer impact?
3. Should the Board consider averaging costs over a period in order to more accurately reflect total compliance costs, while smoothing transient effects? How would such an average be constructed?
4. Should the Board adopt a true-up banking mechanism that can utilize unspent headroom from previous years as well as anticipated/projected headroom from future years?
5. How should the accounting for such transfers be done?

As an initial matter, JCP&L would first point out that the CEA clearly provides that the cost cap is an annual limit that is applicable to each specific energy year and does not contemplate transferring or borrowing from year to year any amounts over or under the cost caps. The language clearly indicates the cost cap is to be applied to each specific energy year "respectively," which would indicate the intent is to have a specific cost cap for each specific year. There was not contemplation of any averaging of expenditures over multiple years nor any carry-forward or backward of any so-called "headroom". Accordingly, in response to the first question, the Company suggests that there be no adoption of a true-up banking methodology to transfer any amounts below or above the annual cost caps to any subsequent year, nor any provision to average annual cost. Adoption of such a mechanism would allow the costs for Class 1 compliance to exceed the cost cap set for a given energy year, which is in clear violation of the CEA's mandate that the Board "shall ensure that the cost to customers of the Class 1 renewable energy requirement . . . shall not exceed the [statutorily provided percentage] of the total paid for electricity by all customers in any energy year thereafter." Moreover, the CEA does provide the Board with other avenues to prevent the exceedance of the annual cost caps, including the ability to adjust the Class I renewable energy requirement.

In response to the second question, allowing for banking between Energy Years will affect the total ratepayer impact. In instances where the annual cost cap is not reached, allowing the carryforward of any available "unspent costs" would simply result in additional costs being incurred overall. Staff opines that allowing this "banking" mechanism would serve to ensure that total costs to ratepayers remain under the cap over the life of the program. However, this would also lead to higher costs over the program's life than simply applying the cost cap on a strict year to year basis, as mandated by the statutory language. This higher program cost would directly affect the ratepayers with increased overall cost of compliance.

The Company answers questions 3 and 4 collectively, as the subjects of both are viewed as impermissible under the CEA. The Company believes that both, averaging of costs over a program year and a true-up banking mechanism to reallocate headroom from year to year, will simply lead to overall higher program costs for the program lifetime. Solar developers understand their market, and they know what level of activity is achievable under the established annual cost caps. Market competition is the proper mechanism to drive compliance costs lower. If solar developers cannot install enough projects in an annual period that would result in compliance costs approaching the cost cap, there should be no reason to carry forward this capacity under the cost caps to a future year. Likewise, if over building leads to meeting or exceeding an annual cost cap, market forces would then dictate that pricing for renewable energy credits to meet renewable portfolio standards compliance requirements should decline.

JCP&L thanks the Board for the opportunity to provide these comments. Please do not hesitate to contact me should you have any questions.

Very truly yours,

Joshua R. Eckert
Counsel for Jersey Central Power & Light Company

Constellation.
An Exelon Company

January 16, 2019

Via Electronic Mail

Hon. Aida Camacho-Welch
Secretary of the Board
Board of Public Utilities
44 South Clinton Avenue
3rd Floor, Suite 314
PO Box 350
Trenton, New Jersey 08625-0350

Re: State Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps

Dear Secretary Camacho-Welch:

Constellation NewEnergy, Inc. ("Constellation") submits these comments in response to the New Jersey Board of Public Utilities ("BPU" or the "Board") Notice issued on January 6, 2020 in the above-referenced proceeding (the "January 6 Notice").

In the January 6 Notice, the Board requested that stakeholders first provide comments on whether the Board should employ a banking mechanism to administer the Cost Caps, and later provide comments on the determination and implementation of Cost Caps and on reforms to the Legacy SREC Program.

Constellation anticipates having additional comments related to the use of a banking mechanism to administer the Cost Caps after the Board has finalized the process by which Cost Caps will be determined and implemented. Until that time, it is difficult to address the question of banking, as the consequences of any one approach cannot fully be assessed in the absence of further information.

Constellation appreciates the Board requesting stakeholders input on these issues and hopes the question of using a banking mechanism to administer the Cost Caps will be re-visited once we have further details about calculation and implementation of Cost Caps. Should you have any questions about the foregoing, please do not hesitate to contact me at jesse.rodriguez@exeloncorp.com or (610) 765-6610.

Sincerely,

/s/

Jesse A. Rodriguez
Director, Energy Policy Analysis

January 16, 2020

Charles Gurkas
New Jersey Board of Public Utilities
Post Office Box 350
Trenton, New Jersey 08625

Re: **Comments of the Mid-Atlantic Renewable Energy Coalition on New Jersey's Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps**

Dear Charles Gurkas,

The Mid-Atlantic Renewable Energy Coalition (MAREC) appreciates the opportunity to provide these comments in response to the January 6, 2020 notice, which included the New Jersey Board of Public Utilities' (BPU) *Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps* (Straw Proposal).

Introduction

MAREC is a non-profit organization that was formed to help advance the opportunities for renewable energy development primarily in the region where the Regional Transmission Organization, PJM Interconnection (PJM), operates, including New Jersey. MAREC members have developed, owned, and operated thousands of megawatts of renewable energy serving the PJM territory.

MAREC members consist of utility scale wind and solar developers, wind turbine manufacturers and non-profit organizations dedicated to the growth of renewable energy technologies. It is due to this dedication that we have paid special attention to the New Jersey Solar Market Transition, as the health of one market will have rippling affects across our region.

MAREC applauds Governor Murphy and the legislature for setting ambitious goals of having New Jersey running on 100% clean energy by 2050 and 50% clean energy by 2030. To make the goals of the Energy Master Plan (EMP) a reality, the Board must act now -- *deliberately and wisely* -- on energy policy reforms. The decisions made at this point, at the beginning of the path to 50% and 100% clean energy, will "set the stage" for the future acceleration of the renewables market.

Careful consideration will be needed by the BPU in order to “get it right” relative to ratepayers and the State’s greenhouse gas and renewable goals. There are a host of critical issues that require further deliberation including, but not limited to, setting the right incentive levels; adopting a reasonable calculation of “space” under the rate caps; setting an appropriate glidepath to 100% renewables; and a host of other issues.

As requested in the notice, these comments apply to Item #1 – Treatment of Cost Cap “Headroom” in the Clean Energy Act only. We will also be submitting comments on Items #2 and #3 by the required deadline set forth in the notice.

To promote stability in the solar and Class I markets, as well as protect ratepayers, Cost Cap Headroom should be averaged over a 5-year period. This will mitigate the impacts of short-term cost volatility that could otherwise disrupt the Governor’s continuing efforts to promote the stable growth of New Jersey’s renewable energy development, which is required to achieve the State’s clean energy and environmental goals.

Responses to the five questions posed in the Straw Proposal regarding the treatment of headroom are provided below.

1. **Should the Board adopt a true-up banking methodology so that any expenditures above or below the Cost Cap in one Energy Year are carried forward to a subsequent year?**

Yes, the Board should adopt a true-up banking methodology that addresses unneeded uncertainty that harms market development while protecting ratepayers. A yearly calculation of single-year rate impacts is burdensome from a regulatory and process perspective and not needed to protect ratepayers. Calculating and truing up over a five-year period will protect ratepayers and advance the interests of the State to support and advance renewable development. This approach will establish a clear and stable mechanism to support market stability and further renewable development.

2. **Would allowing for banking between Energy Years affect the total ratepayer impact?**

Yes, banking across five Energy Years would mitigate market volatility and reduce future RPS uncertainty that is ultimately borne by ratepayers. Without banking, cost cap limits could be triggered due to single-year events that could be unrelated to renewable development (for example, a one year down turn in capacity prices could trigger a rate cap exceedance in one year) and would create market uncertainty and investment risk resulting in unnecessary increases to long-term RPS compliance costs.

3. **Should the Board consider averaging costs over a period in order to more accurately reflect total compliance costs, while smoothing transient effects? How would such an average be constructed?**

Yes, the Board should average costs over a period to more accurately reflect total compliance costs over time and to smooth transient effects. We propose a five-year period as a reasonable duration to average costs across. Five years is a period that is long enough to provide clarity to the market, while also allowing the Board to pivot and make changes as necessary to assure the Cost Cap is not breached. This could be accomplished by analyzing the market every five years and publishing a five-year projection of the expected Cost Cap and the SREC and Class I REC costs and quantities required to stay below the projected Cost Cap. This method would send signals to the level of investment over a five-year period, while also allowing the Board to fulfil its promise to support the solar and other markets. The first report by the Board would include Energy Year 2019 and Energy Year 2020, consistent with S4275 awaiting the Governor's signature, that assures the two years with Cost Caps established at 9% are captured in the analysis. The analysis supporting the report would be based upon publicly available sources and should be replicable by stakeholders to provide clarity and understanding in the marketplace. This should also be developed through a stakeholder process.

4. **Should the Board adopt a true-up banking mechanism that can utilize unspent headroom from previous years as well as anticipated/projected headroom from future years?**

Yes, the Board should adopt a true-up banking mechanism that can utilize unspent headroom from previous years. A five-year true-up banking methodology would accomplish the needed market reforms.

5. **How should the accounting for such transfers be done?**

Transfer accounting can be accomplished over a five-year period, as further discussed in our response to Question 3.

MAREC appreciates the opportunity to comment on this matter. The above comments will enable the BPU to keep its renewable and greenhouse gas reduction policies moving forward <u>and</u> protect ratepayers.

Respectfully Submitted,

Bruce H. Burcat

Bruce H. Burcat, Esq.
Executive Director
Mid-Atlantic Renewable Energy Coalition
P.O. Box 385
Camden, DE 19934
302-331-4639
bburcat@marec.us

MAREC
MID-ATLANTIC RENEWABLE ENERGY COALITION

January 28, 2020
Aida Camacho-Welch
Secretary New Jersey Board of Public Utilities
Post Office Box 350
Trenton, New Jersey 08625

Re: **Comments of the Mid-Atlantic Renewable Energy Coalition on New Jersey's Class I RPS Cost Cap Calculations**

Dear Secretary Camacho-Welch:

The Mid-Atlantic Renewable Energy Coalition (MAREC) appreciates the opportunity to provide comments in relation to the Class I RPS Cost Cap calculations as requested in the Notice and Straw Proposal issued by the Board on January 6, 2019.

Introduction

MAREC is a nonprofit organization that was formed to help advance opportunities for renewable energy development primarily in the region where the Regional Transmission Organization, PJM Interconnection, operates, including New Jersey. MAREC members have developed, owned, and operated thousands of megawatts of renewable energy serving the PJM territory.

MAREC members consist of utility scale wind and solar developers, wind turbine manufacturers and non-profit organizations dedicated to the growth of renewable energy technologies. We have a strong interest in New Jersey Solar Market Transition proceedings and how Cost Cap limits could impact those goals. New Jersey makes a significant contribution to regional Class I REC requirements and supports a robust solar market. MAREC members are acutely aware of the fact that the health of any one State's market will have rippling affects across our region.

MAREC's comments provide a) a general discussion of the issues raised by the Board Staff and b) specific answers to the questions posed by BPU Staff on page 5 and 6 of the Straw Proposal.

<u>Discussion of the Issues</u>

MAREC applauds Governor Murphy and the legislature for setting ambitious goals of having New Jersey running on 100% clean energy by 2050 and 50% clean energy by 2030. To make the EMP goals a reality, the Board must now act *deliberately and wisely* on energy policy reforms, including the appropriate calculation of the RPS Cost Cap to avoid any unnecessary market uncertainty or disruptions. The decisions made at this point, at the beginning of the path to 50% and 100% clean energy, will "set the stage" for the future acceleration of the renewables market.

Careful consideration will be needed by the BPU in order to "get it right" relative to ratepayers and the State's greenhouse gases and renewable goals. There are a host of critical issues that require further deliberation including, but not limited to, setting the right incentive levels for future solar requirements; adopting a reasonable calculation of "space" under the rate caps; setting an appropriate glidepath to 100% renewables; and a host of other issues.

As discussed below, MAREC urges the Board to adopt the following methods for calculating RPS-induced costs and benefits in its Cost Cap calculations. These methods are based on grid impacts that are real and recognized in other accepted analyses. It is critical that the Board capture these impacts to comply with statutory cost caps. To do otherwise would be unfair, inaccurate and unduly discriminatory toward renewable resources.

The BPU should calculate the cost caps in a reasonable and non-discriminatory manner, inclusive of all appropriate electric customer costs and benefits associated with the Cost Cap-Eligible Programs.

The Clean Energy Act requires the BPU to keep New Jersey's renewable energy electricity costs as a percentage of total electricity costs under the specified cost caps (9% for EY 2019, 2020 and 2021; and 7% thereafter). It is imperative that the BPU use the full, net costs in determining the appropriate numerator and denominator for the Cost Cap calculation.

In calculating benefits from clean energy, (particularly renewable energy and energy efficiency), Commissions around the country (including the BPU) include such items as:

a) the "merit order effect" of renewable energy generation whereby renewable energy and load reductions reduce the market price of capacity and energy rates to all customers;
b) the savings directly provided to customers who install on-site renewable energy; and,
c) the value of volatility hedge benefits.

These benefits are created by the renewable generation used to satisfy New Jersey's RPS compliance and should be included as cost offsets in the Cost Cap numerator.

Likewise, the BPU should ensure that it complies with the mandate of the Clean Energy Act that the cost cap calculation include "total paid for electricity by all customers in the state" in the Cost Cap denominator. To satisfy the requirement of the Clean Energy Act to include <u>total</u> paid electricity, these costs should include:

a) third-party solar PPA costs;
b) direct solar PV ownership costs;
c) electricity costs of cogeneration and other on-site generation; and,
d) future electric cost surcharges such as ZREC and EE costs.

These items should be included as part of the total paid for electricity, since, if the statute had intended to require the Board to only include payments to utilities it would have so stated. The term "total paid for electricity" must be read to include payments for electricity by customers to both utilities and non-utilities.

In addition, the estimated future costs of electricity (inclusive of EDC distribution rates, transmissions charges, generation charges and other surcharges) should be based on reasonable escalation rates. In this regard, the escalators used by Cadmus in its study submitted last year are unreasonably low. The Cadmus escalation rate is well below the EIA regional forecast (2.7%) and does not recognize other anticipated New Jersey driven increases.

Direct Responses to BPU Staff Questions

B. Defining the Terms of the Clean Energy Act

1. Do parties agree that Staff has correctly identified the numerator and the denominator?

Answer:
Yes, the Numerator is correct in using the "cost to Customers of the Class 1 Renewable Energy Requirement" and the Denominator is the "Total Paid Electricity by all customers in the State" However, the numerator and denominator calculations require expansion to specify all cost and benefit factors and satisfy the definitions provided in the Clean Energy Act.

MAREC recommends that the BPU expand the Numerator to include the ratepayer benefits discussed in detail above which are induced by solar and Class I generation that reduce electric bills. Specifically, we recommend that the Numerator include the estimated compliance costs minus the ratepayer benefits provided by Class I Renewable generation.

Likewise, the Denominator should include "Total Paid for Electricity by All Customers in the State including all utility surcharges, electric supply and delivery charges and Behind the Meter (BTM) generation costs."

2. Staff notes that the State's Class I REC programs have resulted in benefits to the citizens of the State of New Jersey, including improved public health, reduction in carbon emissions, and direct financial benefits, such as lower energy and capacity costs.

    a. Is it appropriate for the Board to factor these benefits into the Cost Cap Equation?

Answer:
The Board should factor all direct financial benefits into the Cost Cap equation, as detailed below.

Based on the statutory language, we do not recommend including externalities in the Cost Cap calculations, such as the value of reductions in air emissions or employment benefits, which are included by BPU in other analyses. However, the BPU should consider these externalities in its consideration of how to address RPS Cost Cap exceedance events, should they occur.

    b. If so, please comment on which categories of benefits, if any should be included, whether they should be included in the numerator or denominator, and how they should be calculated.

Answer:

It is important that the Board include, at a minimum, all of the direct financial benefits created by solar and Class I generation. These benefits serve as explicit cost offsets in the numerator of the Cost Cap equation. The renewable energy generation, driven by Renewable Portfolio Standard (RPS) programs, provides benefits which should be subtracted from the direct costs of Class I RECs and SRECs, and should be included in the "numerator" of the rate cap calculation:

- <u>Energy/Capacity Merit Order/DRIPE</u>: Renewable energy projects are low cost resources in both the PJM energy and capacity supply stacks (for wholesale projects) or reduce PJM demand requirements (for behind the meter projects). This reduces market energy and capacity prices by displacing the highest cost resources. These Demand Reduction Induced Price Effect (DRIPE) impacts are included in the BPU minimum filing requirements for Energy Efficiency. It would be discriminatory and unreasonable not to include these benefits for Solar and Class I resources in the Cost Cap calculations, while recognizing them in Energy Efficiency.

- <u>Bill Savings from On-Site Solar</u>: Customers with on-site solar, (either third-party owned, or self-owned generation) will realize savings, which should be included as an offset to the "cost to customers" per the Clean Energy Act.

- <u>Volatility Hedge Benefits</u>: Renewable energy generation provides a hedge against energy prices, which are often priced based upon volatile fossil fuel prices. Because renewable energy has no fuel cost, it dispatches into the energy market as a price taker and displaces resources which are dependent on ever changing fossil fuel (primarily natural gas) prices. The inherent value of substituting a non-price risk energy source for a source with price risk must be captured to understand the impact on ratepayers.

3. The numerator is defined as the "cost to customers of the Class I Renewable energy requirement."

Answer:
The BPU should include all the ratepayer benefits induced by solar and Class I generation as specified in our comments above.

4. Staff's current practice in calculating clean energy program costs is to aggregate retired quantities from the annual RPS compliance reports of load serving entities and apply the last price recorded in PJM-EIS Generation Attribute Tracking System ("GATS").

a. Is there a better source of data and calculation methodology?

Answer:
The annual RPS compliance reports is the clear choice for determining the number of retired RECs/SRECs for any given energy year. However, REC prices are subject to market volatility and can vary throughout the year. It may be more appropriate to use average prices to estimate compliance costs. Monthly price data is available from a variety of sources.

b. If so, how would we measure those costs?

Answer:
There is uncertainty in any estimate but relying on a single price point could lead to inaccurate conclusions. Using monthly load-weighted average REC/SREC prices would more accurately represent the compliance costs.

c. Should the Board analyze what energy costs would have been without the Cost Cap-Eligible Programs to determine the appropriate net cost to consumers of the programs?

Answer:
Yes, the value benefits provided by Cost Cap-eligible generation should be included in the calculations as detailed above in our response in B-2.

d. If so, how should such an analysis be conducted?

Answer:
The impact on energy costs (i.e. the “merit order impact”) could be calculated using energy market models that can forecast wholesale energy prices with and without the Cost Cap-Eligible Programs. Gabel Associates has provided these calculations in the filing submitted on behalf of public entities.

e. How should Staff handle savings associated with the “merit order effect” whereby renewable energy and load reductions reduce the market price of capacity and energy rates to all customers?

Answer:

As discussed in our response to question B-2 and B-3-d above, merit order impact should be calculated and subtracted from the total cost of Cost Cap Eligible Program (the numerator).

f. How should savings received by customers who install on-site renewable energy be addressed?

Answer:
As discussed in our response to question B-2 above, savings received by customers who install on-site renewable energy should be subtracted from the total cost of Cost Cap Eligible Program (the numerator).

g. Are there volatility hedge benefits that should be included?

Answer:
Yes, as discussed in our response to question B-2 above, renewable energy generation provides a hedge against historically volatile energy prices. These benefits should be subtracted from the total cost of Cost Cap Eligible Program (the numerator).

5. The denominator of the Cost Cap Equation references “total paid for electricity by all customers in the state.”

a. Should payments associated with solar installations be included in the denominator?

Answer:
Yes, payments associated with New Jersey solar installations should be included in the denominator. PPA payments and self-ownership costs are “paid for electricity” and therefore fall under the definition of the denominator of the Cost Cap equation.

Should the Board differentiate between host-owned and third-party owned systems?

Answer:
No, there are a wide variety of system sizes, configurations and ownership structures; all of them have a “paid for electricity” component” which should be included in the calculation. An average assumption for lifetime performance of all systems is reasonable.

Ultimately, BTM solar installation displace retail purchases of electricity. On average these systems will provide some level of savings, which should be included in the numerator, and displace retail purchases, which should be included in the denominator. For example, for an average retail rate of $0.16/kWh and 25% average savings, all BTM solar generation would be valued at $0.04/kWh in the numerator and $0.12/kWh in the denominator.

b. Are there other types of customer-generated electricity whose costs should be considered? For example, should the Board include electricity costs incurred by owners of Combined Heat & Power systems, microgrids, or other large on-site generators?

Answer:
Yes, costs for electricity from CHP and other on-site generators should be included in the denominator as they are a component of “all paid for” electricity.

c. Should associated finance costs be included?

Answer:
Yes, and the methodology we have recommended implies that solar financing costs are included in the estimates for solar generation costs (in the denominator) and savings (in the numerator).

d. Should delivery charges imposed by the Electric Distribution Companies (“EDCs”) be included?

Answer:
Yes, the statutory requirements to include “all paid for electricity” requires that ALL electric costs (supply and delivery) should be included in the denominator.

e. Should Staff calculate the costs just to Board-jurisdictional load, as is the case for RPS compliance currently?

Answer:
Yes, subject to the inclusion of all electric costs discussed in this response (e.g. BTM solar costs, CHP and on-site generation electric costs, etc.). This would exclude the municipal-jurisdictional load which is also excluded from RPS compliance.

f. Should Staff calculate the costs as the sum of all EDC sales to end-use customers?

Answer:
No, as discussed above “all paid for electricity” should include all electric costs (e.g. BTM solar costs, CHP and on-site generation electric costs, etc.)

g. Should we rely on Energy Information Administration (“EIA”) sales data?

Answer:
Yes, this is an appropriate, consistent and transparent data source, with utility reported monthly detail available within 2-3 months of reporting.

h. Is there a better source of data and calculation methodology?

Answer:
We believe the EIA sales data is an appropriate data source.

i. How should the lag in EIA data be addressed?

Answer:
The lag in reported data can be addressed by adjusting prior year’s data by the current 12-month average trends.

j. Should non-bypassable surcharges, including such things as Zero Emission Credits, be included in our calculation of energy costs?

Answer:
Yes, all electric cost surcharges should be included in the denominator of total energy costs. The calculation of surcharges in forecast years must also take into account other initiatives being implemented by utilities and the Board, including costs related to energy efficiency, Zero Emission Credits, offshore wind, electric vehicles, and others. These programs include costs that will ultimately be reflected in customer rates and should be included in the denominator of the Cost Cap equation.

Conclusion

The adjustments discussed above are detailed and quantified in analysis submitted by Gabel Associates on behalf of its public clients. This analysis clearly shows that, by accounting for all appropriate costs and benefits in the Cost Cap calculations, New Jersey electric customers will remain well below the statutory cost caps through at least 2030. We believe that this approach will provide certainty and continued support to Governor Murphy’s national leadership role in championing renewable energy resources, reducing greenhouse gas emissions, and protecting ratepayers.

To do this, New Jersey must keep its “eye on the prize” and not deviate from its commitment to achieve 50% renewable energy by 2030. This principle will enable the BPU to simultaneously stay under the cost caps and meet its renewable energy goals.

MAREC appreciates the opportunity to comment on this matter.

Respectfully submitted,
Bruce H. Burcat, Esq.
Executive Director
Mid-Atlantic Renewable Energy Coalition
P.O. Box 385
Camden, DE 19934
302-331-4639
bburcat@marec.us

<u>Comments on New Jersey's Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps on Behalf of the Morris County Improvement Authority, the Somerset County Improvement Authority, and the New Jersey School Boards Association</u>

January 16, 2020

<u>Introduction</u>

The Morris County Improvement Authority (MCIA), the Somerset County Improvement Authority (SCIA), and the New Jersey School Boards Association (NJSBA) appreciate the opportunity to provide these comments in relation to the January 6, 2020 notice that contained the New Jersey Board of Public Utilities' (BPU) *Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps* (Straw Proposal).

As requested in the notice, these comments apply to Item #1 – Treatment of Cost Cap "Headroom" in the Clean Energy Act.

The SCIA and MCIA have assisted Somerset and Morris Counties to collectively install over 25 MW of solar on over 100 local units and County facilities, while the NJSBA represents New Jersey public school districts who have committed to hundreds of solar projects. Our goal is to work with the BPU to assure that the agency recognizes the significant investment made by our Counties and school districts and protects those existing commitments, as well as to work toward a transition to a new incentive program that allows for continuing opportunities to develop solar projects that can reduce public costs and help the environment -- all while protecting ratepayers.

These public sector units strive to reduce costs to benefit their residents and taxpayers, and the development of on-site solar projects are a significant part of that effort. **To promote solar market stability and protect ratepayers, Cost Cap Headroom should be averaged over a 5-year period in order to mitigate short-term cost volatility that could otherwise: a) disrupt the Governor's continuing efforts to help counties, school districts, and other public units reduce and stabilize property taxes; and b) allow for the continued, needed, and stable growth in renewable energy development.**

We have provided answers to the five specific questions set forth in the Straw Proposal which relate to the use of headroom in subsequent years (Item #1). We are also available to expand on each of these responses in more detail at the Board's convenience.

<u>Specific Comments on the Treatment of Cost Cap "Headroom" in the Clean Energy Act</u>

1. **Should the Board adopt a true-up banking methodology so that any expenditures above or below the Cost Cap in one Energy Year are carried forward to a subsequent year?**

Yes, the Board should adopt a true-up banking methodology that sends stable market signals to support a vibrant solar market and also protects ratepayers' interests.

2. **Would allowing for banking between Energy Years affect the total ratepayer impact?**

Yes, banking between Energy Years (EY) would have a positive effect on the total ratepayer impact. Because the Clean Energy Act states that the Cost Cap is based upon "total paid for electricity by all customers in the State," the rate cap will be subject to fluctuations in the market stemming from factors such as changes in energy and capacity prices, Renewable Portfolio Standard (RPS) changes in other PJM states, federal tax changes, and other similar market influences. These are not directly related to the cost of RPS compliance and add complication and uncertainty to New Jersey's efforts to meet its renewable and carbon reduction goals. Using a five-year rolling average of Cost Cap calculations would provide long-term reduction in total ratepayer costs by mitigating market volatility and reducing future RPS uncertainty. It will also help to promote a stable solar development market which is critical to achieving the benefits of New Jersey's environmental and clean energy goals. At the same time, it will enable the BPU to keep a close eye on rate impacts and meet the requirements of the Clean Energy Act.

3. **Should the Board consider averaging costs over a period in order to more accurately reflect total compliance costs, while smoothing transient effects? How would such an average be constructed?**

Yes, the Board should average costs over a 5-year period to more accurately reflect total compliance costs and to smooth transient effects. The following methodology is proposed:

The BPU would prepare successive 5-year Cost Cap reports that detail the compliance of RPS costs against the Rate Caps. The first report would be published prior to the start of EY 2021 (June 1, 2020). The second report would be published six months prior to the start of EY 2024 (June 1, 2023). All subsequent reports would be published six months prior to the fifth EY following the previous report.

The report would incorporate at least the following elements:

(1) Actual/forecasted total paid for electricity costs to customers (actual for EY 2019 and partial 2020; forecasted for the remainder of the period).
(2) Actual/forecasted net Class I RPS costs (as determined in the second scope area of this stakeholder process including direct RPS costs less RPS generated benefits).
(3) A five-year summation of item (1) and item (2).
(4) A summary of whether the summation of item (2) exceeded or did not exceed the summation of Cost Cap values associated with each EY cost from item (1).

This report will provide the market with forward looking clarity on what Class I costs can be supported under the established Cost Cap. If this report indicated that the Cost Cap is exceeded for the period, the Board could then take action to keep New Jersey under the Cost Caps.

Beginning with the second report which would be issued six months prior to EY 2024, the report would be completely prospective, meaning that items (1) and (2) would be based solely on forecasted costs.

The second report and all subsequent reports would also include a review of the previous five year period (with actual, not forecasted data) to provide the Board with clarity on whether the Cost Cap restriction was exceeded, and if it was, allow the Board to take action pursuant to the Clean Energy Act to prevent the exceedance of the cap on the cost to customers.

All BPU reports should be subject to an open stakeholder process with public access to the derivation of the analysis and reports and an opportunity to provide input before the BPU finalizes any report or action.

This analysis and reporting process will provide the BPU with an effective “Cost Compass” to make sure there is continuing focus on costs to ratepayers while allowing the market to function. It would provide the BPU, ratepayers, and the renewable marketplace with guidance in navigating future market dynamics, but is workable and also not overly complicated.

4. **Should the Board adopt a true-up banking mechanism that can utilize unspent headroom from previous years as well as anticipated/projected headroom from future years?**

Yes, the Board should adopt a true-up banking mechanism that can utilize unspent headroom from previous years. The true-up banking should be effectuated through a 5-year rolling average methodology, as described in response to question 3 above.

5. **How should the accounting for such transfers be done?**

As described in response to question 3 above, “transfers” between years should be accounted for on a 5-year basis and trued up after each successive “Cost Compass” report.

We appreciate your attention to this matter of great importance to the signatories below. Please note that we will also be providing more detailed comments on the additional items (Items #2 and #3) set forth in the Straw Proposal.

Respectfully,

The Morris County Improvement Authority
The Somerset County Improvement Authority
The New Jersey School Boards Association

Comments on New Jersey's Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps on Behalf of the Morris County Improvement Authority, the Somerset County Improvement Authority, and the New Jersey School Boards Association

January 31, 2020

Introduction and Summary

The Morris County Improvement Authority (MCIA), the Somerset County Improvement Authority (SCIA), and the New Jersey School Boards Association (NJSBA) appreciate the opportunity to provide these additional comments in relation to the Clean Energy Act, specifically addressing: (a) how the Cost Caps should be determined (BPU Issue 2) and (b) reforms to the Legacy SREC program (BPU Issue 3), as requested in the BPU's January 6, 2020 Notice and Staff Straw Proposal.

This submission provides a discussion of our position relative to these issues; and provides answers to the specific questions posed in the Staff Straw Proposal.

Somerset and Morris Counties have collectively installed over 25 MW of solar on over 100 local units and County facilities, while the NJSBA represents New Jersey public school districts who have committed to hundreds of solar projects. Our goal is to work with the BPU to assure that the BPU recognizes and protects the significant commitments made by our Counties and school districts as well as to work toward a transition to a new incentive program that allows for continuing opportunities to develop solar projects that can reduce public costs, while protecting ratepayers.

As public sector units we strive to reduce costs to benefit their residents and taxpayers, and the development of on-site solar projects are a significant part of that effort. In our recent comments, submitted on January 16, 2020, we recommended that averaging the Cost Cap Headroom over a 5-year period would mitigate short-term cost volatility and promote a stable solar market.

In order for the BPU to appropriately calculate the cost inputs of its Renewable Portfolio Standard (RPS) policies, it is imperative that the Cost Cap calculations include all relevant electric costs and RPS-induced benefits. Specifically, the numerator should include ratepayer Class I RPS costs net of all benefits provided by solar and Class I generation, while the denominator should include all electric ratepayer costs, including reasonable escalation rates and the costs of customer purchases from on-site renewable and cogeneration sources. **As shown in the attached study, if properly calculated, the rate caps will allow the BPU to stay under the cost caps <u>and</u> maintain renewable industry growth, as intended by the Clean Energy Act.**

Our recommendation on these topics is discussed in more detail below.

Issue 2: How Cost Caps Should Be Determined

The cost cap analysis should include direct customer benefits and costs that are associated with meeting the renewable energy requirements. In order to reasonably calculate rate cap impacts, the following factors should be recognized. We have commissioned Gabel Associates to perform the attached analysis to comprehensively determine cost caps and the level of head room. It provides detailed analysis based on accepted methodologies to determine the costs and benefits of meeting New Jersey's renewable energy requirements and determines whether there is sufficient "head room" for New Jersey to recognize existing commitments and move the market forward.

- The renewable resources supported by RPS programs provide the following benefits which should be subtracted from the cost of Class I RECs and SRECs, and included in the "numerator" of the rate cap calculation:

  - **Energy/Capacity Merit Order/DRIPE**: The inclusion of energy and capacity produced from Class I and Solar injects low cost resources into the PJM energy and capacity supply stack (wholesale projects) and reduces PJM demand requirements (behind the meter projects). This reduces market energy and capacity prices. These impacts are included in the BPU minimum filing requirements for Energy Efficiency. It would be discriminatory and unreasonable not to include these for Solar and Class I resources.
  - **Bill Savings from On-Site Solar**: Utility customers using solar on-site (i.e. entering into Power Purchase Agreements (PPAs) or purchasing solar) will realize savings, which should be included as an offset to the "cost to customers" per the Clean Energy Act.
  - **Volatility Hedge Benefits**: Solar projects provide a long-term hedge against volatility from electric prices sourced from fossil fuels.

- The following costs should be recognized in the "total paid for electricity by all customers" calculation and should be included in the "denominator" of the rate cap calculation:

  - **Cost of Solar to Individual Customers:** These are electricity costs to customers and should be included as a cost.
  - **Energy Efficiency Costs**: The Clean Energy Act has significant energy efficiency goals which will be funded by ratepayers and should be accounted for in the total paid for electricity by customers.

- It should be noted that the Cadmus/SEA analysis uses an unreasonably low retail rate forecast of 1.53% between 2020 and 2030. As mentioned above, because of the likely increase in costs in order to meet the requirements of the Clean Energy Act, electric rates are likely to escalate at a much higher rate than forecasted by Cadmus/SEA. The Cadmus escalation rate is well below the EIA regional forecast (2.7%) and does not recognize other anticipated New Jersey driven increases. The forecast used in the attached analysis uses accepted EIA forecasts for utility rates and includes New Jersey specific ratemaking.

Issue 3: Reforms to the Legacy SREC market

With respect to reforms to the legacy SREC program (Issue 3), we strongly request that the unique interests of public entities be recognized and that any reforms be voluntary in nature. As public entities in New Jersey who are committed to maintaining stability in property taxes and providing needed services to the public, we have a special and strong interest in assuring a fair and reliable process for the transition of the solar market. We have made substantial commitments to develop solar projects to the benefit of our residents, taxpayers, municipalities, and school districts that have developed hundreds of solar projects. **As such, we are relying on the BPU to implement a process that respects our commitments and maintains cost savings.**

Given the significant commitments of over $565 million by MCIA, SCIA, and NJSBA members which will continue to produce "legacy SRECs", we strongly encourage the BPU to: (a) manage the legacy SREC market to keep it in balance and (b) not harm the extensive commitments made by the public sector. Accordingly, within this context, we request that we be directly included in any discussions regarding legacy SREC reforms.

Answers to the Specific Questions posed by BPU Staff on the Cost Cap Calculation Methodology

B. Defining the Terms of the Clean Energy Act

1. **Do parties agree that Staff has correctly identified the numerator and the denominator?**

Yes, the statements in the Straw Proposal that define the numerator and denominator are generally acceptable. However, both the numerator and denominator calculations require clarity and expansion in order to properly incorporate all factors and satisfy the definitions provided in the Clean Energy Act.

As discussed below and quantified in the Attachment, the BPU should provide that the numerator include all ratepayer benefits that reduce electric bills induced by solar and Class I generation. Specifically, the numerator should be the "Net Cost to Customers of the Class I Renewable Energy Requirement, inclusive of the estimated compliance costs minus the ratepayer benefits provided by the Class I Renewable generation." The Class I induced benefits are detailed below in response to specific Staff questions.

Further, the denominator should include "Total Paid for Electricity by All Customers in the State including all utility surcharges, electric supply and delivery charges and estimates for Behind the Meter (BTM) generation."

2. **Staff notes that the State's Class I REC programs have resulted in benefits to the citizens of the State of New Jersey, including improved public health, reduction in carbon emissions, and direct financial benefits, such as lower energy and capacity costs.**

    a. **Is it appropriate for the Board to factor these benefits into the Cost Cap Equation?**

The Board should factor all direct financial benefits into the Cost Cap equation, as detailed below.

Based on the statutory language, we do not recommend including externalities in the Cost Cap calculations, such as the value of reductions in air emissions or employment benefits, which are included by BPU in other analyses and are very significant elements of State energy policy. However, the BPU should consider these externalities in its consideration of how to address RPS Cost Cap exceedance events, should they occur.

b. If so, please comment on which categories of benefits, if any should be included, whether they should be included in the numerator or denominator, and how they should be calculated.

It is crucial that the Board include, at a minimum, all of the direct financial benefits created by solar and Class I generation and should treat these benefits as cost offsets in the numerator of the Cost Cap equation. The renewable resources supported by RPS programs provide the following benefits which should be subtracted from the cost of Class I RECs and SRECs, and included in the "numerator" of the rate cap calculation:

- **<u>Energy/Capacity Merit Order/DRIPE</u>**: The inclusion of energy and capacity produced from Class I and Solar injects low cost resources into the PJM energy and capacity supply stack (wholesale projects) and reduces PJM demand requirements (behind the meter projects). This reduces market energy and capacity prices. These Demand Reduction Induced Price Effect (DRIPE) impacts are included in the BPU minimum filing requirements for Energy Efficiency. It would be discriminatory and unreasonable not to include these for Solar and Class I resources.

  The merit order effect is a well-known and fully documented benefit that occurs when energy with no fuel cost is injected into the power grid. Due to the way PJM (and other power markets) designate and price energy and capacity the impact is highly visible. Specifically, because PJM "stacks" energy bids to provide energy to the grid from lowest to highest costs, and clears the market at the highest accepted bid price, when energy costs with a zero or low bid price from renewable resources are bid into the market, it has the unambiguous impact of reducing the market clearing energy price.

  Accordingly, the payment for a REC is accompanied by this offsetting benefit. It would be unfair to calculate the cost of New Jersey meeting its renewable requirements to include the direct costs of a REC without including this offsetting benefit.

  Likewise, a similar effect happens in PJM's capacity market. The capacity auction "stacks" capacity offers from different resources and the presence of renewable resources supported by REC payments leads to the market clearing at a lower capacity price. Similarly, these benefits should also be included in the cost cap numerator.

  It should be noted that, with respect to capacity analysis, the recent FERC Order on PJM's capacity market has complicated these impacts. Specifically, the FERC order treats different categories of renewable resources in different ways, with varying treatments for: (a) renewables behind the meter, (b) renewables in service prior to the FERC Order, and (c) new renewables. These varying treatments are reflected in the analysis presented by Gabel Associates.

In this context, we recognize that the BPU has recently strongly objected to the FERC capacity order. It should be noted that in the event the Board's position is accepted by FERC, the capacity merit order benefits shown in the Gabel Associates analysis will increase.

Based on the above, energy and capacity merit order benefits should be reflected in the cost cap analysis utilized by the BPU.

These impacts can also be calculated using energy market simulation software. PJM provides tools and scenario analyses that can be used to estimate the impact that renewable capacity has on regional capacity prices.

- **Bill Savings from On-Site Solar**: Utility customers using solar on-site (i.e. entering into Power Purchase Agreements (PPAs) or purchasing solar for self-owned generation) will realize savings, which are benefits that should be an offset to the "cost to customers" numerator per the Clean Energy Act. Stated differently, while all customers will pay for RECs and SRECs in their utility bills, others (those who have installed on-site solar) will realize cost reductions from that generation. These are savings that should be credited to SREC costs in the numerator.

  These savings can be reasonably estimated by assuming an average savings provided by the third-party solar installations, and that a similar level of savings is realized in self-owned systems.

  For example, assuming that solar saves 25% compared to an average utility rate of \$0.16/kWh, the bill savings would equal 0.16 x 0.25 = \$0.04/kWh for all behind-the-meter solar generation.

- **Volatility Hedge Benefits**: Renewable projects provide a long-term hedge against volatility from electric prices sourced from fossil fuels. This benefit can be estimated by reviewing industry and academic studies and analyses on the subject, or by conducting volatility analysis to compare forward contracts to actual energy prices.

3. **The numerator is defined as the "cost to customers of the Class I Renewable energy requirement."**

The BPU should provide that the numerator includes the ratepayer benefits induced by solar and Class I generation. Specifically, the numerator is the "Net Cost to Customers of the Class I Renewable Energy Requirement, inclusive of the estimated compliance costs minus the ratepayer benefits provided by the Class I Renewable generation." The Class I induced benefits are detailed below in response to specific Staff questions.

4. **Staff's current practice in calculating clean energy program costs is to aggregate retired quantities from the annual RPS compliance reports of load serving entities and apply the last price recorded in PJM-EIS Generation Attribute Tracking System ("GATS").**

   a. **Is there a better source of data and calculation methodology?**

The annual RPS compliance reports is the clear choice for determining the number of retired RECs/SRECs for any given energy year. However, REC prices are subject to market volatility and can vary throughout the year. It may be more appropriate to use average prices to estimate compliance costs. Monthly price data is available from a variety of sources.

   b. **If so, how would we measure those costs?**

There is uncertainty in any estimate but relying on a single price point could lead to inaccurate conclusions. Using monthly load-weighted average REC and SREC prices would more accurately represent the compliance costs.

   c. **Should the Board analyze what energy costs would have been without the Cost Cap-Eligible Programs to determine the appropriate net cost to consumers of the programs?**

Yes, the value benefits provided by Cost Cap-eligible generation should be included in the calculations as detailed above in our response in B-2.

   d. **If so, how should such an analysis be conducted?**

As discussed in our response to question B-2 above, the impact on energy costs (i.e., the "merit order impact") should be calculated using a market dispatch simulation model that can compute past and future energy prices with and without the Cost Cap-Eligible Programs. The difference between the scenario with the Cost Cap-Eligible Programs and the scenario without the Cost Cap-Eligible Programs would represent the merit order impact on energy prices.

   e. **How should Staff handle savings associated with the "merit order effect" whereby renewable energy and load reductions reduce the market price of capacity and energy rates to all customers?**

As discussed in our response to question B-2 and B-4-d above, merit order impact should be calculated using a market dispatch simulation model and subtracted from the total cost of Cost Cap-Eligible Program (the numerator).

   f. **How should savings received by customers who install on-site renewable energy be addressed?**

As discussed in our response to question B-2 above, savings received by customers who install on-site renewable energy should be subtracted from the total cost of Cost Cap-Eligible Program (the numerator). These are benefits that are associated with SREC payments and should therefore be included in the calculation of the numerator.

g. Are there volatility hedge benefits that should be included?

Yes, as discussed in our response to question B-2 above, renewable energy generation provides a hedge against energy prices, which are often priced based upon volatile fossil fuel prices. Because renewable energy has no fuel cost, it dispatches into the energy market as a price taker and displaces resources which are dependent on ever changing fossil fuel (primarily natural gas) prices. The inherent value of substituting a non-price risk energy source for a source with fossil fuel price risk is a benefit that should be captured in the numerator to quantify the cost of compliance on ratepayers.

5. The denominator of the Cost Cap Equation references "total paid for electricity by all customers in the state."

a. Should payments associated with solar installations be included in the denominator?

Yes, payments associated with New Jersey solar installations should be included in the denominator. PPA payments and costs from owning or using energy from an onsite solar project are "paid for electricity" and therefore fall under the definition of the denominator of the Cost Cap equation. The statutory language ("total paid for electricity") is clear that all electricity costs should be included, not just utility sourced power. As a matter of law (as well as sound analysis), the Board must include the cost of electricity from utility and non-utility sources.

Should the Board differentiate between host-owned and third-party owned systems?

No, the Board should not differentiate between host-owned and third-party owned systems. While the financing of these projects differs, the lifetime outcome should be relatively similar. A simple approach to calculate these benefits would be to compare the average utility rate (as calculated for use in the denominator of the Cost Cap) against the behind-the-meter solar bill savings (as discussed above for inclusion in the numerator of the Cost Cap). The difference between the average utility rate and the behind-the-meter solar bill savings directly equates to the cost of paid for electricity of these projects (either through a third-party owned system like a PPA, or a host-owned project).

For example, assuming that solar saves 25% compared to an average utility rate of $0.16/kWh, the net costs for solar would equal 0.16 x (1 - 0.25) = $0.12/kWh for all BTM solar generation. Although this is a simplified approach, it provides a reasonable estimate with a consistent and transparent calculation.

b. Are there other types of customer-generated electricity whose costs should be considered? For example, should the Board include electricity costs incurred by owners of Combined Heat & Power systems, microgrids, or other large on-site generators?

Yes, costs for electricity from CHP and other on-site generators should be included in the denominator as they are a component of "total paid for electricity", as provided for in the Clean Energy Act.

c. Should associated finance costs be included?

Yes, and the methodology we have recommended implies that solar financing costs are included in the estimates for solar generation costs (in the denominator) and savings (in the numerator) since the cost of this energy necessarily has the cost to finance built in.

d. Should delivery charges imposed by the Electric Distribution Companies ("EDCs") be included?

Yes, all metered electric costs (supply and delivery) must be included in the denominator as they are part of "total paid for electricity" as provided for in the Clean Energy Act.

e. Should Staff calculate the costs just to Board-jurisdictional load, as is the case for RPS compliance currently?

Yes, subject to the inclusion of all electric costs discussed in this response (e.g. BTM solar costs, CHP and on-site generation electric costs, etc.). This would exclude the municipal-jurisdictional load which is also excluded from RPS compliance as customers of municipal electric utilities are not defined as "customers" under the applicable RPS law and EDECA.

f. Should Staff calculate the costs as the sum of all EDC sales to end-use customers?

No, as discussed above "all paid for electricity" should include all electric costs (e.g. BTM solar costs, CHP and on-site generation electric costs, etc.) and not be limited to EDC sales alone.

g. Should we rely on Energy Information Administration ("EIA") sales data?

Yes, this is an appropriate, consistent, and transparent data source, with utility reported monthly data available within 2-3 months of reporting, subject to more detailed adjustments as described in the Attachment.

h. Is there a better source of data and calculation methodology?

We believe the EIA sales data is an appropriate data source subject to more detailed New Jersey specific adjustments described in the Attachment

i. How should the lag in EIA data be addressed?

The 2 to 3-month lag in historical reported data can be addressed by adjusting the prior year's data by the current 12-month average trends. For example, assume that November 2019 and December 2019 are the lag months to be addressed. If the 12-month average load for September 2018 through

October 2019 is 0.5% higher than the average load for September 2017 through October 2018, November 2019 could be estimated to be 0.5% higher than November 2018 and likewise for December 2019 vs. December 2018.

j. Should non-bypassable surcharges, including such things as Zero Emission Credits, be included in our calculation of energy costs?

Yes, all electric cost surcharges, bypassable or not, should be included in the denominator of total energy costs. The calculation of surcharges must also take into account other initiatives being implemented by the Board, including costs related to energy efficiency, offshore wind, electric vehicles, and others. These programs include costs that will ultimately be reflected in customer rates and should be included in the denominator of the Cost Cap equation as part of "total paid for electricity".

Conclusion

Both fairness and sound economic principles support a cost cap calculation methodology (as described above and detailed in the Attachment to this submission) that is non-discriminatory and recognizes the full range of compliance costs and associated benefits. This will assure ratepayer protection while allowing the market to continue to develop. **As shown in the attached study, if properly calculated, the rate caps will allow the BPU to stay under the cost caps and maintain renewable industry growth, as intended by the Clean Energy Act.**

With respect to treatment of legacy SRECs, we urge the BPU to recognize that as public entities, we undertook and supported solar commitments to provide lower cost, clean energy to stabilize property taxes and to further the State's energy policy. It would be highly unfair, unreasonable, and contrary to state law and policy for the BPU to act in a manner that does not provide a stable financial climate for these public commitments; instead the BPU should respect and support the decisions made by counties, local units, and school districts for the benefit of the public. Within this context, we request that we be directly included in any discussions regarding legacy SREC reforms and that any buyouts or restructuring of legacy SRECs be voluntary in nature.

Respectfully,

The Morris County Improvement Authority
The Somerset County Improvement Authority
The New Jersey School Boards Association

Cost Cap Review and Analysis

January 31, 2020

Gabel Associates

(p) 732.296.0770 (f) 732.296.0799

www.gabelassociates.com

Purpose

- Review cost cap requirements of Clean Energy Act
- Address issues in the January 6 Staff Straw Proposal on cost cap calculations
- Present cost cap results/“head room analysis”
- Review implications

The Clean Energy Act Requirement

"The board shall ensure that <u>the cost to the customers</u> of the Class I renewable energy requirement imposed pursuant to this subsection shall not exceed nine percent of the total paid for electricity by all customers in the State for energy year 2019, energy year 2020, and energy year 2021, respectively, and shall not exceed seven percent of the <u>total paid for electricity by all customers</u> in the State in any energy year thereafter. In calculating the cost to customers of the Class I renewable energy requirement imposed pursuant to this subsection, the board shall not include the costs of the offshore wind energy certificate program"

Cost Cap Percentage Calculation

$$\frac{\boldsymbol{Cost\ to\ Customers\ of\ Meeting\ Class\ I\ and\ Solar\ Requirements}}{\boldsymbol{Total\ Paid\ for\ Electricity\ by\ All\ Customers}} \times \mathbf{100} = \%$$

Objective

- Objective is to perform analysis that captures the costs to customers to meet the Class I and Solar requirements and present Cost Cap implications.
- Based on the statutory language, we did not include externalities in the Cost Cap calculations, such as the value of reductions in air emissions and employment benefits, which are included by BPU in other analyses. However, the BPU should consider these externalities in its consideration of how to address RPS Cost Cap exceedance events, should they occur.

Analysis by Gabel Associates

- Gabel Associates has updated its analysis, which was previously submitted in October 2019 in its review of the Cadmus / SEA analysis:
  - Costs to customers should be bottom line and should capture impact on ratepayers, which includes ratepayer benefits for RPS compliance
  - Analysis used “placeholder” amounts for legacy SREC and successor solar program incentive costs to determine head room levels each year
  - Updated to include historic Energy Year 2019 data, FERC capacity order and other assumption changes
- All costs and benefits that flow through to customer rates should be fully factored into the evaluation to accurately understand cost cap implications.
- Consistent with the approach taken in energy efficiency reviews by BPU and industry practices in conducting resource analysis.
- Built bottom up cost analysis.

Benefits that Should be Recognized in the Numerator by BPU in Cost Cap Calculations

- **Numerator:** The renewable resources provide the following benefits which should be subtracted from the direct cost of Class I RECs and SRECs:
  - **Energy/Capacity Merit Order/DRIPE** – the inclusion of energy and capacity produced from Class I and Solar injects low cost resources into the PJM energy and capacity supply stack (wholesale projects) and reduces PJM demand (behind-the-meter projects). This reduces energy and capacity market prices. These merit impacts are included in the BPU minimum filing requirements for Energy Efficiency. The impact of recent FERC MOPR decision is included in this analysis.
  - **Volatility Hedge Benefits** – solar and Class I projects provide a long-term hedge against volatility from electric prices sourced from fossil fuels.
  - **Savings from PPAs** – utility customers using solar, CHP and other on-site generation will realize electric cost savings, which should be included as cost offsets in "cost to customers" per the Clean Energy Act.

Costs that Should be Recognized in the Denominator by BPU in Cost Cap Calculations

- **Denominator:** The following costs should be included in the "total paid for electricity by all customers" calculation:
  - **Cost of Solar Purchases** – The cost of PPAs or solar purchases are part of "total paid for electricity by customers" and should be included in the analysis.
  - **Cost of Cogeneration and On-Site Generation** – The electric cost of cogeneration PPAs and/or other on-site generation are part of "total paid for electricity by customers" and should be included in the analysis.
  - **Energy Efficiency Costs** – The Clean Energy Act has significant energy efficiency goals which will be funded by ratepayers and should be accounted for in the total paid for electricity by customers.
  - **Annual Cost Escalations** – BPU should adopt an escalation rate for generation, transmission and distribution from EIA for the region (2.7%) and add New Jersey specific surcharges (e.g. EE, ZEC) for a 3.8% annual escalation rate over 2020-2030 time horizon. The Cadmus analysis presents an unreasonably low escalation of 1.5% for electric costs.

Values for Incentive Costs

- The following values (price and volume) were used for Class I RECs, Legacy SRECs, Transition Solar Incentives, and Successor Solar Incentives:

Incentive	Price	Volume
Class I REC	$9 flat (per January 2020 Market)	Clean Energy Act Requirements
Legacy SREC	$180 flat through 2030	Clean Energy Act Requirements
Transition Incentive	$152 flat through 2030	400 MW a year for 2 years
Successor Incentive	$150 flat through 2030	400 MW a year after transition period

- Legacy SREC and successor incentive values are “placeholders” to determine the possible level of head room and assist in designing a program which keeps renewable development moving forward while protecting ratepayers

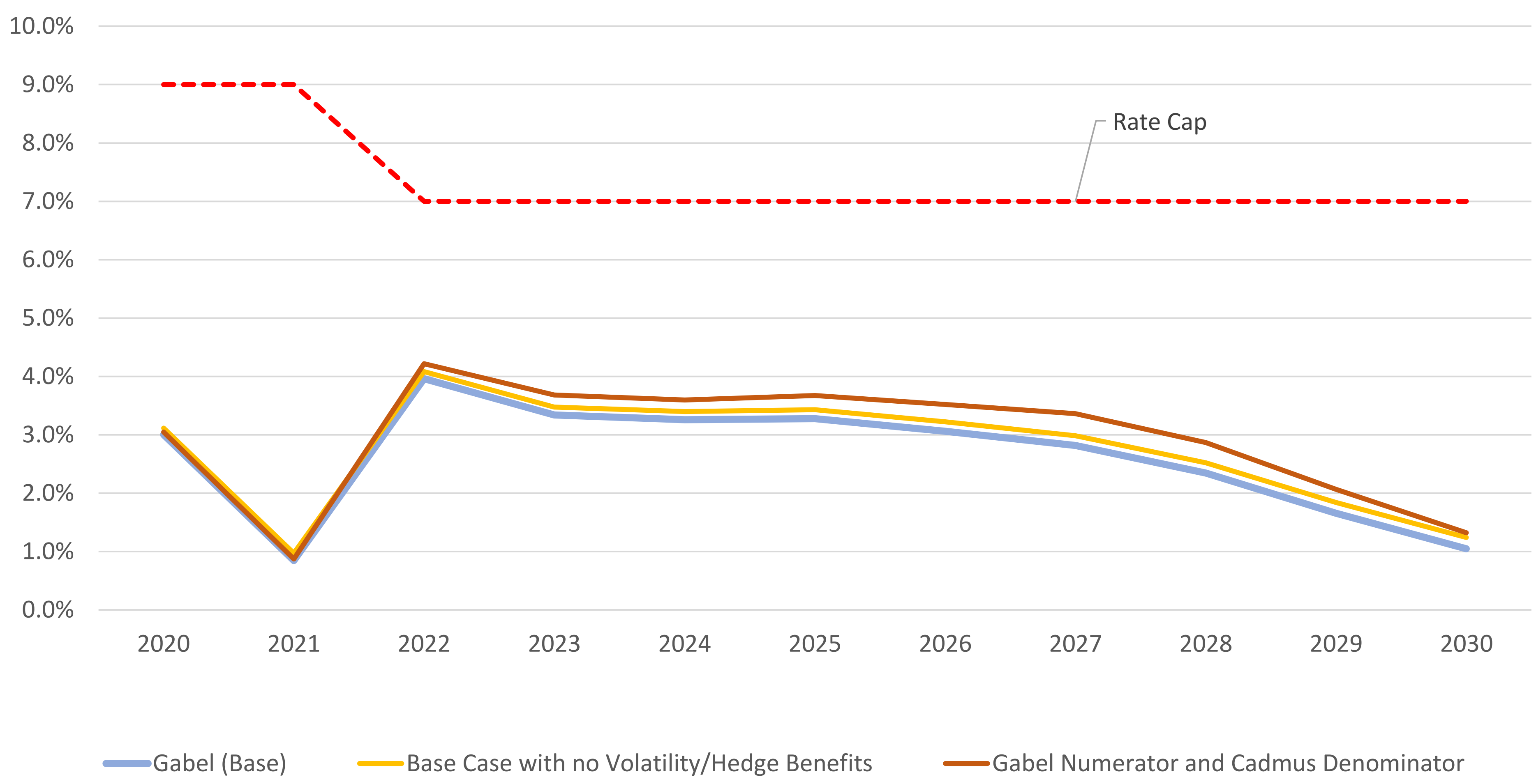
Cost Cap Analysis Results

	Category		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
[a]	Class I RECs	$mm	$95	$110	$105	$107	$138	$158	$164	$145	$152	$137	$145
[b]	SRECs	$mm	$704	$732	$732	$731	$702	$687	$643	$621	$533	$437	$315
[c]	Interim Incentive	$mm	$0	$65	$130	$130	$130	$130	$130	$130	$130	$130	$130
[d]	Successor Incentive	$mm	$0	$0	$0	$77	$153	$230	$306	$383	$460	$536	$613
[e]= ∑[a]→[d]	**Total RPS Costs**	**$mm**	**$799**	**$907**	**$966**	**$1,044**	**$1,123**	**$1,204**	**$1,243**	**$1,279**	**$1,275**	**$1,240**	**$1,203**
[f]	Solar Energy Merit Order/DRIPE	$mm	-$17	-$28	-$28	-$32	-$29	-$31	-$33	-$33	-$29	-$29	-$30
[g]	Solar Capacity Merit Order/DRIPE	$mm	-$186	-$368	-$135	-$207	-$225	-$245	-$265	-$286	-$308	-$331	-$354
[h]	Non-Solar Class I Energy Merit Order/DRIPE	$mm	-$2	-$2	-$3	-$3	-$29	-$27	-$28	-$23	-$29	-$35	-$38
[i]	Non-Solar Class I Capacity Merit Order/DRIPE	$mm	-$100	-$243	-$98	-$139	-$142	-$144	-$143	-$143	-$144	-$144	-$142
[j]	Volatility Hedge Benefits	$mm	-$13	-$16	-$16	-$18	-$20	-$22	-$25	-$27	-$30	-$32	-$35
[k]	PPA Savings from BTM Solar	$mm	-$117	-$144	-$166	-$190	-$216	-$246	-$275	-$310	-$342	-$380	-$415
[l]= ∑[f]→[l]	**Total RPS Benefits**	**$mm**	**-$436**	**-$800**	**-$446**	**-$589**	**-$661**	**-$715**	**-$770**	**-$822**	**-$882**	**-$951**	**-$1,014**
[m]= [e]+[m]	Total Net RPS Cost	$mm	$364	$107	$520	$456	$462	$489	$473	$457	$393	$289	$189
[n]	Total Paid for Electricity	$mm	$12,111	$12,645	$13,124	$13,636	$14,169	$14,913	$15,462	$16,222	$16,763	$17,491	$18,048
[o]=[o]/[p]	**Percentage**	**%**	**3.0%**	**0.8%**	**4.0%**	**3.3%**	**3.3%**	**3.3%**	**3.1%**	**2.8%**	**2.3%**	**1.7%**	**1.0%**
[p]	**Rate Cap Headroom (Exceedance)**	**$mm**	**$726**	**$1,031**	**$399**	**$499**	**$530**	**$555**	**$609**	**$678**	**$781**	**$935**	**$1,074**

Sensitivities

- Reviewed multiple sensitivities, including:
  - Base Case (as summarized throughout this document)
  - Base Case without Volatility/Hedge benefits
  - Gabel Numerator and Cadmus Denominator

Sensitivity Results



Takeaways

- There is adequate headroom under the cost caps throughout the study period under all scenarios
- Cadmus / SEA approach is inconsistent with Murphy energy policy and BPU approach in other matters
- Renewable rate benefits should be recognized; electricity payments should be reasonably forecasted
- In the Base Case, there is $399M of headroom in 2022
- **BPU can maintain renewable industry growth <u>and</u> show annual savings below the cost cap under a variety of scenarios**

Appendix:
Key Assumptions

- Total Cost Basis sourced from 2019 EIA Form 861, escalated by 2019 EIA Annual Energy Outlook
- Class I REC, SREC, Class II REC, and OREC requirements sourced from the Clean Energy Act (P.L. 2018 c.17)
- OREC rate based upon BPU approved OREC cost schedule
- Energy and Capacity net-back value based upon BPU OSW Guidance Document Attachment 7: price inputs
- Class I REC costs set to $9 for the entire period consistent with January 2020 market prices
- Class II REC forecast based upon NJ RPS Compliance Report, escalated by 2% per year
- TRECs set to $180/MWh and SREC Successor program set to $150/MWh
- Electric Energy Merit Order/DRIPE calculated using AURORAxmp software platform
- Electric Capacity Merit Order/DRIPE derived from PJM scenario analysis for available delivery years, escalated by capacity market clearing price provided in BPU OSW Guidance Document Attachment 7: price inputs
- Volatility Hedge Benefit assumed to be 10% of market energy and capacity value based upon industry survey, calculated from energy and capacity values provided in BPU OSW Guidance Document Attachment 7: price inputs
- Avoided bill costs from solar assumes 25% savings from PPA against retail rate
- CHP electric generation based on 312 MW of distributed generation cogeneration capacity
- Incremental EE costs are derived based upon OCE FY2020 energy efficiency filing

MSSIA MID-ATLANTIC SOLAR & STORAGE INDUSTRIES ASSOCIATION
Mid-Atlantic Solar & Storage Industries Association
Rutgers Eco-Complex, Suite 208-8
1200 Florence-Columbus Road, Bordentown, NJ 08505 | info@mseia.net

January 16, 2020

Ms. Aida Camacho-Welch
Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue
9th Floor
Trenton, NJ 08625

Via email to:
Charles Gurkas Charles.Gurkas@bpu.nj.gov

Re: Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps

Dear Ms. Camacho-Welch:

The Mid-Atlantic Solar & Storage Industries Association (MSSIA) is pleased to present these comments in regard to the above-referenced notice.

MSSIA is a trade organization that has represented solar energy companies in New Jersey, Pennsylvania, and Delaware since 1997. During that 22-year period, the organization has spearheaded efforts in the Mid-Atlantic region to make solar energy a major contributor to the region's energy future. Its fundamental policy goals are to: (1) grow solar energy and storage in our states as quickly as practicable; (2) do so at the lowest possible cost to ratepayers, while delivering the greatest possible benefit as a public good; and (3) preserve diversity in the market, including opportunity for Jersey companies to grow and create local jobs (https://mseia.net/fundamental-principles/).

In this response to the above-referenced notice, MSSIA responds to staff's questions under Option A, Treatment of Cost Cap "Headroom" in the Clean Energy Act. MSSIA will respond later to the other two options presented in the notice. MSSIA's responses are shown below in blue font after the staff questions.

1. Should the Board adopt a true-up banking methodology so that any expenditures above or below the Cost Cap in one Energy Year are carried forward to a subsequent year?

Yes, MSSIA believes that the Board should adopt such a true-up mechanism. It will give the Board the maximum amount of flexibility in determining how to meet the requirements of the Clean Energy Act, the Energy Master Plan (EMP), and the Integrated Energy Plan (IEP).

2. Would allowing for banking between Energy Years affect the total ratepayer impact?

Because allowing for banking the headroom under the cap, and using it in another year, would allow the Board to drive the construction of more solar in the year the headroom is used, the practice could affect total ratepayer impact in that year.

When considered in the context of meeting the Clean Energy Act, EMP, and IEP requirements and recommendations, the application of banking may just be reshuffling the *timing* for construction of a given amount of total solar energy.

There would be some savings associated with using the headroom within the next four years, since it would enable the construction of more solar while the federal investment tax credit (FITC) is still available to offset state incentives - and correspondingly less after the FITC is gone. It is possible, therefore, that the practice of using headroom in other years could be close to being rate-impact neutral.

3. Should the Board consider averaging costs over a period in order to more accurately reflect total compliance costs, while smoothing transient effects? How would such an average be constructed?

MSSIA believes that averaging could be another valuable policy tool. The average could be expressed as the average of the *calculated fractions of the allowable maximum cost* in each year of several years in the immediate past. If desired, the average could also include the predicted fraction for years in the immediate future.

For instance, if in a year with a cost cap of 9% the total renewable costs reach 7.5%, the fraction of allowable cost would be 7.5/9.0 = 0.833.

If in a subsequent year cost cap is 7% and the total costs again reach 7.5%, the fraction would be 7.5/7.0 = 1.071.

These fractions could then be averaged. The averaging could be either unweighted, or weighted by the total cost (denominator) for each year.

4. Should the Board adopt a true-up banking mechanism that can utilize un-spent headroom from previous years as well as anticipated/projected headroom from future years?

Even though MSSIA believes staff's estimate, as expressed in the notice, that banking headroom in the early years will be enough to cover the subsequent deficits in the "kink" years, the ability to "borrow" from a future year could be useful if the estimate eventually falls short of reality.

5. How should the accounting for such transfers be done?

MSSIA believes that once the methodology for calculating the numerator and the denominator of the cost cap calculation is settled, that calculation should be performed as soon as possible after the end of each year. Then the result should be compared with the requirement for that year, yielding a difference. That difference would then be multiplied by the denominator to produce a dollar value for headroom for each year. Those dollar values for each year could then be accumulated year upon year, enabling the practices discussed above to be performed.

MSSIA thanks staff for the opportunity to provide input on this matter.

Sincerely,

Lyle K. Rawlings, P.E.
President

MSSIA
MID-ATLANTIC SOLAR & STORAGE INDUSTRIES ASSOCIATION
Mid-Atlantic Solar & Storage Industries Association
Rutgers Eco-Complex, Suite 208-8
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January 16, 2020

Ms. Aida Camacho-Welch
Secretary
New Jersey Board of Public Utilities
44 South Clinton Avenue
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Trenton, NJ 08625

Via email to:
Charles Gurkas Charles.Gurkas@bpu.nj.gov

Re: Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps Parts B, C, and D

Dear Ms. Camacho-Welch:

The Mid-Atlantic Solar & Storage Industries Association (MSSIA) is pleased to present these comments in regard to the above-referenced notice.

MSSIA is a trade organization that has represented solar energy companies in New Jersey, Pennsylvania, and Delaware since 1997. During that 23-year period, the organization has spearheaded efforts in the Mid-Atlantic region to make solar energy a major contributor to the region's energy future. Its fundamental policy goals are to: (1) grow solar energy and storage in our states as quickly as practicable; (2) do so at the lowest possible cost to ratepayers, while delivering the greatest possible benefit as a public good; and (3) preserve diversity in the market, including opportunity for Jersey companies to grow and create local jobs (https://mseia.net/fundamental-principles/).

In this response to the above-referenced notice, MSSIA responds to staff's questions under B. Defining the Terms of the Clean Energy Act, C. Reform of the Legacy SREC Program, and D. Other Options.

MSSIA's responses are shown below in blue font after the staff questions.

Option B. Defining the Terms of the Clean Energy Act

In regards to calculating the Cost Cap, Staff requests responses to the following questions:

1. Do parties agree that Staff has correctly identified the numerator and the denominator?

Yes, MSSIA agrees that Staff has correctly identified the numerator and denominator.

2. Staff notes that the State's Class I REC programs have resulted in benefits to the citizens of the State of New Jersey, including improved public health, reduction in carbon emissions, and direct financial benefits, such as lower energy and capacity costs.

a. Is it appropriate for the Board to factor these benefits into the Cost Cap Equation?

Yes, MSSIA believes that the cost of renewable energy programs as applied to the cost caps should be the net cost to customers. Therefore, benefits accruing to those customers should be included in the calculation.

b. If so, please comment on which categories of benefits, if any should be included, whether they should be included in the numerator or denominator, and how they should be calculated.

MSSIA believes that the benefits that should be included encompass effects on the cost of power on the wholesale grid, effects on the social cost of pollution, particularly global warming pollutants; and effects on the state economy.

In November 2012, MSSIA (then MSEIA) published a study it commissioned Clean Power Research to conduct, entitled *"The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania"*. Clean Power Research is one of the world's most respected consulting firms in this field of study, and has done work of this type for many jurisdictions in the U.S., including studies done for the purpose of rate-making. In calculating benefits to the grid, the study incorporated large amounts of LMP data from PJM at seven representative nodes on the PJM system. The study is attached to these comments.

MSSIA recommends that the following benefits, as excerpted from the study, be included in the cost cap calculation:

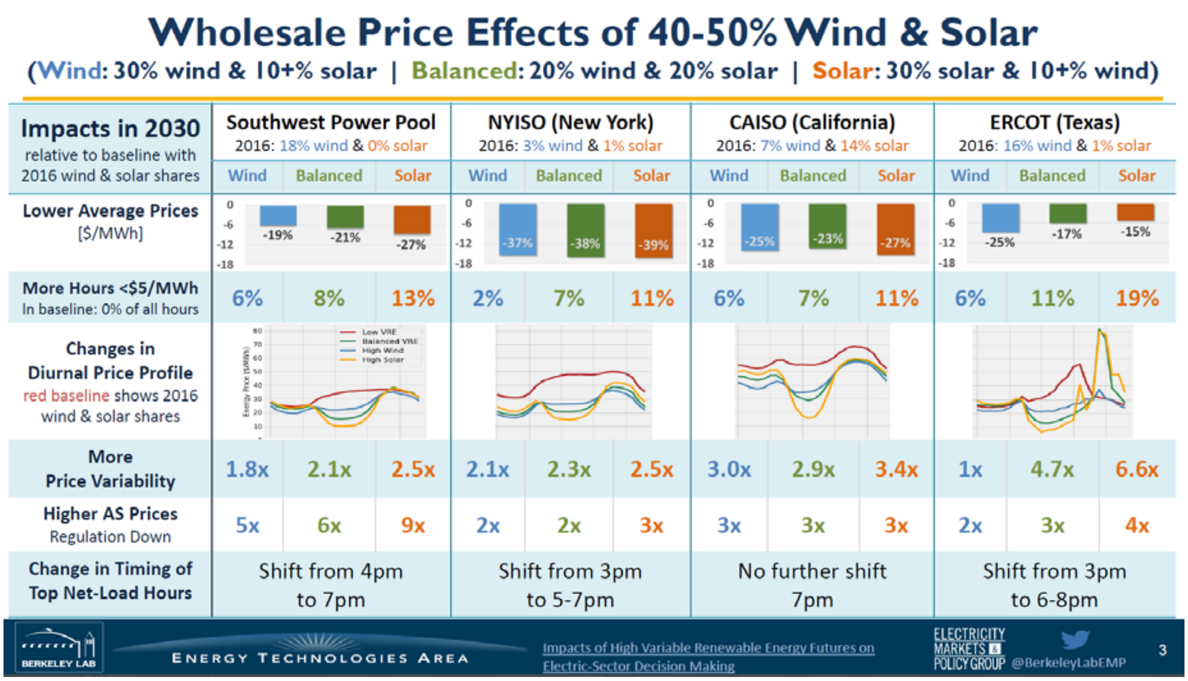
Value Component	Basis
Fuel Cost Savings	Cost of natural gas fuel that would have to be purchased for a gas turbine (CCGT) plant operating on the margin to meet electric loads and T&D losses.
O&M Cost Savings	Operations and maintenance costs for the CCGT plant.
Security Enhancement Value	Avoided economic impacts of outages associated due to grid reliability of distributed generation.
Long Term Societal Value	Potential value (defined by all other components) if the life of PV is 40 years instead of the assumed 30 years.
Fuel Price Hedge Value	Cost to eliminate natural gas fuel price uncertainty.
Generation Capacity Value	Cost to build CCGT generation capacity.
T&D Capacity Value	Financial savings resulting from deferring T&D capacity additions.
Market Price Reduction	Wholesale market costs incurred by all ratepayers associated with a shift in demand.
Environmental Value	Future cost of mitigating environmental impacts of coal, natural gas, nuclear, and other generation.
Economic Development Value	Enhanced tax revenues associated with net job creation for solar versus conventional power generation.
(Solar Penetration Cost)	Additional cost incurred to accept variable solar generation onto the grid.

Note that the last item on the list above, "Solar Penetration Cost", is a cost burden or negative benefit. At current levels of solar penetration, these infrastructure development costs are small, and are largely paid for by solar developers, so generally their cost is already embedded in the incentive payments.

In addition, MSSIA recommends that the value of external investment in the state, in particular the infusion of federal funds associated with the federal investment tax credit and other tax incentives, jobs in associated industries and professions, and indirect and induced employment be included as benefits.

Finally, MSSIA recommends that the downward pressure on fossil fuel prices be included in the calculation. The link between supply and demand in fossil fuel markets is well established. Some examples include recent winters in which severe cold snaps brought on sharp, rapid increases in wholesale natural gas prices, which then quickly reversed when temperatures returned to normal (increased demand leading to higher prices); and the long-term decrease in natural gas prices attributed to fracked gas production from the Marcellus Shale formation (increased supply leading to lower prices). By the same principle, the progressive displacement of fossil fuels from the state and regional power generation pool will lower the demand for those fuels (decreased demand leading to lower prices).

Regarding the effects of solar energy on the cost of power on the wholesale grid, this topic was also studied by USDOE's Lawrence Berkeley National Laboratory in a study entitled, *"Impacts of High Variable Renewable Energy Futures on Electric Sector Decision Making".* One of the Regional Transmission Organizations (RTO's) that was studied was NYISO (New York). As shown in the chart below, the study found that a NYISO future in which solar is 30% and wind is 10+% of electric sales by 2030, **wholesale prices would be lowered by 39% relative to 2016**.



3. The numerator is defined as the "cost to customers of the Class I Renewable energy requirement."

4. Staff's current practice in calculating clean energy program costs is to aggregate retired quantities from the annual RPS compliance reports of load serving entities and apply the last price recorded in PJM-EIS Generation Attribute Tracking System ("GATS").

   a. Is there a better source of data and calculation methodology?

MSSIA believes that the weighted average price recorded by GATS for a given year would be better than the last price recorded.

b. If so, how would we measure those costs?

See above.

c. Should the Board analyze what energy costs would have been without the Cost Cap-Eligible Programs to determine the appropriate net cost to consumers of the programs?

Yes.

d. If so, how should such an analysis be conducted?

MSSIA believes that the methodologies employed by Clean Power Research in the MSSIA study referred to in 2.b., above, or similar methodologies of equal rigor, should be used in the analysis. Alternatively, if required by constraints on time and funding, results from studies such as the Clean Power Research study and the Lawrence Berkeley Laboratory could be used in a meta-analysis to estimate the difference in costs engendered by the programs.

e. How should Staff handle savings associated with the “merit order effect” whereby renewable energy and load reductions reduce the market price of capacity and energy rates to all customers?

See MSSIA’s answer to 4.d., above. Both the studies that were mentioned there analyzed the effect of renewables on wholesale prices due to the merit order effect.

f. How should savings received by customers who install on-site renewable energy be addressed?

Since those savings constitute a reduction in the total cost to customers of the Class I Renewable Energy Requirement, they should be included in the calculation of the numerator.

g. Are there volatility hedge benefits that should be included?

Yes, especially fuel price hedge benefits, as discussed above in MSSIA’s answers to 2.d.

5. The denominator of the Cost Cap Equation references “total paid for electricity by all customers in the state.”

a. Should payments associated with solar installations be included in the denominator? Should the Board differentiate between host-owned and third-party owned systems?

Yes. Customer payments for solar installations are part of the “Total Paid for Electricity by All Customers in the State.” Both direct payments for energy to third-party owners of systems, and customer payments for systems they own directly. In both cases those payments are payments for electricity, so they should be included in the total.

In the case of third-party owned equipment, the BPU has records of PPA prices and terms, along with system sizes and performance estimates, in the NJCEP SRP application records. A statistical sampling of that data, by year and by market sector, could be used to estimate the total payments. For the customer-owned equipment, it would be necessary to calculate a levelized cost of energy (LCOE), including cost of financing, to estimate equivalent customer payments by year.

b. Are there other types of customer-generated electricity whose costs should be considered? For example, should the Board include electricity costs incurred by owners of Combined Heat & Power systems, microgrids, or other large on-site generators?

Yes. Payments associated with other types of customer-generated electricity are also part of the total customers pay for electricity, whether customer-owned or third-party owned.

c. Should associated finance costs be included?

Yes (see discussion of LCOE in 5.b., above).

d. Should delivery charges imposed by the Electric Distribution Companies ("EDCs") be included?

Yes, they are part of the total paid for electricity by customers too.

e. Should Staff calculate the costs just to Board-jurisdictional load, as is the case for RPS compliance currently?

No. The definition of the denominator refers to "all customers in the state", so that would include load incurred by non-jurisdictional customers, too.

f. Should Staff calculate the costs as the sum of all EDC sales to end-use customers?

Not unless the added payments referred to in questions 5.a through 5.e and 5.j. are included as well.

Note: MSSIA assumes that the duplication of the numbering of sub-questions 5.a. through 5.d was unintentional, and has renumbered the following four sub-questions accordingly.

g. Should we rely on Energy Information Administration ("EIA") sales data?

MSSIA does not believe that EIA data is the most accurate or up-to-date source.

h. Is there a better source of data and calculation methodology?

MSSIA believes that the sum of EDC sales are the best source, with the additions noted in 5.a. through 5.e., and 5.j.

i. How should the lag in EIA data be addressed?

See MSSIA answers to 5.g. and 5.h. above.

j. Should non-bypassable surcharges, including such things as Zero Emission Credits, be included in our calculation of energy costs?

Yes, since they are part of the total paid by customers, they should be included.

C. Reform of the Legacy SREC Program

1. Should Staff consider reforms to the SREC market in order to reduce the variability in potential SREC outcomes?

Yes.

2. Should owners of SREC contracts be required to take part in any restructuring of the program, or should participation be voluntary?

Yes, participation should be voluntary. MSSIA believes that an involuntary requirement for legacy projects to take part in a restructured program could create a number of problems, including the following:

i. Many projects have their SREC generation pledged in forward contracts. Forcing a large number of parties to break contracts would be problematic.

ii. Some projects that are already critically impaired could be hard-pressed to accept reductions, even in a trade-off for greater security. This may include some public-sector projects (schools, local government, local authorities, and the like), in which further impairment would directly and adversely affect the public within their jurisdictions.

iii. A forced move to a different program than investors were given to expect when they invested could hurt the state's long-term credibility as a trusted investment partner, and its ability to attract investment in the future. The effect could include sectors unrelated to renewable energy. Banks and similar financial institutions, equity investors, tax equity investors, institutional investors, and more would be effected.

MSSIA believes that it is possible to offer a voluntary program that will attract substantial participation, and still achieve a large savings in legacy program cost. MSSIA's analysis demonstrating this is discussed below.

MSSIA recommends that if the project owners' decisions to participle in any such alternative program is voluntary, projects that have their SRECs committed in forward contracts should be able to enroll to participate in the new program as soon as their contractual obligations have expired.

3. Should Staff examine moving toward converting SRECs to a fixed price product, or would it be better to look at a lower Alternative Compliance Payment ("ACP") and the institution of a floor price or buyer of last resort?

MSSIA believes that a fixed-price SREC payment, as has already been offered in the TREC program, would be simpler, faster to implement, more efficient in lowering costs, and more *certain* to lower costs, compared to a lower SACP with a floor price or buyer of last resort.

4. If Staff were to recommend setting a fixed price for SRECs, how should that price be set?

If a fixed-price SREC is chosen, the price should be set administratively using economic modeling that follows financial sector norms, and includes true collaboration with solar industry experts and investors. The price needs to be set in such a way that it provides a viable alternative to staying in the current market. If that is the case the program can remain voluntary, as discussed above, while still attracting robust participation and offering large-scale savings to ratepayers.

An important factor in setting such a price is the difference between vintage years. MSSIA studied a small sample of projects from various vintage years, using actual contractual data from those projects. In this admittedly limited study, MSSIA found that the sampled projects from 2012 and earlier are seriously impaired, with very low IRR's projected through the ends of their qualification lives. Projects from 2013 and after fared better.

MSSIA has proposed legacy cost reduction programs for many years, including a detailed proposal in its recent 2019 motion. At this point MSSIA is analyzing three alternative cost-reducing program designs. The three alternatives have been informed by MSSIA's past work and research; experience with programs from other states; and concepts contributed by non-MSSIA solar industry entities, BPU staff, and NGO stakeholders. MSSIA has been analyzing these three alternatives on an apples-to-apples basis in order to assess and compare their ability to achieve savings. The measures of success in MSSIA's analysis are:

i. Total potential net present value savings to ratepayers through the completion of payments for each program alternative.
ii. Total net present value savings to ratepayers though the end of the "kink year" period (through the end of 2024) for each program alternative.

In all three cases, the savings as presented below are the theoretical maximum – that is, they assume 100% participation. Naturally, the lower the participation in the program, the lower the savings will be. MSSIA's model can incorporate year-by-year participation rates as a % of total capacity in each year.

Alternative 1 is a simple fixed, levelized SREC, with the price set by the board in a board order. In this respect the alternative would function in a way very similar to the TREC program. The SREC qualification life for each project would be its current remaining qualification life. A single SREC price for all vintage years was assumed, and set to $150.

Alternative 2 begins like Alternative 1. It also has a fixed, levelized SREC price set by board order, also at $150 for all vintage years, for the remainder of the current qualification life. But in this alternative, a special purpose entity is formed to issue bonds, in order to stretch out the cost of payments to the projects over 20 years (like using a mortgage to pay for a house over a long period of time). The special purpose entity would be entirely private, although working under the provisions of a board order. The bonds would not be state-backed bonds; they would be private as well.

Alternative 3 also begins like Alternative 1, and in fact is identical in almost all respects. The only differences are that it would set a lower SREC price ($120), but lengthen each project's qualification life by 5 years.

For alternative 3, the idea is to retain the simplicity and speed of implementation of Alternative 1, but achieve greater savings during the period through the "kink years".

Alternative 3 also is designed to differentiate among vintage years to some extent. It provides a somewhat greater degree of assistance to the older vintage years that need more, while still attracting participation from more recent projects.

The results of MSSIA's analysis and comparison of these three alternatives are preliminary. MSSIA needs to perform further checking, refinement, and peer review before publishing details and final results. Table 1, below, presents the preliminary results. As stated before, it should be noted that the results as presented are the theoretical maximum, based on 100% participation. Actual participation rates are likely to be lower, particularly during the first few years, when many projects will still have their SREC generation under contract.

Table 1. NPV Cost Savings for Legacy Cost Reduction Alternatives (Preliminary)

LEGACY COST REDUCTION ALTERNATIVES NPV COST SAVINGS ($millions)[1]		
ALTERNATIVE	**THROUGH 2024**	**THROUGH END OF PAYMENTS**
ALTERNATIVE 1 - FIXED SREC	**664**	**732**
ALTERNATIVE 2 - FIXED SREC WITH BOND	**2,363**	**1,651**
ALTERNATIVE 3 - FIXED SREC WITH 5 YRS. ADDED LIFE	**1,065**	**967**

Notes to table:

1. Assumes 100% participation
2. Assumes that in the business-as-usual case SREC market is stable and balanced.
3. Assumes proposed program can go into effect by 2021

Comparing the alternatives based on the NPV cost savings to ratepayers, it can be seen that Alternative 2 offers far more savings, both during the period through 2024 (the "kink years") and during the period from the start of the program through the end of all payments.

Alternatives 1 and 3, on the other hand, have the advantage of being much simpler and faster to design and implement.

The relative net present value (NPV) savings are sensitive to the choice of discount rate. A 7% discount rate was used in this analysis. That is the rate MSSIA has seen used by state agencies in assessing and comparing rate impacts, and it is the rate most often used in federal matters. However, federal OMB and executive branch guidance on discount rates may provide justification for lower discount rates in some cases, including cost-benefit analyses involving multi-generational issues. If a lower discount rate is used, the cost savings advantage enjoyed by Alternative 2 would be reduced.

5. If Staff were to look at a lower ACP and buyer of last resort program, how should such a program be structured?

MSSIA does not recommend this path, but if it is chosen, then first it would be advisable to design the simplest possible way to implement the buyer of last resort option. The simplest design might be to mimic the fixed SREC approach discussed above. If the Board establishes a price and orders the EDC's to pay that as a buyer of last resort, the design could be workable. The question would be, though, if the floor price is enough to provide an acceptable return for projects, why pay *anything* higher than the floor price? The transaction costs and administrative costs associated with maintaining a trading market, along with the continued (although reduced) risk premium, would suggest that the lower ACP/buyer of last resort path is not the most cost-efficient choice.

A big problem with the buyer of last resort option – the way it was defined during the transition program stakeholder process – is that the floor price could not be accessed by a project until the end of the SRECs' trading life. That means that in order for owners to avail themselves of the floor price, they would have to defer the SREC revenue from the project for 5 years (the current SREC trading life). Many if not most project owners would not have the financial resources to be able defer revenue for that long. Many would not be able to pay the debt associated with the project.

Furthermore, a dollar paid 5 years in the future is worth less than a dollar paid today, because of the time value of money. For an investor who invested for an 8.5% rate of return (a typical hurdle rate for investors), a dollar paid 5 years in the future is worth 33.5% less than a dollar paid today ($1 – 1/1.085^5$).

Combining the two problems discussed above, it is clear that owners would be forced to sell at market prices far below the floor. Then, of course, the market would respond with a spot price much lower than the floor. A program design working that way would clearly be unworkable. If a buyer of last resort design is adopted (which MSSIA does not recommend for all the reasons discussed above), the buyer of last resort option would have to be exercisable in the first year in which an SREC is generated.

6. Should the Board consider a "tight collar"? How would such a program be implemented?

MSSIA assumes that a "tight collar" means a lower SACP coupled with a simple floor price or coupled with a buyer-of-last-resort floor price, in which the floor price and ACP are very close together. The same questions discussed in MSSIA answer to question 5 above apply: if the floor price is adequate, why pay anything more than that? And why pay the transaction costs and administrative costs associated with maintaining a market that serves no purpose?

If the "tight collar" is chosen despite these issues, then MSSIA believes that a simple floor price by board order, in which RFP obligees are required to pay a minimum price, seems to be the simplest and most effective way to do it.

7. Are there other reforms that Staff should consider?

Not at this time.

D. Other Options

MSSIA is not considering other options related to the cost caps at this time.

MSSIA thanks staff for the opportunity to provide input on this matter.

Sincerely,

Lyle K. Rawlings, P.E.
President

The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania

Richard Perez

Benjamin L. Norris

Thomas E. Hoff

November 2012

Prepared for:

Mid-Atlantic Solar Energy Industries Association

&

Pennsylvania Solar Energy Industries Association

Prepared by:

Clean Power Research

1700 Soscol Ave., Suite 22

Napa, CA 94559

Clean Power Research

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Executive Summary

This report presents an analysis of value provided by grid-connected, distributed PV in Pennsylvania and New Jersey. The analysis does not provide policy recommendations except to suggest that each benefit must be understood from the perspective of the beneficiary (utility, ratepayer, or taxpayer).

The study quantified ten value components and one cost component, summarized in Table ES- 1. These components represent the benefits (and costs) that accrue to the utilities, ratepayers, and taxpayers in accepting solar onto the grid. The methodologies for quantifying these values are described further in Appendix 2.

Table ES- 1. Value component definitions.

Value Component	Basis
Fuel Cost Savings	Cost of natural gas fuel that would have to be purchased for a gas turbine (CCGT) plant operating on the margin to meet electric loads and T&D losses.
O&M Cost Savings	Operations and maintenance costs for the CCGT plant.
Security Enhancement Value	Avoided economic impacts of outages associated due to grid reliability of distributed generation.
Long Term Societal Value	Potential value (defined by all other components) if the life of PV is 40 years instead of the assumed 30 years.
Fuel Price Hedge Value	Cost to eliminate natural gas fuel price uncertainty.
Generation Capacity Value	Cost to build CCGT generation capacity.
T&D Capacity Value	Financial savings resulting from deferring T&D capacity additions.
Market Price Reduction	Wholesale market costs incurred by all ratepayers associated with a shift in demand.
Environmental Value	Future cost of mitigating environmental impacts of coal, natural gas, nuclear, and other generation.
Economic Development Value	Enhanced tax revenues associated with net job creation for solar versus conventional power generation.
(Solar Penetration Cost)	Additional cost incurred to accept variable solar generation onto the grid.

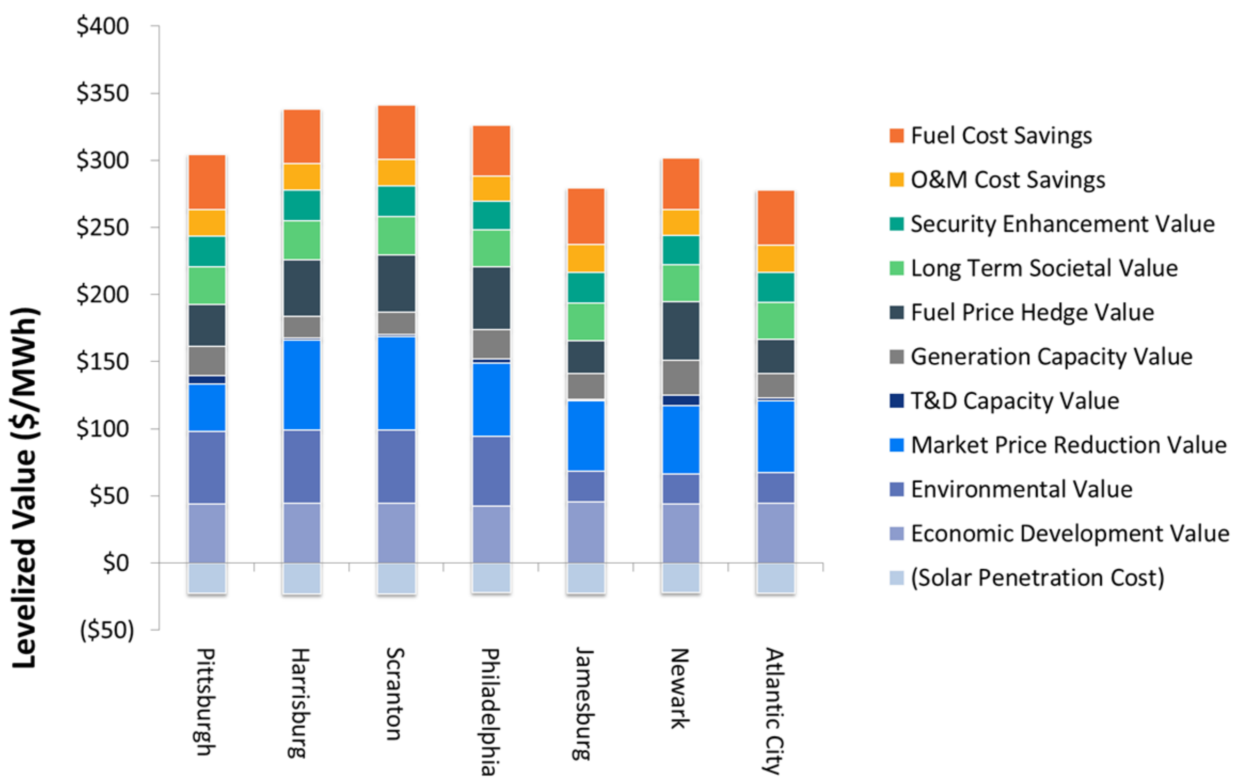
The analysis represents the value of PV for a "fleet" of PV systems (that is, a large set of systems generating into the grid). Four different fleet configurations (e.g., fixed, south-facing, 30-degree tilt angle) were evaluated at each of seven locations (Pittsburgh, PA; Harrisburg, PA; Scranton, PA;

Philadelphia, PA; Jamesburg, NJ; Newark, NJ; and Atlantic City, NJ). These locations represent a diversity of geographic and economic assumptions across six utility service territories (Duquesne Light Co., PPL Utilities Corp, PECO Utilities Corp, Jersey Central P&L, PSE&G, and Atlantic Electric).

The analysis represented a moderate assumption of penetration: PV was to provide 15% of peak electric load for each study location (higher penetration levels result in lower value per MWh). PV was modeled using SolarAnywhere®, a solar resource data set that provides time- and location-correlated PV output with loads. Load data and market pricing was taken from PJM for the six zones, and utility economic inputs were derived from FERC submittals. Additional input data was taken from the EIA and the Bureau of Labor Statistics (producer price indices).

Levelized value results for the seven locations are shown in Figure ES- 1 and Table ES- 2. Detailed results for all scenarios are included in Appendix 3.

Figure ES- 1. Levelized value ($/MWh), by location (South-30).



The following observations and conclusions may be made:

- **Total Value**. The total value ranges from $256 per MWh to $318 per MWh. Of this, the highest value components are the Market Price Reduction (averaging $55 per MWh) and the Economic Development Value (averaging $44 per MWh).
- **Market Price Reduction**. The two locations of highest total value (Harrisburg and Scranton) are noted for their high Market Price Reduction value. This may be the result of a good match between LMP and PV output. By reducing demand during the high priced hours, a cost savings is realized by all consumers. Further investigation of the methods may be warranted in light of two arguments put forth by Felder [32]: that the methodology does address induced increase in demand due to price reductions, and that it only addresses short-run effects (ignoring the impact on capacity markets).
- **Environmental Value**. The state energy mix is a differentiator of environmental value. Pennsylvania (with a large component of coal-fired generation in its mix) leads to higher environmental value in locations in that state relative to New Jersey.
- **T&D Capacity Value**. T&D capacity value is low for all scenarios, with the average value of only $3 per MWh. This may be explained by the conservative method taken for calculating the effective T&D capacity.
- **Fuel Price Hedge**. The cost of eliminating future fuel purchases—through the use of financial hedging instruments—is directly related to the utility's cost of capital. This may be seen by comparing the hedge value in Jamesburg and Atlantic City. At a utility discount rate of 5.68%, Jersey Central Power & Light (the utility serving Jamesburg) has the lowest calculated cost of capital among the six utilities included in the study. In contrast, PSE&G (the utility serving Newark) has a calculated discount rate of 8.46%, the highest among the utilities. This is reflected in the relative hedge values of $24 per MWh for Jamesburg and $44 per MWh for Newark, nearly twice the value.
- **Generation Capacity Value**. There is a moderate match between PV output and utility system load. The effective capacity ranges from 28% to 45% of rated output, and this is in line with the assigned PJM value of 38% for solar resources.

Table ES- 2. Levelized Value of Solar ($/MWh), by Location.

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Energy							
Fuel Cost Savings	$41	$41	$41	$38	$42	$39	$41
O&M Cost Savings	$20	$20	$20	$18	$21	$19	$20
Total Energy Value	$61	$60	$60	$56	$63	$58	$61
Strategic							
Security Enhancement Value	$23	$23	$23	$22	$23	$22	$22
Long Term Societal Value	$28	$29	$29	$27	$28	$28	$28
Total Strategic Value	$51	$52	$52	$49	$51	$50	$50
Other							
Fuel Price Hedge Value	$31	$42	$42	$47	$24	$44	$25
Generation Capacity Value	$22	$16	$17	$22	$19	$26	$18
T&D Capacity Value	$6	$1	$1	$3	$1	$8	$2
Market Price Reduction Value	$35	$67	$69	$54	$52	$51	$54
Environmental Value	$54	$55	$55	$52	$23	$22	$23
Economic Development Value	$44	$45	$45	$42	$45	$44	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($22)	($23)	($22)	($22)
Total Other Value	$170	$203	$206	$199	$143	$173	$144
Total Value	**$282**	**$315**	**$318**	**$304**	**$257**	**$280**	**$256**

Contents

Introduction: The Value of PV

This report attempts to quantify the value of distributed solar electricity in Pennsylvania and New Jersey. It uses methodologies and analytical tools that have been developed over several years. The framework supposes that PV is located in the distribution system. PV that is located close to the loads provides the highest value per unit of energy to the utility because line losses are avoided, thereby increasing the value of solar relative to centrally-located resources.

The value of PV may be considered the aggregate of several components, each estimated separately, described below. The methods used to calculate value are described in more detail in the Appendices.

Fuel Cost Savings

Distributed PV generation offsets the cost of power generation. Each kWh generated by PV results in one less unit of energy that the utility needs to purchase or generate. In addition, distributed PV reduces system losses so that the cost of the wholesale generation that would have been lost must also be considered.

Under this study, the value is defined as the cost of natural gas fuel that would otherwise have to be purchased to operate a gas turbine (CCGT) plant and meet electric loads and T&D losses. The study presumes that the energy delivered by PV displaces energy at this plant.

Whether the utility receives the fuel cost savings directly by avoiding fuel purchases, or indirectly by reducing wholesale power purchases, the method of calculating the value is the same.

O&M Cost Savings

Under the same mechanism described for Fuel Cost Savings, the utility realizes a savings in O&M costs due to decreased use of the CCGT plant. The cost savings are assumed to be proportional to the energy avoided, including loss savings.

Security Enhancement Value

The delivery of distributed PV energy correlated with load results in an improvement in overall system reliability. By reducing the risk of power outages and rolling blackouts, economic losses are reduced.

Long Term Societal Value

The study period is taken as 30 years (the nominal life of PV systems), and the calculation of value components includes the benefits provided over this study period. However, it is possible that the life can be longer than 30 years, in which case the full value would not be accounted for. This "long term societal value" is the potential extended benefit of all value components over a 10 year period beyond the study period. In other words, if the assumed life were 40 years instead of 30, the increase in total value is the long term societal value.

Fuel Price Hedge Value

PV generation is insensitive to the volatility of natural gas or other fuel prices, and therefore provides a hedge against price fluctuation. This is quantified by calculating the cost of a risk mitigation investment that would provide price certainty for future fuel purchases.

Generation Capacity Value

In addition to the fuel and O&M cost savings, the total cost of power generation includes capital cost. To the extent that PV displaces the need for generation capacity, it would be valued as the capital cost of displaced generation. The key to valuing this component is to determine the effective load carrying capability (ELCC) of the PV fleet, and this is accomplished through an analysis of hourly PV output relative to overall utility load.

T&D Capacity Value

In addition to capital cost savings for generation, PV potentially provides utilities with capital cost savings on T&D infrastructure. In this case, PV is not assumed to displace capital costs but rather defer the need. This is because local loads continue to grow and eventually necessitate the T&D capital investment. Therefore, the cost savings realized by distributed PV is merely the cost of capital saved in the intervening period between PV installation and the time at which loads again reach the level of effective PV capacity.

Market Price Reduction

PV generation reduces the amount of load on the utility systems, and therefor reduces the amount of energy purchased on the wholesale market. The demand curve shifts to the left, and the market clearing price is reduced. Thus, the presence of PV not only displaces the need for energy, but also reduces the cost of wholesale energy to all consumers. This value is quantified through an analysis of the supply curve and the reduction in demand.

Environmental Value

One of the primary motives for PV and other renewable energy sources is to reduce the environmental impact of power generation. Environmental benefits covered in this analysis represent future savings for mitigating environmental damage (sulfur dioxide emissions, water contamination, soil erosion, etc.).

Economic Development Value

Distributed PV provides local jobs (e.g., installers) at higher rates than conventional generation. These jobs, in turn, translate to tax revenue benefits to all taxpayers.

Solar Penetration Cost

In addition to the value provided by PV, there are costs that must be factored in as necessary to accept variable solar generation onto the grid. Infrastructural and operational expenses will be incurred to manage the flow of non-dispatchable PV resources. These costs are included as a negative value.

Value Perspective

The value of solar accrues either to the electric utility or to society (ratepayers and taxpayers), depending upon component. For example, PV reduces the amount of wholesale energy needed to serve load, resulting in savings to the utility. On the other hand, environmental mitigation costs accrue to society.

Approach

Locations

Seven locations were selected to provide broad geographical and utility coverage in the two states of interest (see Table 1). Four locations were selected in Pennsylvania representing three utilities[1] and three locations were selected in New Jersey, each served by a separate utility.

Table 1. Study location summary.

		Location	Utility	2011 Utility Peak Load (MW)	PV Fleet Capacity (MW)
PA	1	Pittsburgh	Duquesne Light Co.	3,164	475
	2	Scranton	PPL Utilities Corp.	7,527	1,129
	3	Harrisburg	PPL Utilities Corp.	7,527	1,129
	4	Philadelphia	PECO Energy Co.	8,984	1,348
NJ	5	Jamesburg	Jersey Central P&L	6,604	991
	6	Newark	PSE&G	10,933	1,640
	7	Atlantic City	Atlantic City Electric	2,956	443

These locations represent a diversity of input assumptions:

- The locations span two states: PA and NJ. These states differ in generation mix (percentage of coal, gas, nuclear, etc.), and this is reflected in different environmental cost assumptions (see Appendix 2).
- The locations differ in solar resource.

[1] Scranton and Harrisburg are both served by PPL Utilities.

- The locations represent six different utility service territories. Each of these utilities differ by cost of capital, hourly loads, T&D loss factors, distribution expansion costs, and growth rate.

Penetration Level

Fleet capacity was set to 15% of the utility peak load. This assumption was intended to represent a moderate long-term penetration level.

The value of solar per MWh decreases with increasing penetration for several reasons:

- The match between PV output and loads is reduced. As more PV is added to the resource mix, the peak shifts to non-solar hours, thereby limiting the ability of PV to support the peak.
- Line losses are related to the square of the load. Consequently, the greatest marginal savings provided by PV is achieved with small amounts of PV. By adding larger and larger quantities of PV, the loss savings continue to be gained, but at decreasing rates.
- Similarly, the market prices are non-linear, and PV is most effective in causing market price reduction with small PV capacity.

Based on the above considerations, this study is intended to represent a moderate level of long-term PV penetration. With penetration levels less than 15%, the value of solar would be expected to be higher than the results obtained in this study.

Peak loads for each utility were obtained from hourly load data corresponding to PJM load zones, and these were used to set the fleet capacity as shown in the table.

Fleet Configurations

Four PV system configurations were included in the study:

- South-30 (south-facing, 30-degree tilt, fixed)
- Horizontal (fixed)
- West-30 (west facing, 30-degree tilt, fixed)
- 1-Axis (tracking at 30-degree tilt)

These were selected in order to capture possible variations in value due to the different production profiles. For example, West-facing systems are sometimes found to be the best match with utility loads and have the potential to provide more capacity benefits. On the other hand, tracking systems deliver more energy per unit of rated output, so they have the potential to offer more energy benefits (e.g., fuel cost savings).

Scenarios and Fleet Modeling

Value was determined for each of 28 scenarios (four fleet configurations at each of seven locations). For modeling purposes, fleets were described by latitude and longitude coordinates, AC rating, a module derate factor (90%), inverter efficiency (95%) and other loss factor (90%). These factors were consistent across all scenarios.

Fleets were modeled for all hours of 2011 using SolarAnywhere® satellite-derived irradiance data and simulation model with a 10 km x 10 km pixel resolution. [2] Under this procedure, the fleet output for each scenario is location- and time-correlated with hourly PJM zonal loads.

[2] http://www.solaranywhere.com.

Results

Utility Analysis

Utility analysis results are shown in Table 2, obtained from an analysis of FERC filings and PJM hourly data using methods developed previously for NYSERDA.[3] These include:

- Utility discount rate
- Utility system loss data
- Distribution expansion costs (present value)
- Distribution load growth rate
- Distribution loss data

Note that actual utility costs are used in this analysis because they are the basis of value. For this reason, the utility cost of capital is required (e.g., an "assumed" or "common" value cannot be used). The results may therefore differ, in part, due to differences in utility discount rate.

PV Technical Analysis

A summary of fleet technical performance results is presented in Table 3. Annual energy production is the modeled output for 2011. Capacity factor is the annual energy production relative to a baseload plant operating at 100% availability with the same rated output. Generation capacity is Effective Load Carrying Capability (ELCC) expressed as a percentage of rated capacity. T&D Capacity is a measure of the direct annual peak-load reduction provided by the PV system expressed as a percentage of rated capacity.

[3] Norris and Hoff, "PV Valuation Tool," Final Report (DRAFT), NYSERDA, May 2012.

Table 2. Utility analysis results.

		Pittsburgh	Scranton	Harrisburg	Philadelphia	Jamesburg	Newark	Atlantic City
Utility		Duquesne Light Co.	PPL Utilities Corp.	PPL Utilities Corp.	PECO Energy Co.	Jersey Central P&L	PSE&G	Atlantic City Electric
UtilityID		DUQ	PPL	PPL	PECO	JCPL	PSEG	AECO
UTILITY DATA								
Economic Factors								
Discount Rate	percent per year	6.63%	8.08%	8.08%	9.00%	5.68%	8.46%	5.88%
Utility System								
Load Loss Condition	MW	1,757	4,786	4,786	4,958	2,893	5,435	1,369
Avg. Losses (at Condition)	percent	5.84%	6.55%	6.55%	4.23%	6.35%	4.86%	5.61%
Distribution								
Distribution Expansion Cost	$ PW	$485,009,880	$423,994,174	$423,994,174	$722,046,118	$446,914,440	$573,820,751	$288,330,547
Distribution Expansion Cost Escalation	percent per year	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%	3.89%
Distribution Load Growth Rate	MW per year	30.9	98.3	98.3	110.7	93.4	91.4	39.5
Load Loss Condition	MW	1,757	4,786	4,786	4,958	2,893	5,435	1,369
Avg. Losses (at Condition)	percent	5.84%	6.55%	6.55%	4.23%	6.35%	4.86%	5.61%

Table 3. Technical results, by location (South-30).

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Fleet Capacity (MWac)	475	1129	1129	1348	991	1640	443
Annual Energy Production (MWh)	716,621	1,809,443	1,698,897	2,339,424	1,675,189	2,677,626	827,924
Capacity Factor (%)	17%	18%	17%	20%	19%	19%	21%
Generation Capacity (% of Fleet Capacity)	41%	28%	28%	38%	45%	45%	46%
T&D Capacity (% of Fleet Capaccity)	31%	14%	14%	21%	29%	56%	36%

Value Analysis

Figure 1 shows the value results in levelized dollars per MWh generated. Figure 2 shows the data in dollars per kW installed. This data is also presented in tabular form in Table 4 and Table 5. Detailed results for individual locations are shown in Appendix 3.

The total value ranges from $256 per MWh to $318 per MWh. Of this, the highest value components are the Market Price Reduction (averaging $55 per MWh) and the Economic Development Value (averaging $44 per MWh).

The differences between Table 4 and Table 5 are due to differences in the cost of capital between the utilities. For example, Atlantic City has the highest value per installed kW, but Atlantic City Electric has one of the lowest calculated discount rates (Table 2). Therefore, when this value is levelized over the 30 year study period, it represents a relatively low value.

Other observations:

- **Market Price Reduction**. The two locations of highest total value (Harrisburg and Scranton) are noted for their high Market Price Reduction value. This may be the result of a good match between LMP and PV output. By reducing demand during the high priced hours, a cost savings is realized by all consumers. Further investigation of the methods may be warranted in light of two arguments put forth by Felder [32]: that the methodology does address induced increase in demand due to price reductions, and that it only addresses short-run effects (ignoring the impact on capacity markets).
- **Environmental Value**. The state energy mix is a differentiator of environmental value. Pennsylvania (with a large component of coal-fired generation in its mix) leads to higher environmental value in locations in that state relative to New Jersey. As described in Appendix 2, the PA generation mix is dominated by coal (48%) compared to NJ (10%).
- **T&D Capacity Value**. T&D capacity value is low for all scenarios, with the average value of only $3 per MWh. This may be explained by the conservative method taken for calculating the effective T&D capacity.
- **Fuel Price Hedge**. The cost of eliminating future fuel purchases—through the use of financial hedging instruments—is directly related to the utility's cost of capital. This may be seen by comparing the hedge value in Jamesburg and Atlantic City. At a rate of 5.68%, Jersey Central Power & Light (the utility serving Jamesburg) has the lowest calculated cost of capital among the

six utilities included in the study. In contrast, PSE&G (the utility serving Newark) has a calculated discount rate of 8.46%, the highest among the utilities. This is reflected in the relative hedge values of $24 per MWh for Jamesburg and $44 per MWh for Newark, nearly twice the value.

Figure 1. Levelized value ($/MWh), by location (South-30).

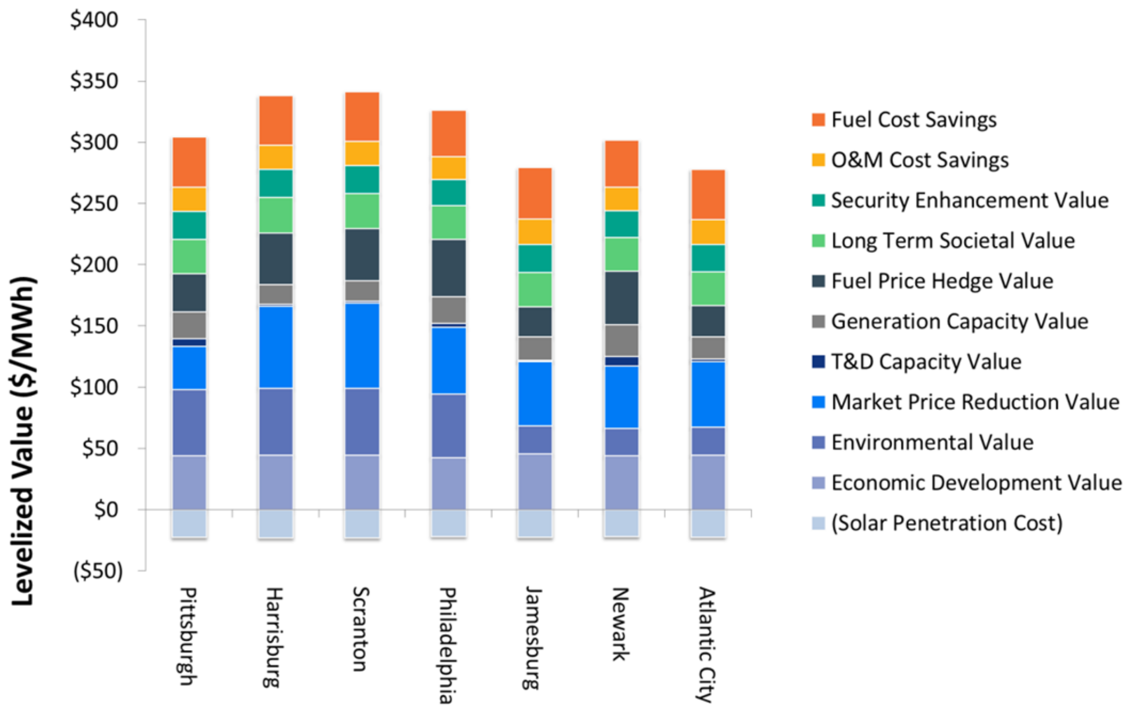


Figure 2. Value ($/kW), by location (South-30).

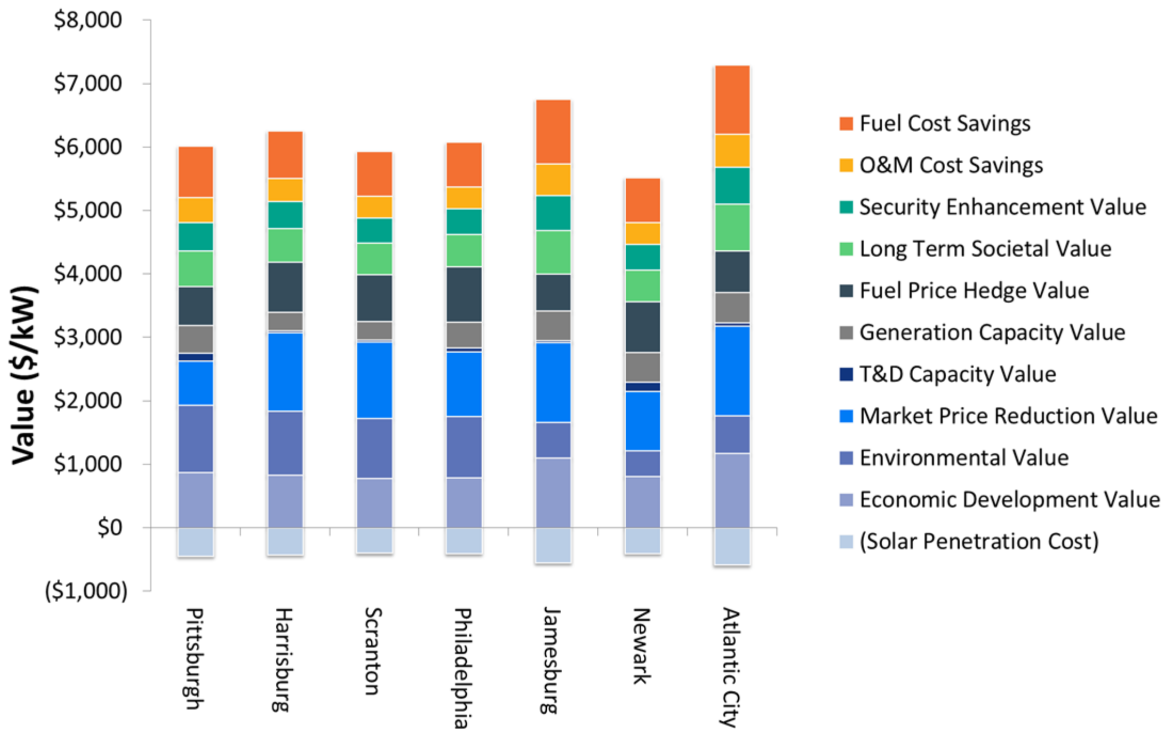


Table 4. Value (levelized $/MWh), by location (South-30).

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Energy							
Fuel Cost Savings	$41	$41	$41	$38	$42	$39	$41
O&M Cost Savings	$20	$20	$20	$18	$21	$19	$20
Total Energy Value	$61	$60	$60	$56	$63	$58	$61
Strategic							
Security Enhancement Value	$23	$23	$23	$22	$23	$22	$22
Long Term Societal Value	$28	$29	$29	$27	$28	$28	$28
Total Strategic Value	$51	$52	$52	$49	$51	$50	$50
Other							
Fuel Price Hedge Value	$31	$42	$42	$47	$24	$44	$25
Generation Capacity Value	$22	$16	$17	$22	$19	$26	$18
T&D Capacity Value	$6	$1	$1	$3	$1	$8	$2
Market Price Reduction Value	$35	$67	$69	$54	$52	$51	$54
Environmental Value	$54	$55	$55	$52	$23	$22	$23
Economic Development Value	$44	$45	$45	$42	$45	$44	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($22)	($23)	($22)	($22)
Total Other Value	$170	$203	$206	$199	$143	$173	$144
Total Value	**$282**	**$315**	**$318**	**$304**	**$257**	**$280**	**$256**

Table 5. Value ($/kW), by location (South-30).

	Pittsburgh	Harrisburg	Scranton	Philadelphia	Jamesburg	Newark	Atlantic City
Energy							
Fuel Cost Savings	$813	$751	$706	$706	$1,020	$709	$1,081
O&M Cost Savings	$396	$366	$344	$344	$497	$345	$527
Total Energy Value	$1,209	$1,117	$1,050	$1,049	$1,517	$1,054	$1,609
Strategic							
Security Enhancement Value	$446	$424	$398	$405	$549	$403	$584
Long Term Societal Value	$557	$530	$498	$507	$686	$504	$730
Total Strategic Value	$1,003	$954	$896	$912	$1,234	$907	$1,314
Other							
Fuel Price Hedge Value	$613	$786	$738	$876	$586	$798	$662
Generation Capacity Value	$432	$297	$290	$401	$468	$470	$478
T&D Capacity Value	$127	$24	$24	$65	$23	$147	$49
Market Price Reduction Value	$696	$1,241	$1,206	$1,013	$1,266	$927	$1,412
Environmental Value	$1,064	$1,011	$950	$967	$560	$411	$596
Economic Development Value	$870	$827	$777	$790	$1,097	$806	$1,168
(Solar Penetration Cost)	($446)	($424)	($398)	($405)	($549)	($403)	($584)
Total Other Value	$3,355	$3,761	$3,586	$3,706	$3,451	$3,156	$3,781
Total Value	**$5,568**	**$5,832**	**$5,532**	**$5,667**	**$6,202**	**$5,117**	**$6,704**

Future Work

In the course of conducting this study, several observations were made that suggest further refinement to these results should be considered:

- The market price reduction estimated as part of the present study will have to be ascertained as PV develops and penetrates the NJ and PA grids. In particular, the impact of PV-induced price reduction on load growth, hence feedback secondary load-growth induced market price increase as suggested by Felder [32] should be quantified. In addition, the feedback of market price reduction on capacity markets will have to be investigated.

- In this study 15% PV capacity penetration was assumed-- amounting to a total PV capacity of 7GW across the seven considered utility hubs. Since both integration cost increases and capacity value diminishes with penetration, it will be worthwhile to investigate other penetration scenarios. This may be particularly useful for PA where the penetration is smaller than NJ. In addition, it may be useful to see the scenarios with penetration above 15%. For these cases, it would be pertinent to establish the cost of displacing (nuclear) baseload generation with solar generation[4] since this question is often brought to the forefront by environmentally-concerned constituents in densely populated areas of NJ and PA.

- Other sensitivities may be important to assess as well. Sensitivities to fuel price assumptions, discount rates, and other factors could be investigated further. In particular the choice made here to use documented utility-specific discount rates and its impact on the per MWh levelized results[5] could be quantified and compared to an assumption using a common discount rate representative of average regional business practice.

- The T&D values derived for the present analysis are based on utility-wide average loads. Because this value is dependent upon the considered distribution system's characteristics – in particular load growth, customer mix and equipment age – the T&D value may vary considerably from one distribution feeder to another. It would therefore be advisable to take this study one step further and systematically identify the highest value areas. This will require the collaboration of the servicing utilities to provide relevant subsystem data.

[4] Considering integration solutions including storage, wind/PV synergy and gas generation backup.
[5] Note that the per kW value results are much less dependent upon the discount rate

Appendix 1: Detailed Assumptions

Input assumptions that are common across all of the scenarios are shown in Table 6.

Table 6. Input assumptions and units common to all scenarios.

INPUT ASSUMPTIONS		
PV Characteristics		
PV Degradation	0.50%	per year
PV System Life	30	years
Generation Factors		
Gen Capacity Cost	$1,045	per kW
Gen Heat Rate (First Year)	7050	BTU/kWh
Gen Plant Degradation	0.00%	per year
Gen O&M Cost (First Year)	$12.44	per MWh
Gen O&M Cost Escalation	3.38%	per year
Garver Percentage	5.00%	Pct of Ann Peak
NG Wholesale Market Factors		
End of Term NG Futures Price Escalation	2.33%	per year

PV degradation is assumed to be 0.50% per year indicating that the output of the system will degrade over time. This is a conservative assumption (PV degradation is likely to be less than 0.5% per year). Studies often ignore degradation altogether because the effect is small, but it is included here for completeness.

The study period is taken as 30 years, corresponding to typical PV lifetime assumptions.

PV is assumed to displace power generated from peaking plants fueled by natural gas. Gas turbine capital, O&M, heat rate, and escalation values are taken from the EIA.[6] Plant degradation is assumed to be zero.

[6] Updated Capital Cost Estimates for Electricity Generation Plants, U.S. Energy Information Administration, November 2010, available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf. Taken from Table 1, page 7. Costs are escalated to 2012 dollars.

Costs for generation O&M are assumed to escalate at 3.38%, calculated from the change in Producer Price Index (PPI) for the "Turbine and power transmission equipment manufacturing" industry[7] over the period 2004 to 2011.

Natural gas prices used in the fuel price savings value calculation are obtained from the NYMEX futures prices. These prices, however, are only available for the first 12 years. Ideally, one would have 30 years of futures prices. As a proxy for this value, it is assumed that escalation after year 12 is constant based on historically long term prices to cover the entire 30 years of the PV service life (years 13 to 30). The EIA published natural gas wellhead prices from 1922 to the present.[8] It is assumed that the price of the NG futures escalates at the same rate as the wellhead prices.[9] A 30-year time horizon is selected with 1981 gas prices at $1.98 per thousand cubic feet and 2011 prices at $3.95. This results in a natural gas escalation rate of 2.33%.

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[7] PPI data is downloadable from the Bureau industry index selected was taken as the most representative of power generation O&M. BLS does publish an index for "Electric power generation" but this is assumed.

[8] US Natural Gas Prices (Annual), EIA, release date 2/29/2012, available at http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

[9] The exact number could be determined by obtaining over-the-counter NG forward prices.

Appendix 2: Methodologies

Overview

The methodologies used in the present project drew upon studies performed by CPR for other states and utilities. In these studies, the key value components provided by PV were determined by CPR, using utility-provided data and other economic data.

The ability to determine value on a site-specific basis is essential to these studies. For example, the T&D Capacity Value component depends upon the ability of PV to reduce peak loads on the circuits. An analysis of this value, then, requires:

Hour by hour loads on distribution circuits of interest.

- Hourly expected PV outputs corresponding to the location of these circuits and expected PV system designs.
- Local distribution expansion plan costs and load growth projections.

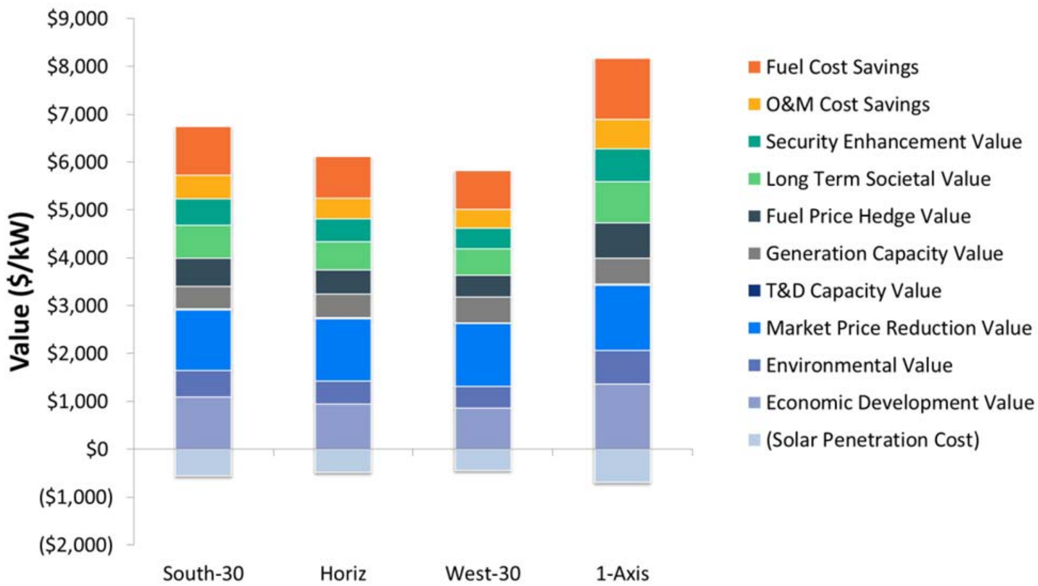
Units of Results

The discounting convention assumed throughout the report is that energy-related values occur at the end of each year and that capacity-related values occur immediately (i.e., no discounting is required).[10]

The Present Value results are converted to per unit value (Present Value $/kW) by dividing by the size of the PV system (kW). An example of this conversion is illustrated in Figure 3 for results from a previous study. The y-axis presents the per unit value and the x-axis presents seven different PV system configurations. The figure illustrates how value components can be significantly affected by PV system configuration. For example, the tracking systems, by virtue of their enhanced energy production capability, provide greater generation benefits.

[10] The effect of this will be most apparent in that the summations of cash flows start with the year equal to 1 rather than 0.

Figure 3. Sample results.



The present value results per unit of capacity ($/kW) are converted to levelized value results per unit of energy ($/MWh) by dividing present value results by the total annual energy produced by the PV system and then multiplying by an economic factor.

PV Production and Loss Savings

PV System Output

An accurate PV value analysis begins with a detailed estimate of PV system output. Some of the energy-based value components may only require the total amount of energy produced per year. Other value components, however, such as the energy loss savings and the capacity-based value components, require hourly PV system output in order to determine the technical match between PV system output and the load. As a result, the PV value analysis requires time-, location-, and configuration-specific PV system output data.

For example, suppose that a utility wants to determine the value of a 1 MW fixed PV system oriented at a 30° tilt facing in the southwest direction located at distribution feeder "A". Detailed PV output data that is time- and location-specific is required over some historical period, such as from Jan. 1, 2001 to Dec. 31, 2010.

Methodology

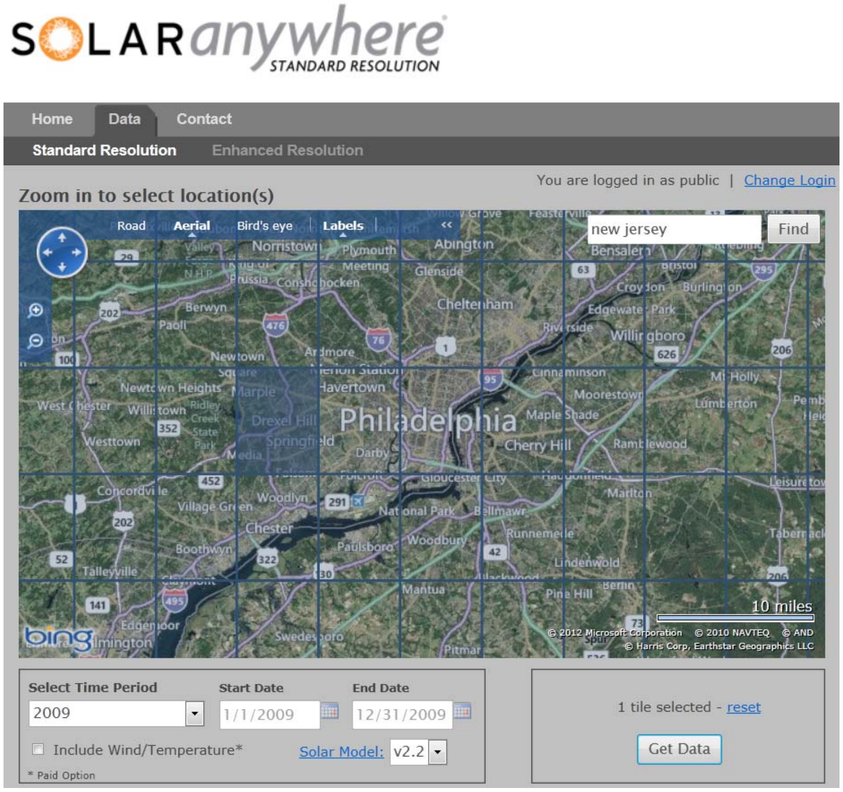
It would be tempting to use a representative year data source such as NREL's Typical Meteorological Year (TMY) data for purposes of performing a PV value analysis. While these data may be representative of long-term conditions, they are, by definition, not time-correlated with actual distribution line loading on an hourly basis and are therefore not usable in hourly side-by-side comparisons of PV and load. Peak substation loads measured, say, during a mid-August five-day heat wave must be analyzed alongside PV data that reflect the same five-day conditions. Consequently, a technical analysis based on anything other than time- and location-correlated solar data may give incorrect results.

CPR's SolarAnywhere® and PVSimulator™ software services will be employed under this project to create time-correlated PV output data. SolarAnywhere is a solar resource database containing almost 14 years of time- and location-specific, hourly insolation data throughout the continental U.S. and Hawaii. PVSimulator, available in the SolarAnywhere Toolkit, is a PV system modeling service that uses this hourly resource data and user-defined physical system attributes in order to simulate configuration-specific PV system output.

The SolarAnywhere data grid web interface is available at www.SolarAnywhere.com (Figure 4). The structure of the data allows the user to perform a detailed technical assessment of the match between PV system output and load data (even down to a specific feeder). Together, these two tools enable the evaluation of the technical match between PV system output and loads for any PV system size and orientation.

Previous PV value analyses were generally limited to a small number of possible PV system configurations due to the difficulty in obtaining time- and location-specific solar resource data. This new value analysis software service, however, will integrate seamlessly with SolarAnywhere and PVSimulator. This will allow users to readily select any PV system configuration. This will allow for the evaluation of a comprehensive set of scenarios with essentially no additional study cost.

Figure 4. SolarAnywhere data selection map.



Loss Savings

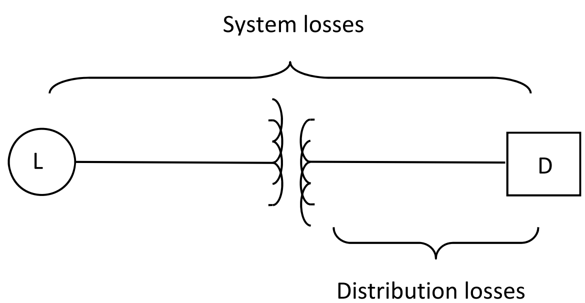
Introduction

Distributed resources reduce system losses because they produce power in the same location that the power is consumed, bypassing the T&D system and avoiding the associated losses.

Loss savings are not treated as a stand-alone benefit under the convention used in this methodology. Rather, the effect of loss savings is included separately for each value component. For example, in the section that covers the calculation of Energy Value, the quantity of energy saved by the utility includes both the energy produced by PV and the amount that would have been lost due to heating in the wires if the load were served from a remote source. The total energy that would have been procured by the utility equals the PV energy plus avoided line losses. Loss savings can be considered a sort of "adder" for each benefit component.

This section describes the methodology for calculating loss savings for each hour. The results of these calculations are then used in subsequent sections. As illustrated in Figure 5, it will be important to note that, while the methodology describes the calculation of an hourly loss result, there are actually two different loss calculations that must be performed: “system” losses, representing the losses incurred on both the transmission and distribution systems (between generation load, L, and end-use demand, D), and “distribution” losses, representing losses specific to distribution system alone.

Figure 5. System losses versus distribution losses.



The two losses are calculated using the same equation, but they are each applicable in different situations. For example, “Energy Value” represents a benefit originating at the point of central generation, so that the total system losses should be included. On the other hand, “T&D Capacity Value” represents a benefit as measured at a distribution substation. Therefore, only the losses saved on the distribution system should be considered.

The selection of “system” versus “distribution” losses is discussed separately for each subsequent benefit section.

Methodology

One approach analysts have used to incorporate losses is to adjust energy- and capacity-related benefits based on the *average* system losses. This approach has been shown to be deficient because it fails to capture the true reduction in losses on a marginal basis. In particular, the approach underestimates the reduction in losses due to a peaking resource like PV. Results from earlier studies demonstrated that loss savings calculations may be off by more than a factor of two if not performed correctly [6].

For this reason, the present methodology will incorporate a calculation of loss savings on a marginal basis, taking into account the status of the utility grid when the losses occur. Clean Power Research has previously developed methodologies based on the assumption that the distributed PV resource is small relative to the load (e.g., [6], [9]). CPR has recently completed new research that expands this methodology so that loss savings can now be determined for any level of PV penetration.

Fuel Cost Savings and O&M Cost Savings

Introduction

Fuel Cost Savings and O&M Cost Savings are the benefits that utility participants derive from using distributed PV generation to offset wholesale energy purchases or reduce generation costs. Each kWh generated by PV results in one less unit of energy that the utility needs to purchase or generate. In addition, distributed PV reduces system losses so that the cost of the wholesale generation that would have been lost must also be considered. The capacity value of generation is treated in a separate section.

Methodology

These values can be calculated by multiplying PV system output times the cost of the generation on the margin for each hour, summing for all hours over the year, and then discounting the results for each year over the life of the PV system.

There are two approaches to obtaining the marginal cost data. One approach is to obtain the marginal costs based on historical or projected market prices. The second approach is to obtain the marginal costs based on the cost of operating a representative generator that is on the margin.

Initially, it may be appealing to take the approach of using market prices. There are, however, several difficulties with this approach. One difficulty is that these tend to be hourly prices and thus require hourly PV system output data in order to calculate the economic value. This difficulty can be addressed by using historical prices and historical PV system output to evaluate what results would have been in the past and then escalating the results for future projections. A more serious difficulty is that, while hourly market prices could be projected for a few years into the future, the analysis needs to be performed over a much longer time period (typically 30 years). It is difficult to accurately project hourly market prices 30 years into the future.

A more robust approach is to explicitly specify the marginal generator and then to calculate the cost of the generation from this unit. This is often a Combined Cycle Gas Turbine (CCGT) powered using natural gas (e.g., [6]). This approach includes the assumption that PV output always displaces energy from the same marginal unit. Given the uncertainties and complications in market price projections, the second approach is taken.

Fuel Cost Savings and O&M Cost Savings equals the sum of the discounted fuel cost savings and the discounted O&M cost savings.

Security Enhancement Value

Because solar generation is closely correlated with load in much of the US, including New Jersey and Pennsylvania [26], the injection of solar energy near point of use can deliver effective capacity, and therefore reduce the risk of the power outages and rolling blackouts that are caused by high demand and resulting stresses on the transmission and distribution systems.

The effective capacity value of PV accrues to the ratepayer (see above) both at the transmission and distribution levels. It is thus possible to argue that the reserve margins required by regulators would account for this new capacity, hence that no increased outage risk reduction capability would occur beyond the pre-PV conditions. This is the reason this value item above is not included as one of the directly quantifiable attributes of PV.

On the other hand there is ample evidence that during heat wave-driven extreme conditions, the availability of PV is higher than suggested by the effective capacity (reflecting of all conditions) -- e.g., see [27], [28], on the subject of major western and eastern outages, and [29] on the subject of localized rolling blackouts. In addition, unlike conventional centralized generation injecting electricity (capacity) at specific points on the grid, PV acts as a load modulator that provides immediate stress relief throughout the grid where stress exists due to high-demand conditions. It is therefore possible to argue that, all conditions remaining the same in terms of reserve margins, a load-side dispersed PV resource would mitigate issues leading to high-demand-driven localized and regional outages.

Losses resulting from power outages are generally not a utility's (ratepayers') responsibility: society pays the price, via losses of goods and business, compounded impacts on the economy and taxes, insurance premiums, etc. The total cost of all power outages from all causes to the US economy has been estimated at $100 billion per year (Gellings & Yeager, 2004). Making the conservative assumption that a small fraction of these outages, 5%, are of the high-demand stress type that can be effectively mitigated by dispersed solar generation at a capacity penetration of 15%,[11] it is straightforward to calculate, as shown below, that, nationally, the value of each kWh generated by such a dispersed solar base would be of the order of $20/MWh to the taxpayer.

The US generating capacity is roughly equal to 1000 GW. At 15% capacity penetration, taking a national average of 1500 kWh (slightly higher nationwide than PA and NJ) generated per year per installed kW, PV would generate 225,000 GWh/year. By reducing the risk of outage by 5%, the value of this energy would thus be worth $5 billion, amounting to $20 per PV-generated MWh.

This national value of $20 per MWh was taken for the present study because the underlying estimate of cost was available on a national basis. In reality, there would be state-level differences from this estimate, but these are not available.

Long Term Societal Value

This item is an attempt to place a present-value $/MWh on the generally well accepted argument that solar energy is a good investment for our children and grandchildren's well-being. Considering:

1. The rapid growth of large new world economies and the finite reserves of conventional fuels now powering the world economies, it is likely that fuel prices will continue to rise exponentially fast for the long term beyond the 30-year business life cycle considered here.
2. The known very slow degradation of the leading (silicon) PV technology, many PV systems installed today will continue to generate power at costs unaffected by the world fuel markets after their guaranteed lifetimes of 25-30 years

One approach to quantify this type of long-view attribute has been to apply a very low societal discount rate (e.g., 2% or less, see [25]) to mitigate the fact that the present-day importance of long-term expenses/benefits is essentially ignored in business as usual practice. This is because discount rates are

[11] Much less than that would have prevented the 2003 NE blackout. See [30].

used to quantify the present worth of future events and that, and therefore, long-term risks and attributes are largely irrelevant to current decision making.

Here a less controversial approach is proposed by arguing that, on average, PV installation will deliver, on average, a minimum of 10 extra years of essentially free energy production beyond the life cycle considered in this study.

The present value of these extra 10 years, all other assumptions on fuel cost escalation, inflation, discount rate, PV output degradation, etc. remaining the same, amounts to ~ $25/MWh for all the cities/PJM hubs considered in this study.

Fuel Price Hedge Value

Introduction

Solar-based generation is insensitive to the volatility of fuel prices while fossil-based generation is directly tied to fuel prices. Solar generation, therefore, offers a "hedge" against fuel price volatility. One way this has been accounted for is to quantify the value of PV's hedge against fluctuating natural gas prices [6].

Methodology

The key to calculating the Fuel Price Hedge Value is to effectively convert the fossil-based generation investment from one that has substantial fuel price uncertainty to one that has no fuel price uncertainty. This can be accomplished by entering into a binding commitment to purchase a lifetime's worth of fuel to be delivered as needed. The utility could set aside the entire fuel cost obligation up front, investing it in risk-fee securities to be drawn from each year as required to meet the obligation. The approach uses two financial instruments: risk-free, zero-coupon bonds[12] and a set of natural gas futures contracts.

Consider how this might work. Suppose that the CCGT operator wants to lock in a fixed price contract for a sufficient quantity of natural gas to operate the plant for one month, one year in the future. First, the operator would determine how much natural gas will be needed. If E units of electricity are to be generated and the heat rate of the plant is H, $E * H$ BTUs of natural gas will be needed. Second, if the corresponding futures price of this natural gas is $P^{NG\ Futures}$ (in $ per BTU), then the operator will need $E *$

[12] A zero coupon bond does not make any periodic interest payments.

$H * P^{NG\ Futures}$ dollars to purchase the natural gas one year from now. Third, the operator needs to set the money aside in a risk-free investment, typically a risk-free bond (rate-of-return of $r^{risk\text{-}free}$ percent) to guarantee that the money will be available when it is needed one year from now. Therefore, the operator would immediately enter into a futures contract and purchase $E * H * P^{NG\ Futures} / (1+ r^{risk\text{-}free})$ dollars worth of risk-free, zero-coupon bonds in order to guarantee with certainty that the financial commitment (to purchase the fuel at the contract price at the specified time) will be satisfied.[13]

This calculation is repeated over the life of the plant to calculate the Fuel Price Hedge value.

Generation Capacity Value

Introduction

Generation Capacity Value is the benefit from added capacity provided to the generation system by distributed PV. Two different approaches can be taken to evaluating the Generation Capacity Value component. One approach is to obtain the marginal costs based on market prices. The second approach is to estimate the marginal costs based on the cost of operating a representative generator that is on the margin, typically a Combined Cycle Gas Turbine (CCGT) powered by natural gas.

Methodology

The second approach is taken here for purposes of simplicity. Future version of the software service may add a market price option.

Once the cost data for the fully-dispatchable CCGT are obtained, the match between PV system output and utility loads needs to be determined in order to determine the effective value of the non-dispatchable PV resource. CPR developed a methodology to calculate the effective capacity of a PV system to the utility generation system (see [10] and [11]) and Perez advanced this method and called it the Effective Load Carrying Capability (ELCC) [12]. The ELCC method has been identified by the utility industry as one of the preferable methods to evaluate PV capacity [13] and has been applied to a variety of places, including New York City [14].

The ELCC is a statistical measure of effective capacity. The ELCC of a generating unit in a utility grid is defined as the load increase (MW) that the system can carry while maintaining the designated reliability

[13] $[E * H * P^{NG\ Futures} / (1+ r^{risk\text{-}free})] * (1+ r^{risk\text{-}free}) = E * H * P^{NG\ Futures}$

criteria (e.g., constant loss of load probability). The ELCC is obtained by analyzing a statistically significant time series of the unit's output and of the utility's power requirements.

Generation Capacity Value equals the capital cost ($/MW) of the displaced generation unit times the effective capacity provided by the PV.

T&D Capacity Value

Introduction

The benefit that can be most affected by the PV system's location is the T&D Capacity Value. The T&D Capacity Value depends on the existence of location-specific projected expansion plan costs to ensure reliability over the coming years as the loads grow. Capacity-constrained areas where loads are expected to reach critical limits present more favorable locations for PV to the extent that PV will relieve the constraints, providing more value to the utility than those areas where capacity is not constrained.

Distributed PV generation reduces the burden on the distribution system. It appears as a "negative load" during the daylight hours from the perspective of the distribution operator. Distributed PV may be considered equivalent to distribution capacity from the perspective of the distribution planner, provided that PV generation occurs at the time of the local distribution peak.

Distributed PV capacity located in an area of growing loads allows a utility planner to defer capital investments in distribution equipment such as substations and lines. The value is determined by the avoided cost of money due to the capital deferral.

Methodology

It has been demonstrated that the T&D Capacity Value can be quantified in a two-step process. The first step is to perform an economic screening of all areas to determine the expansion plan costs and load growth rates for each planning area. The second step is to perform a technical load-matching analysis for the most promising locations [18].

Market Price Reduction Value

Two cost savings occur when distributed PV generation is deployed in a market that is structured where the last unit of generation sets the price for all generation and the price is an increasing function of load. First, there is the direct savings that occur due to a reduction in load. This is the same as the value of energy provided at the market price of power. Second, there is the indirect value of market price reduction. Distributed generation reduces market demand and this results in lower prices to all those purchasing power from the market. This section outlines how to calculate the market savings value.

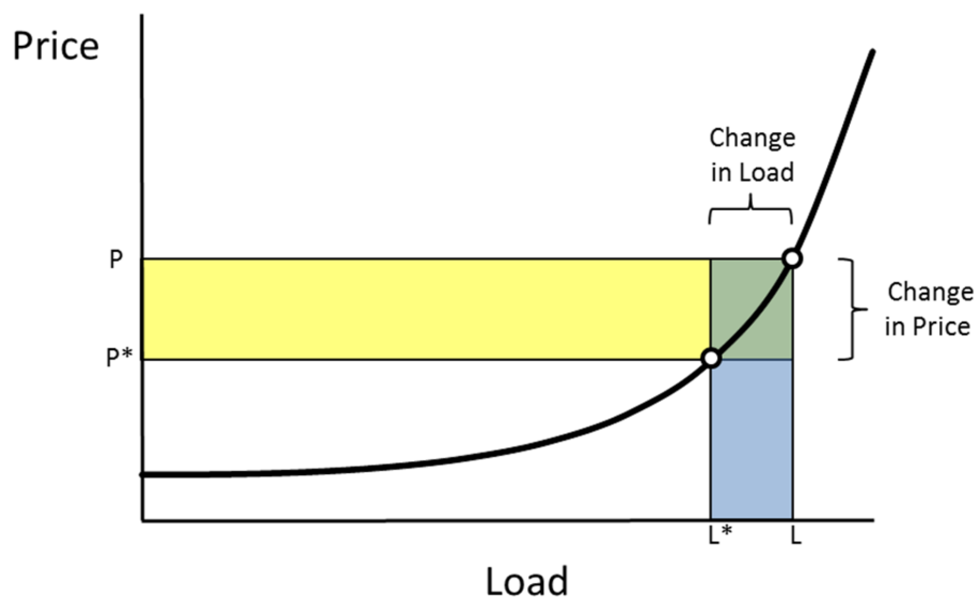
Cost Savings

As illustrated in Figure 6, the total market expenditures at any given point in time are based on the current price of power (P) and the current load (L). The rate of expenditure equals P L. Total market expenditures after PV is deployed equals the new price (P*) times the new load (L*), or P*L*. Cost savings equal the difference between the total before and after expenditures.

$$Cost\ Savings = P\ L - P^{*}L^{*} \quad \textbf{(1)}$$

The figure illustrates that the cost savings occur because there is both a change in load and a change in price.

Figure 6. Illustration of price changes that occur in market as result of load changes.



Equation (1) can be expanded by adding $-P^{*}L + P^{*}L$ and then rearranging the result.

$$Cost\ Savings \quad = P\ L + (-P^{*}L + P^{*}L) - P^{*}L^{*} \quad (2)$$

$$= (P - P^*)L + P^*(L - L^*)$$

$$= \left[\left(\frac{P - P^*}{L - L^*}\right)L + P^*\right](L - L^*)$$

Let $\Delta L = L - L^*$ and $\Delta P = P - P^*$ and substitute into Equation (2). The result is that

$$Cost\ Savings = \left[P + \frac{\Delta P}{\Delta L}L - \Delta P\right]\Delta L \tag{3}$$

Per unit cost savings is obtained by dividing Equation (3) by ΔL.

$$Per\ Unit\ Cost\ Savings = \overbrace{P}^{Direct\ Savings} + \overbrace{\frac{\Delta P}{\Delta L}L - \Delta P}^{Market\ Price\ Reduction\ Value} \tag{4}$$

Discussion

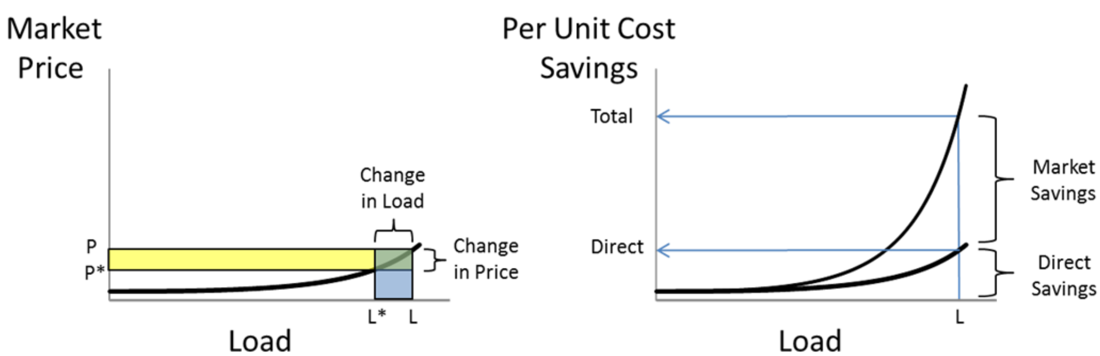
Equation (4) suggests that there are two cost savings components: direct savings and market price suppression. The direct savings equal the existing market price of power. The market price reduction value is the savings that the entire market realizes as a result of the load reduction. These savings depends on the change in load, change in price, and existing load. It is important to note that the change in load and the existing load can be measured directly while the change in price cannot be measured directly. This means that the change in price must be modeled (rather than measured).

It is useful to provide an interpretation of the market price reduction component and illustrate the potential magnitude. The market price reduction component in Equation (4) has two terms. The first term is the slope of the price curve (i.e., it is the derivative as the change in load goes to zero) times the existing load. This is the positive benefit that the whole market obtains due to price reductions. The second term is the reduced price associated with the direct savings.

The left side of Figure 7 presents the same information as in Figure 6, but zooms out on the y-axis scale of the chart. The first term corresponds to the yellow area. The second term corresponds to the overlapping areas of the change in price and change in load effects.

The market price curve can be translated to a cost savings curve. The right side of Figure 7 presents the per unit cost savings based on the information from the market price curve (i.e., the left side of the figure). The lower black line is the price vs. load curve. The upper line adds the market price suppression component to the direct savings component. It assumes that there is the same load reduction for all loads as in the left side of the figure. The figure illustrates that no market price suppression exist when the load is low but the market price suppression exceed the direct cost savings when the load is high. The saving is dependent upon the shape of the price curve and the size of the load reduction.

Figure 7. Direct + market price reduction vs. load (assuming constant load reduction).



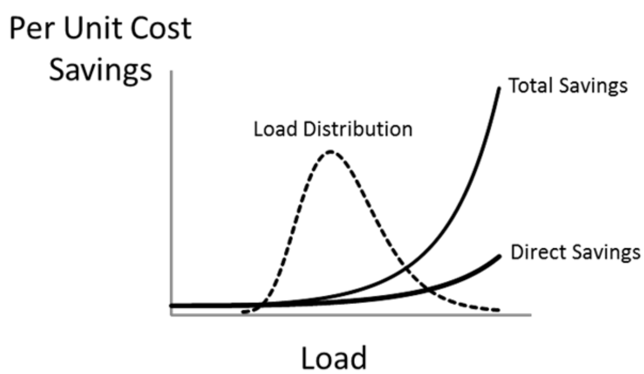
Total Value

The previous sections calculated the cost savings at a specific instant in time. The total cost savings is calculated by summing this result overall all periods in time. The per unit cost savings is calculated by dividing by the total energy. (Note that it is assumed that each unit of time represents 1 unit). The result is that:

$$Per\ Unit\ Cost\ Savings = \frac{Total\ Cost\ Savings}{Total\ Energy} = \frac{\sum_{t=1}^{T}\left[P_t + \frac{\Delta P_t}{\Delta L_t} L_t - \Delta P_t\right]\Delta L_t}{\sum_{t=1}^{T}\Delta L_t} \qquad (5)$$

This result can be viewed graphically as the probability distribution of the load times the associate cost savings curves when there is a constant load reduction. Multiply the load distribution by the total per unit savings to obtain the weighted average per unit cost savings.

Figure 8. Apply load distribution to calculate total savings over time.



Application

As discussed above, all of the parameters required to perform this calculation can be measured directly except for the change in price. Thus, it is crucial to determine how to estimate the change in price.

This is implemented in four steps:

1. Obtain LMP price data and develop a model that reflects this data.
2. Use the LMP price model and Equation (4) to calculate the price suppression benefit. Note that this depends upon the size of the change in load.
3. Obtain time-correlated PV system output and determine the distribution of this output relative to the load.
4. Multiply the PV output distribution times the price suppression benefit to calculate the weighted-average benefit.

Historical LMP and time- and location-correlated PV output data are required to perform the analysis. LMPs are obtained from the market and the PV output data are obtained by simulating time- and location-specific PV output using SolarAnywhere.

Figure 9 illustrates how to perform the calculations using measured prices and simulated PV output for PPL in June 2012. The left side of the figure illustrates that the historical LMPs (black circles) are used to develop a price model (solid black line). The center of the figure illustrates how the price model is used with Equation (4) is used to calculate the price suppression benefit for every load level. Since this benefit depends upon the size of the change in the load, the figure presents a range. The solid blue line is the benefit for a very small PV output. The dashed blue line corresponds to the benefit for a 1,000 MW PV output. The right side of the figure (red line) presents the distribution of the PV energy relative to the load (i.e., the amount of PV energy produced at each load level, so higher values correspond to more frequent weighting). The weighted-average price suppression benefit is calculated by multiply the PV output distribution times the price suppression benefit. Note that in practice, the actual calculation is performed for each hour of the analysis since the price suppression benefit is a function of both the load and the PV output.

Figure 9. Illustration of how to calculate benefit using measured data for June 2011.

Step 1:	Step 2:	Step 3:
Develop price model based on measured LMP data	Calculate price reduction benefit (depends on output)	Develop PV output distribution

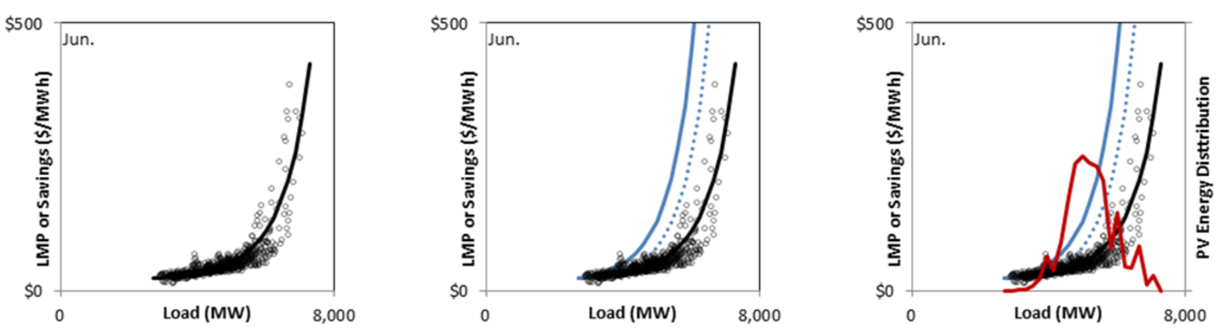
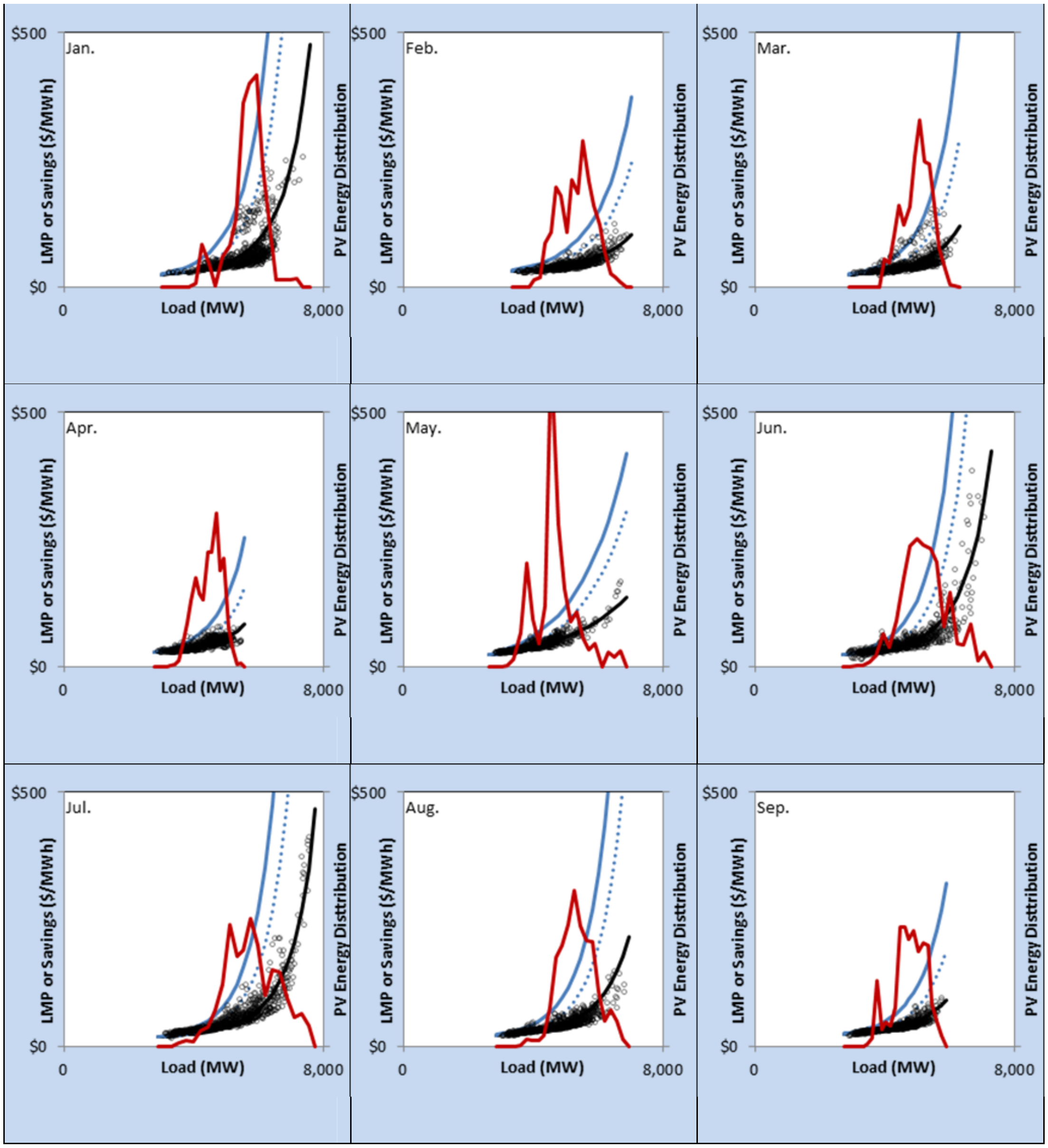
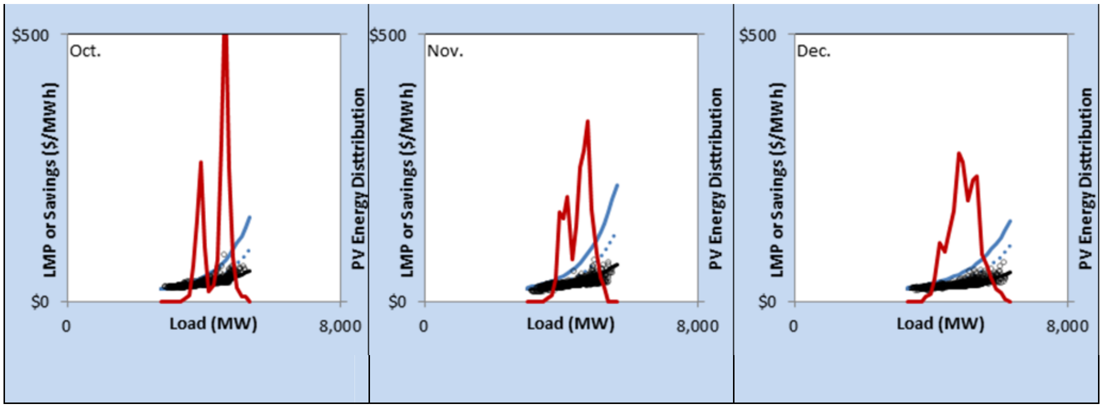


Figure 10 presents the results for the three steps for each month in 2011.

Figure 10. Measured and modeled LMPs (black circles and lines), price suppression benefit (solid blue for small output and dashed blue for 1,000 MW of output) and PV output distribution (PPL 2011).





Results

As illustrated in Table 7 the price reduction benefits are more than double the direct savings for a 100 MW of PV and slightly exceed the direct saving for 1,000 MW PV, for a combined value ranging from $127/MWh to $180/MWh.

Table 7. Market savings illustration.

	100 MW	1,000 MW
Direct Savings	$58	$58
Market Price Reduction	$122	$69
Total	$180	$127

A comparison of direct market savings and energy savings as calculated in this study is shown in Table 8. Fuel cost savings and O&M cost savings are combined because they represent the same costs that are included in market price. Direct savings were calculated for each hour as P·ΔL, summed for the year, and escalated at the same rate each year as natural gas futures beyond the 12 year limit.

Table 8. Direct market savings comparison (Newark, South-30).

	Value ($/kW)	Value ($/MWh)
Fuel Cost Savings	$709	38.8
O&M Cost Savings	$345	18.9
Total Energy Savings	**$1,054**	**57.7**
Direct Market Savings	**$1,470**	**80.4**

The results show that direct market savings are 39% above the energy savings. This discrepancy reflects the fact that the two quantities, while representing the same value components, use entirely different approaches. Fuel cost savings are derived from natural gas futures, discounted at the utility discount rate, and applied against an assumed CCGT heat rate. Direct market savings are based on hourly PJM zonal prices for 2011.

The energy savings achieved by the utility is based on avoided market purchases. However, historical market prices are not necessarily an indicator of future years, especially for 30 years into the future. For this reason, the energy savings methodology used in this analysis is more closely tied to the fundamentals of the cost: fuel and O&M costs that must be recovered by the marketplace for generation to be sustainable in the long run.

Zonal Price Model

To calculate the market price reduction in equation (4), a zonal price model was developed as follows. A function F() may be defined whose value is proportional to market clearing price using the form:

$$F(Load) = Ae^{BxLoad^{C}+D}$$

where coefficients A, B, C, and D are evaluated for each utility and for each month using hourly PJM zonal market price data, amounting to a total of 84 individual models.

P is the zonal wholesale clearing price, and P* is given by:

$$\frac{P^*}{P} = \frac{F(Load - FleetPower - LossSavings)}{F(Load)}$$

The market price reduction (in $/MWh) is calculated using the relevant term in Equation (4) and multiplying by the change in load, including loss savings.

Environmental Value

Introduction

It is well established that the environmental impact of PV is considerably smaller than that of fossil-based generation since PV is able to displace pollution associated with drilling/mining, and power plant emissions [15].

Methodology

There are two general approaches to quantifying the Environmental Value of PV: a regulatory cost-based approach and an environmental/health cost-based approach.

The regulatory cost-based approach values the Environmental Value of PV based on the price of Renewable Energy Credits (RECs) or Solar Renewable Energy Credits (SRECs) that would otherwise have to be purchased to satisfy state Renewable Portfolio Standards (RPS). These costs are a preliminary legislative attempt to quantify external costs. They represent actual business costs faced by utilities in certain states.

An environmental/health cost-based approach quantifies the societal costs resulting from fossil generation. Each solar kWh displaces an otherwise dirty kWh and commensurately mitigates several of the following factors: greenhouse gases, SOx/NOx emissions, mining degradations, ground water contamination, toxic releases and wastes, etc., that are all present or postponed costs to society. Several exhaustive studies have estimated the environmental/health cost of energy generated by fossil-based generation [16], [17]. The results from environmental/health cost-based approach often vary widely and can be controversial.

The environmental/health cost-based approach was used for this study.

The environmental footprint of solar generation is considerably smaller than that of the fossil fuel technologies generating most of our electricity (e.g., [19]). Utilities have to account for this environmental impact to some degree today, but this is still only largely a potential cost to them. Rate-based Solar Renewable Energy Credits (SRECs) markets in New Jersey and Pennsylvania as a means to meet Renewable Portfolio Standards (RPS) are a preliminary embodiment of including external costs, but they are largely driven more by politically-negotiated processes than by a reflection of inherent physical realities. The intrinsic physical value of displacing pollution is real and quantifiable however: depending on the current generation mix, each solar kWh displaces an otherwise dirty kWh and commensurately mitigates several of the following factors: greenhouse gases, SOx/NOx emissions, mining degradations, ground water contamination, toxic releases and wastes, etc., which are all present or postponed costs to society (i.e., the taxpayers).

The environmental value, EV, of each kWh produced by PV (i.e., not produced by another conventional source) is given by:

$$EV = \sum_{i=0}^{n} x_i \, EC_i$$

Where EC_i is the environmental cost of the displaced conventional generation technology and x_i is the proportion of this technology in the current energy mix.

Several exhaustive studies emanating from such diverse sources as the nuclear industry or the medical community ([20], [21]) estimate the environmental/health cost of 1 MWh generated by coal at $90-250, while a [non-shale[14]] natural gas MWh has an environmental cost of $30-60.

Considering New Jersey and Pennsylvania's electrical generation mixes (Table 9) and assuming that (1) nuclear energy is not displaced by PV at the assumed penetration level[15] and (2) that all natural gas is conventional, the environmental value of each MWh displaced by PV, hence the taxpayer benefit, is estimated at $48 to $129 in Pennsylvania and $20 to $48 in New Jersey.

We retained a value near the lower range of these estimates for the present analysis.

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[14] Shale gas environmental footprint is likely higher both in terms of environment degradation and GHG emissions.

[15] The study therefore ascribes no environmental value related to nuclear generation. Scenarios can certainly be designed in which nuclear generation would be displaced, in which case the environmental cost of nuclear generation would have to be considered. This is a complex and controversial subject that reflects the probability of catastrophic accidents and the environmental footprint of the existing uranium cycle. The fact that the environmental liability is assumed to be zero under the present study may therefore be considered a conservative case.

Table 9. Environmental input calculation.

	Generation Mix		Prorated Environmental Cost ($/MWh)		
Pennsylvania	48%	Coal	43.2	to	120.0
	15%	Natural Gas	4.5	to	9.0
	34%	Nuclear	0.0	to	0.0
	3%	Other	0.0	to	0.0
	Environmental Value for PA		47.7	to	129.0
New Jersey	10%	Coal	9.0	to	25.0
	38%	Natural Gas	11.4	to	22.8
	50%	Nuclear	0.0	to	0.0
	2%	Other	0.0	to	0.0
	Environmental Value for NJ		20.4	to	47.8

Economic Development Value

The German and Ontario experiences as well as the experience in New Jersey, where fast PV growth is occurring, show that solar energy sustains more jobs per unit of energy generated than conventional energy ([21], [22]). Job creation implies value to society in many ways, including increased tax revenues, reduced unemployment, and an increase in general confidence conducive to business development.

In this report, only tax revenue enhancement from the jobs created as a measure of PV-induced economic development value is considered. This metric provides a tangible low estimate of solar energy's likely larger multifaceted economic development value. In Pennsylvania and New Jersey, this low estimate amounts to respectively $39 and $40 per MWh, even under the very conservative, but thus far realistic, assumption that 80% of the PV manufacturing jobs would be either out-of-state or foreign (see methodology section, below).

Methodology

In a previous (New York) study [24], net PV-related job creation numbers were used directly based upon Ontario and Germany's historical numbers. However this assumption does not reflects the rapid changes of the PV industry towards lower prices. In this study a first principle approach is applied based upon the difference between the installed cost of PV and conventional generation: in essence this approach quantifies the fact that part of the price premium paid for PV vs. conventional generation returns to the local economy in the form of jobs hence tax.

Therefore, assuming that:

- Turnkey PV costs $3,000 per kW vs. $1,000 per kW for combine cycle gas turbines (CCGT)
- Turnkey PV cost is composed of 1/3 technology (modules & inverter/controls) and 2/3 structure and installation and soft costs.
- 20% of the turnkey PV technology cost and 90% of the other costs are traceable to local jobs, while 50% of the CCGT are assumed to be local jobs, thus:
  - The local jobs-traceable amount spent on PV is equal to: $\left(\frac{0.2}{3}+\frac{0.9\times2}{3}\right)\times3000=\$1{,}990/kW$
  - And the local jobs-traceable amount spent on CCGT is equal to: $0.5\times1000=\$500/kW$
- PV systems in NJ and PA have a capacity factor of ~ 16%, producing ~ 1,400 kWh per year per kW_{AC} and CCGT have an assumed capacity factor of 50%, producing 4,380 kWh per year, therefore
  - The local jobs-traceable amount spent per PV kWh in year one is: 1,900/1,400 = $1.42
  - The local jobs-traceable amount spent per CCGT kWh in year one is: 500/4,380 = $0.114
- The net local jobs-traceable between PV and CCGT is thus equal to 1.42-0.11 = $1.30
- Assuming that the life span of both PV and CCGT is 30 years, and using a levelizing factor of 8%, the net local jobs-traceable amount per generated PV kWh over its lifetime amounts to: $1.30\times\frac{0.08\times1.08^{30}}{1.08^{29}}=$ $0.116/kWh
- Assuming that locally-traceable O&M costs per kWh for PV are equal to the locally-traceable O&M costs for CCGT, [16] but also assuming that because PV-related T&D benefits displace a commensurate amount of utility jobs assumed to be equal to this benefit (~0.5 cents per kWh), the net lifetime locally-traceable PV-CCGT difference is equal to 0.116-0.005 = $0.111/kWh
- Finally assuming that each PV job is worth $75K/year after standard deductions – hence has a combined State and Federal income tax rate of 22.29% in PA and 22.67% in NJ[17] -- and that each

[16] This includes only a fraction of the fuel costs – the other fraction being imported from out-of-state.

[17] For the considered solar job income level, the effective state rate = 3.07% in PA and 3.54% in NJ and the effective federal rate = 19.83%. The increased federal tax collection is counted as an increase for New Jersey's

new job has an indirect job multiplier of 1.6,[18] it can be argued that each PV MWh represents a net new-job related tax collection increase for NJ equal to a levelized value of $\$111/\mathrm{MWh} \times 0.2267 \times 1.6 = \$40/\mathrm{MWh}$, and a tax collection increase for PA equal to $\$111/\mathrm{MWh} \times 0.2229 \times 1.6 = \$39/\mathrm{MWh}$.

Solar Penetration Cost

It is important to recognize that there is also a cost associated with the deployment of solar generation on the power grid which accrues to the utility and to its ratepayers. This cost represents the infrastructural and operational expense that will be necessary to manage the flow of non-controllable solar energy generation while continuing to reliably meet demand. A recent study by Perez et al. [31] showed that in much of the US, this cost is negligible at low penetration and remains manageable for a solar capacity penetration of 30%. For utilities representative of the demand pattern and solar load synergies found in Pennsylvania, this penetration cost has been found to range from 0 to 5 cents per kWh when PV penetration ranges from 0% to 30% in capacity. Up to this level of penetration, the infrastructural and operational expense would consist of localized load management, [user-sited] storage and/or backup.[19] At the 15% level of penetration considered in this study, the cost of penetration can be estimated from the Perez et al. study[18] at $10-20/MWh.

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taxpayer, because it can be reasonably argued that federal taxes are (1) redistributed fairly to the states and (2) that federal expense benefit all states equally.

[18]indirect base multipliers are used to estimate the local jobs not related to the considered job source (here solar energy) but created indirectly by the new revenues emanating from the new [solar] jobs

[19] At the higher penetration levels the two approaches to consider would be regional (or continental) interconnection upgrade and smart coupling with natural gas generation and wind power generation – the cost of these approaches has not been quantified as part of this study.

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Appendix 3: Detailed Results

Pittsburgh

Table A4- 1. Technical results, Pittsburgh.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	475	475	475	475
Annual Energy Production (MWh)	716,621	631,434	595,373	892,905
Capacity Factor (%)	17%	15%	14%	21%
Generation Capacity (% of Fleet Capacity)	41%	43%	45%	48%
T&D Capacity (% of Fleet Capaccity)	31%	32%	32%	32%

Table A4- 2. Value ($/kW), Pittsburgh.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$813	$719	$678	$1,011
O&M Cost Savings	$396	$350	$331	$493
Total Energy Value	$1,209	$1,069	$1,009	$1,503
Strategic				
Security Enhancement Value	$446	$394	$372	$554
Long Term Societal Value	$557	$493	$465	$693
Total Strategic Value	$1,003	$887	$837	$1,247
Other				
Fuel Price Hedge Value	$613	$542	$512	$763
Generation Capacity Value	$432	$446	$468	$505
T&D Capacity Value	$127	$127	$130	$129
Market Price Reduction Value	$696	$718	$715	$740
Environmental Value	$1,064	$940	$888	$1,322
Economic Development Value	$870	$769	$726	$1,081
(Solar Penetration Cost)	($446)	($394)	($372)	($554)
Total Other Value	$3,355	$3,149	$3,067	$3,987
Total Value	**$5,568**	**$5,105**	**$4,913**	**$6,737**

Table A4- 3. Levelized Value ($/MWh), Pittsburgh.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$41	$41	$41
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$61	$61	$62	$61
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$28	$28	$28	$28
Total Strategic Value	$51	$51	$51	$51
Other				
Fuel Price Hedge Value	$31	$31	$31	$31
Generation Capacity Value	$22	$26	$29	$21
T&D Capacity Value	$6	$7	$8	$5
Market Price Reduction Value	$35	$41	$44	$30
Environmental Value	$54	$54	$54	$54
Economic Development Value	$44	$44	$44	$44
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$170	$181	$187	$162
Total Value	**$282**	**$293**	**$300**	**$274**

Figure A4- 1. Value ($/kW), Pittsburgh.

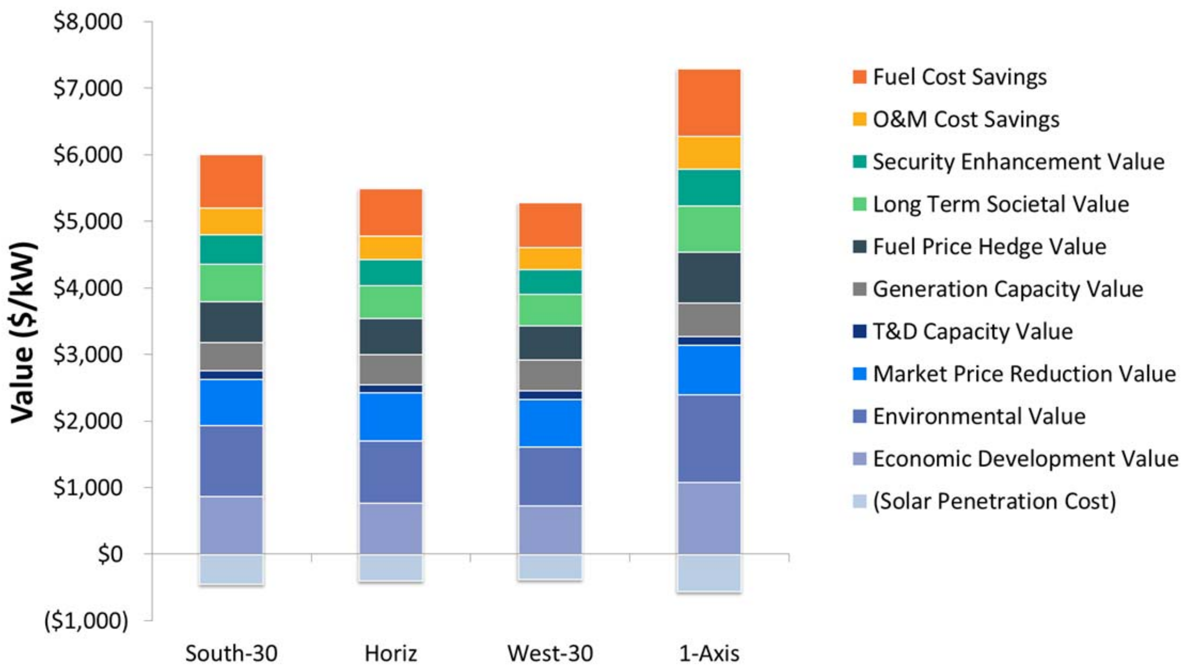
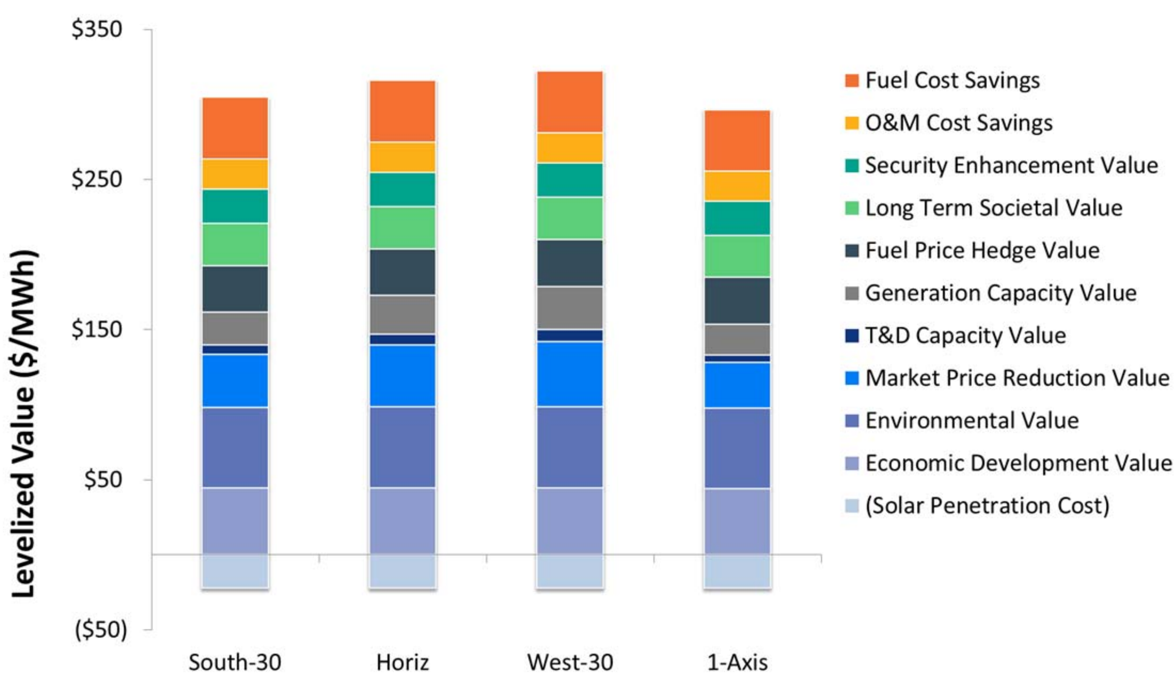


Figure A4- 2. Levelized Value ($/MWh), Pittsburgh.



Harrisburg[20]

Table A4- 4. Technical results, Harrisburg.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1129	1129	1129	1129
Annual Energy Production (MWh)	1,809,443	1,565,940	1,461,448	2,274,554
Capacity Factor (%)	18%	16%	15%	23%
Generation Capacity (% of Fleet Capacity)	28%	27%	26%	32%
T&D Capacity (% of Fleet Capaccity)	14%	14%	14%	14%

Table A4- 5. Value results ($/kW), Harrisburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$751	$652	$608	$942
O&M Cost Savings	$366	$318	$296	$459
Total Energy Value	$1,117	$969	$904	$1,401
Strategic				
Security Enhancement Value	$424	$368	$343	$532
Long Term Societal Value	$530	$460	$429	$665
Total Strategic Value	$954	$827	$772	$1,196
Other				
Fuel Price Hedge Value	$786	$682	$636	$985
Generation Capacity Value	$297	$287	$274	$336
T&D Capacity Value	$24	$24	$24	$24
Market Price Reduction Value	$1,241	$1,224	$1,171	$1,335
Environmental Value	$1,011	$877	$819	$1,268
Economic Development Value	$827	$717	$669	$1,037
(Solar Penetration Cost)	($424)	($368)	($343)	($532)
Total Other Value	$3,761	$3,444	$3,249	$4,454
Total Value	**$5,832**	**$5,240**	**$4,925**	**$7,051**

[20] Scranton and Harrisburg constitute two examples of a 15% penetration within PPL territory. Strictly speaking this does not amount to a 30% penetration, but two examples of 15% grid penetration where resource would be deployed in either location, illustrating how results are influenced by the location choice, everything else (utility and economic assumptions) being equal.

Table A4- 6. Levelized Value results ($/MWh), Harrisburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$41	$41	$40
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$60	$61	$60	$60
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$29	$29	$29	$29
Total Strategic Value	$52	$52	$52	$51
Other				
Fuel Price Hedge Value	$42	$43	$43	$42
Generation Capacity Value	$16	$18	$18	$14
T&D Capacity Value	$1	$1	$2	$1
Market Price Reduction Value	$67	$76	$78	$57
Environmental Value	$55	$55	$55	$55
Economic Development Value	$45	$45	$45	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$203	$215	$217	$191
Total Value	**$315**	**$327**	**$330**	**$303**

Figure A4- 3. Value ($/kW), Harrisburg.

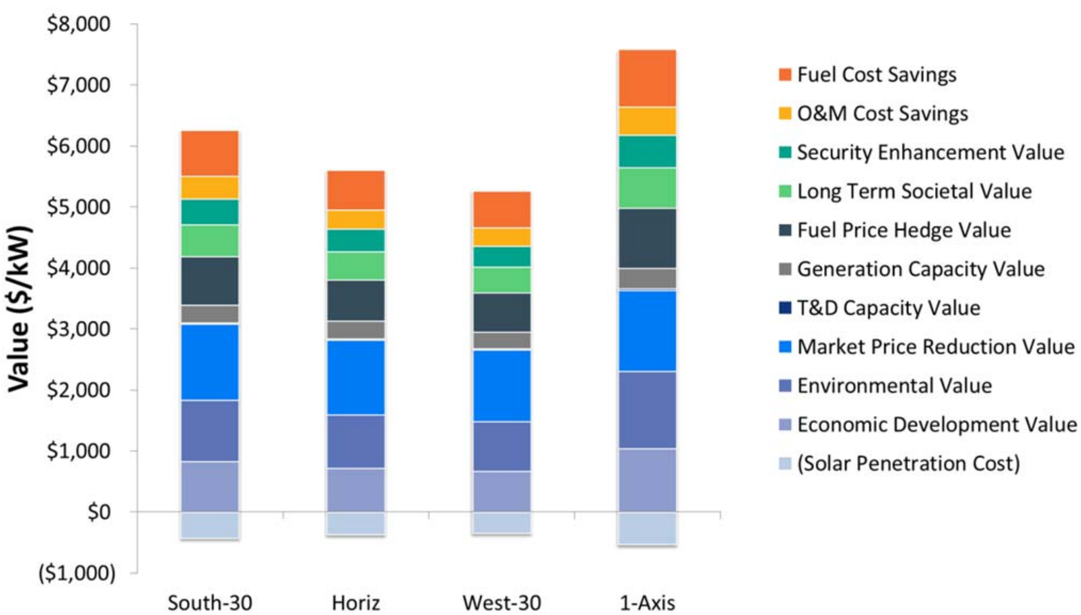
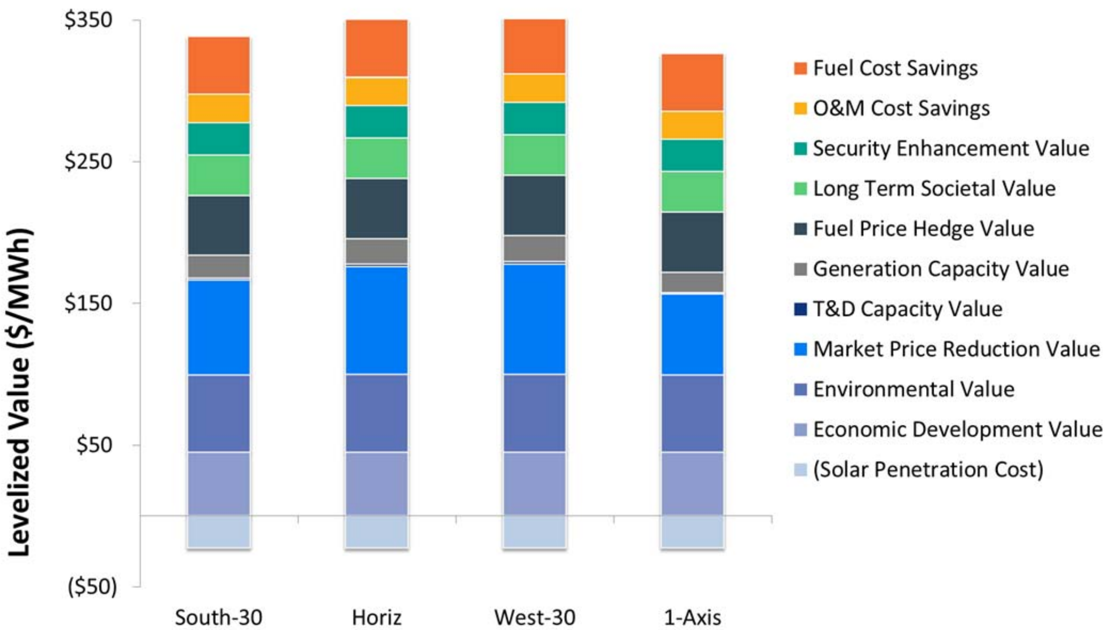


Figure A4- 4. Levelized Value ($/MWh), Harrisburg.



Scranton

Table A4- 7. Technical results, Scranton.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1129	1129	1129	1129
Annual Energy Production (MWh)	1,698,897	1,479,261	1,386,699	2,123,833
Capacity Factor (%)	17%	15%	14%	21%
Generation Capacity (% of Fleet Capacity)	28%	27%	26%	32%
T&D Capacity (% of Fleet Capaccity)	14%	14%	14%	14%

Table A4- 8. Value ($/kW), Scranton.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$706	$616	$577	$880
O&M Cost Savings	$344	$300	$281	$429
Total Energy Value	$1,050	$916	$859	$1,309
Strategic				
Security Enhancement Value	$398	$348	$326	$497
Long Term Societal Value	$498	$435	$407	$621
Total Strategic Value	$896	$782	$733	$1,118
Other				
Fuel Price Hedge Value	$738	$644	$604	$921
Generation Capacity Value	$290	$283	$276	$336
T&D Capacity Value	$24	$24	$24	$24
Market Price Reduction Value	$1,206	$1,193	$1,157	$1,311
Environmental Value	$950	$829	$777	$1,185
Economic Development Value	$777	$678	$636	$969
(Solar Penetration Cost)	($398)	($348)	($326)	($497)
Total Other Value	$3,586	$3,303	$3,148	$4,249
Total Value	**$5,532**	**$5,001**	**$4,740**	**$6,676**

Table A4- 9. Levelized Value ($/MWh), Scranton.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$41	$41	$41
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$60	$61	$61	$60
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$29	$29	$29	$29
Total Strategic Value	$52	$52	$52	$51
Other				
Fuel Price Hedge Value	$42	$43	$43	$42
Generation Capacity Value	$17	$19	$19	$15
T&D Capacity Value	$1	$2	$2	$1
Market Price Reduction Value	$69	$79	$82	$60
Environmental Value	$55	$55	$55	$55
Economic Development Value	$45	$45	$45	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$206	$218	$222	$196
Total Value	**$318**	**$331**	**$334**	**$307**

Figure A4- 5. Value ($/kW), Scranton.

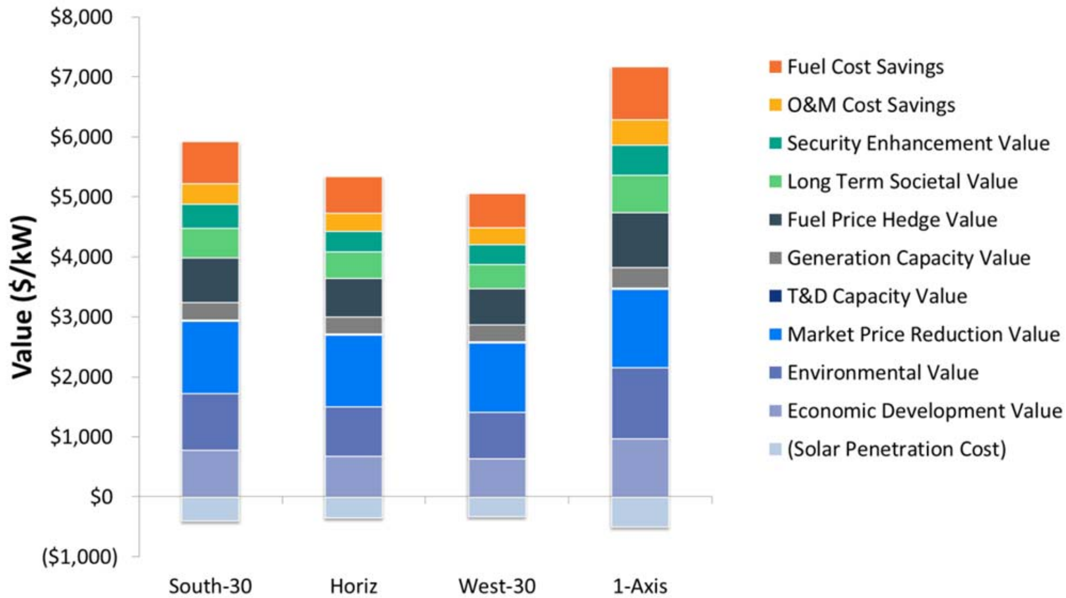
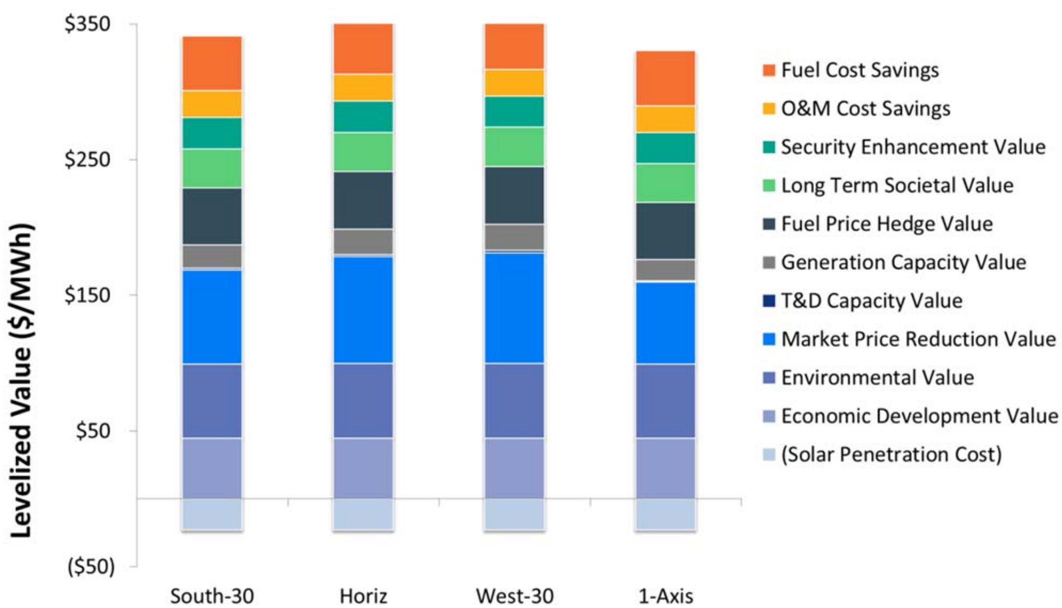


Figure A4- 6. Levelized Value ($/MWh), Scranton.



Philadelphia

Table A4- 10. Technical results, Philadelphia.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1348	1348	1348	1348
Annual Energy Production (MWh)	2,339,424	1,991,109	1,847,394	2,943,101
Capacity Factor (%)	20%	17%	16%	25%
Generation Capacity (% of Fleet Capacity)	38%	40%	43%	46%
T&D Capacity (% of Fleet Capaccity)	21%	21%	21%	21%

Table A4- 11. Value results ($/kW), Philadelphia.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$706	$602	$559	$886
O&M Cost Savings	$344	$294	$273	$432
Total Energy Value	$1,049	$896	$832	$1,318
Strategic				
Security Enhancement Value	$405	$346	$321	$509
Long Term Societal Value	$507	$432	$402	$636
Total Strategic Value	$912	$778	$723	$1,145
Other				
Fuel Price Hedge Value	$876	$747	$694	$1,100
Generation Capacity Value	$401	$418	$452	$483
T&D Capacity Value	$65	$65	$65	$65
Market Price Reduction Value	$1,013	$1,027	$1,018	$1,103
Environmental Value	$967	$825	$766	$1,214
Economic Development Value	$790	$675	$626	$993
(Solar Penetration Cost)	($405)	($346)	($321)	($509)
Total Other Value	$3,706	$3,412	$3,300	$4,449
Total Value	**$5,667**	**$5,086**	**$4,855**	**$6,912**

Table A4- 12. Levelized Value results ($/MWh), Philadelphia.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$38	$38	$38	$38
O&M Cost Savings	$18	$19	$19	$18
Total Energy Value	$56	$57	$57	$56
Strategic				
Security Enhancement Value	$22	$22	$22	$22
Long Term Societal Value	$27	$27	$27	$27
Total Strategic Value	$49	$49	$49	$49
Other				
Fuel Price Hedge Value	$47	$47	$47	$47
Generation Capacity Value	$22	$26	$31	$21
T&D Capacity Value	$3	$4	$4	$3
Market Price Reduction Value	$54	$65	$69	$47
Environmental Value	$52	$52	$52	$52
Economic Development Value	$42	$43	$43	$42
(Solar Penetration Cost)	($22)	($22)	($22)	($22)
Total Other Value	$199	$215	$224	$190
Total Value	**$304**	**$321**	**$330**	**$295**

Figure A4- 7. Value ($/kW), Philadelphia.

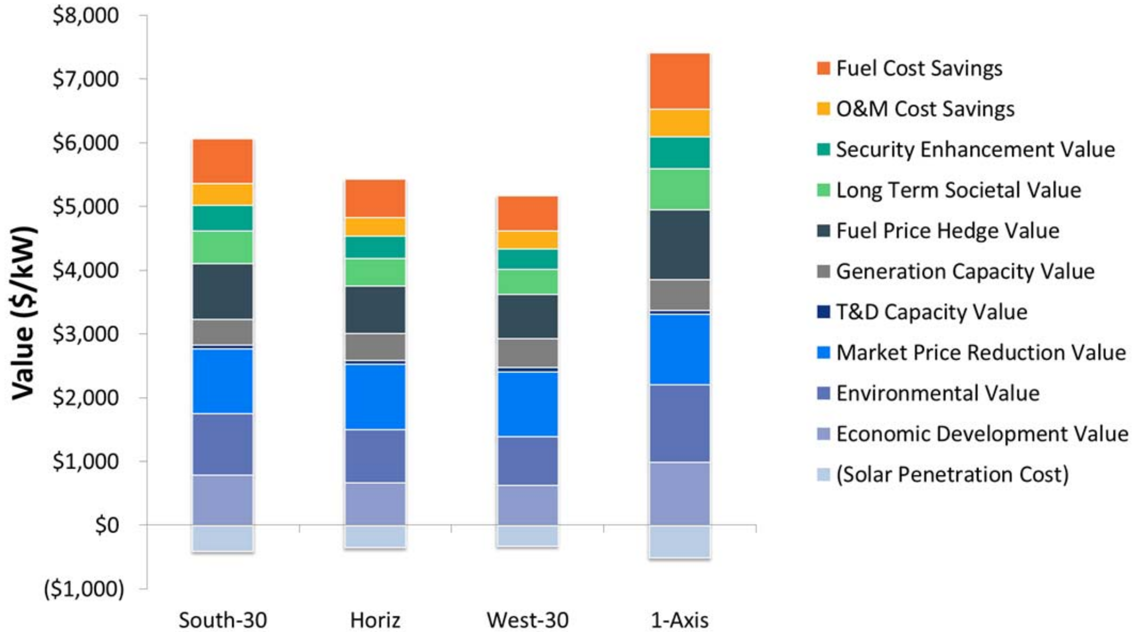
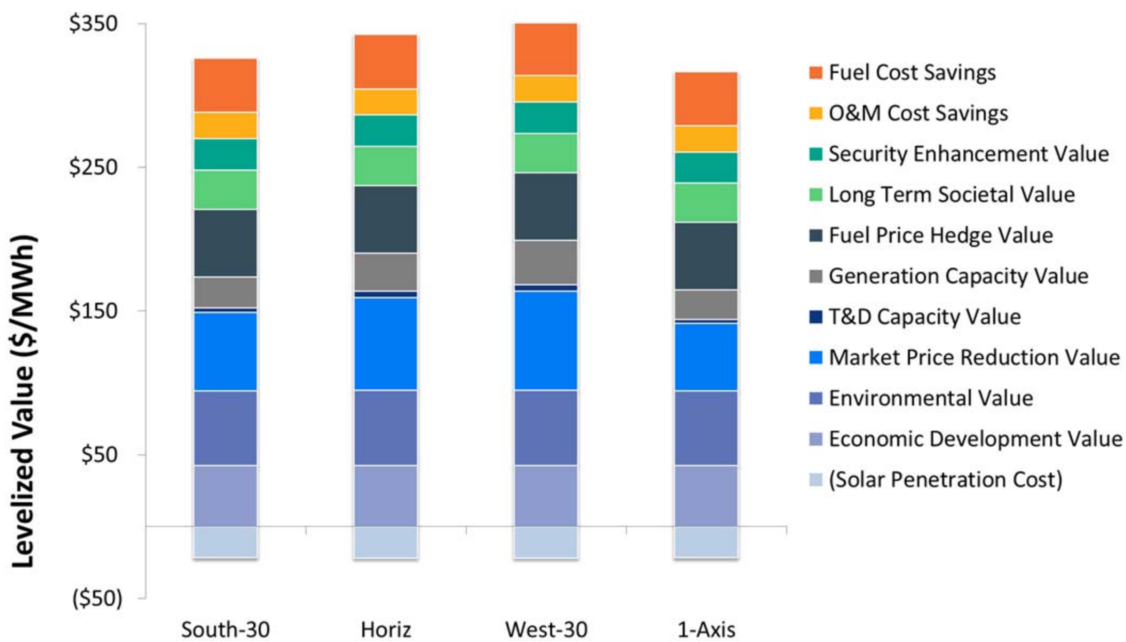


Figure A4- 8. Levelized Value ($/MWh), Philadelphia.



Jamesburg

Table A4- 13. Technical results, Jamesburg.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	991	991	991	991
Annual Energy Production (MWh)	1,675,189	1,431,899	1,315,032	2,102,499
Capacity Factor (%)	19%	16%	15%	24%
Generation Capacity (% of Fleet Capacity)	45%	47%	51%	52%
T&D Capacity (% of Fleet Capaccity)	29%	31%	29%	26%

Table A4- 14. Value results ($/kW), Jamesburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$1,020	$878	$808	$1,276
O&M Cost Savings	$497	$428	$394	$622
Total Energy Value	$1,517	$1,306	$1,203	$1,898
Strategic				
Security Enhancement Value	$549	$472	$435	$686
Long Term Societal Value	$686	$590	$544	$858
Total Strategic Value	$1,234	$1,062	$978	$1,544
Other				
Fuel Price Hedge Value	$586	$504	$465	$733
Generation Capacity Value	$468	$496	$531	$546
T&D Capacity Value	$23	$25	$23	$21
Market Price Reduction Value	$1,266	$1,306	$1,315	$1,363
Environmental Value	$560	$482	$444	$700
Economic Development Value	$1,097	$944	$870	$1,373
(Solar Penetration Cost)	($549)	($472)	($435)	($686)
Total Other Value	$3,451	$3,285	$3,212	$4,050
Total Value	**$6,202**	**$5,653**	**$5,393**	**$7,492**

Table A4- 15. Levelized Value results ($/MWh), Jamesburg.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$42	$42	$43	$42
O&M Cost Savings	$21	$21	$21	$21
Total Energy Value	$63	$63	$63	$63
Strategic				
Security Enhancement Value	$23	$23	$23	$23
Long Term Societal Value	$28	$29	$29	$28
Total Strategic Value	$51	$51	$52	$51
Other				
Fuel Price Hedge Value	$24	$24	$24	$24
Generation Capacity Value	$19	$24	$28	$18
T&D Capacity Value	$1	$1	$1	$1
Market Price Reduction Value	$52	$63	$69	$45
Environmental Value	$23	$23	$23	$23
Economic Development Value	$45	$46	$46	$45
(Solar Penetration Cost)	($23)	($23)	($23)	($23)
Total Other Value	$143	$159	$169	$134
Total Value	**$257**	**$274**	**$284**	**$247**

Figure A4- 9. Value ($/kW), Jamesburg.

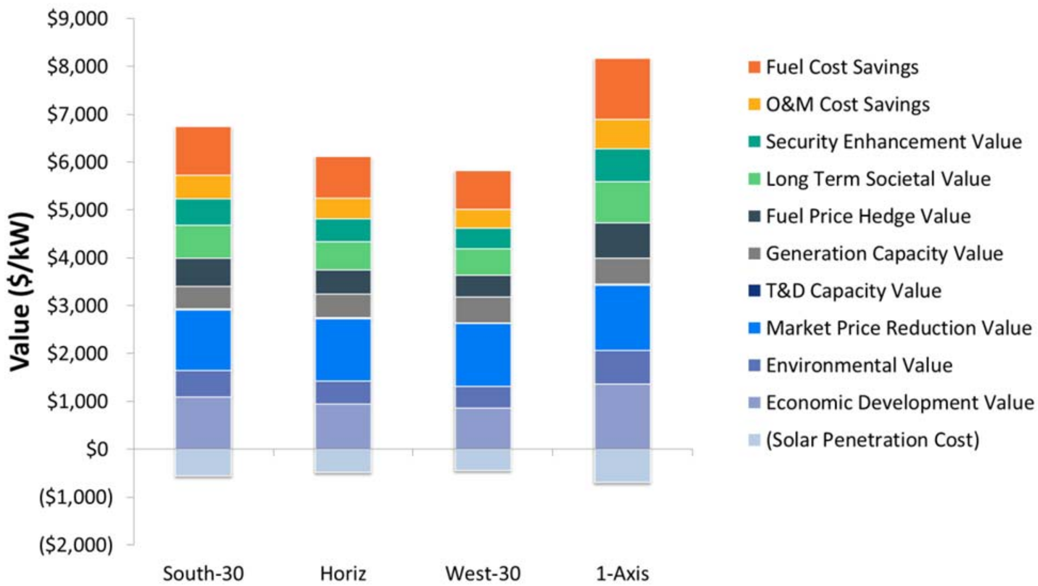
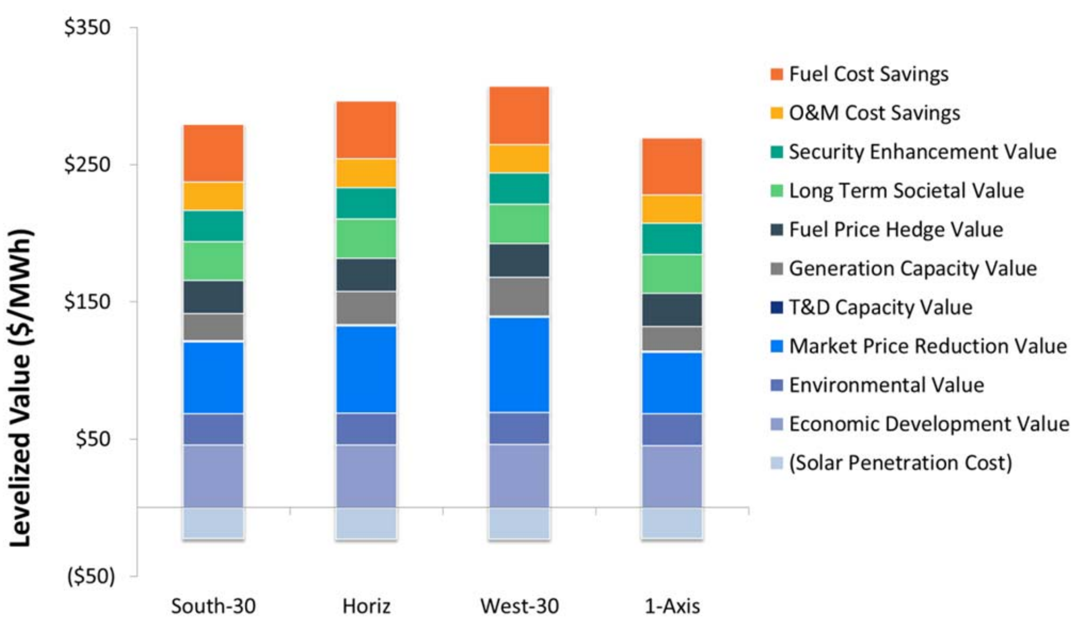


Figure A4- 10. Levelized Value ($/MWh), Jamesburg.



Newark

Table A4- 16. Technical results, Newark.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	1640	1640	1640	1640
Annual Energy Production (MWh)	2,677,626	2,303,173	2,118,149	3,350,313
Capacity Factor (%)	19%	16%	15%	23%
Generation Capacity (% of Fleet Capacity)	45%	47%	51%	54%
T&D Capacity (% of Fleet Capaccity)	56%	57%	57%	57%

Table A4- 17. Value results ($/kW), Newark.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$709	$612	$564	$885
O&M Cost Savings	$345	$298	$275	$431
Total Energy Value	$1,054	$911	$839	$1,317
Strategic				
Security Enhancement Value	$403	$348	$321	$503
Long Term Societal Value	$504	$435	$401	$629
Total Strategic Value	$907	$783	$721	$1,132
Other				
Fuel Price Hedge Value	$798	$689	$635	$996
Generation Capacity Value	$470	$489	$534	$568
T&D Capacity Value	$147	$151	$151	$151
Market Price Reduction Value	$927	$959	$958	$989
Environmental Value	$411	$355	$327	$513
Economic Development Value	$806	$696	$641	$1,007
(Solar Penetration Cost)	($403)	($348)	($321)	($503)
Total Other Value	$3,156	$2,991	$2,926	$3,721
Total Value	**$5,117**	**$4,685**	**$4,486**	**$6,170**

Table A4- 18. Levelized Value results ($/MWh), Newark.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$39	$39	$39	$39
O&M Cost Savings	$19	$19	$19	$19
Total Energy Value	$58	$58	$58	$58
Strategic				
Security Enhancement Value	$22	$22	$22	$22
Long Term Societal Value	$28	$28	$28	$28
Total Strategic Value	$50	$50	$50	$50
Other				
Fuel Price Hedge Value	$44	$44	$44	$44
Generation Capacity Value	$26	$31	$37	$25
T&D Capacity Value	$8	$10	$10	$7
Market Price Reduction Value	$51	$61	$66	$43
Environmental Value	$22	$23	$23	$22
Economic Development Value	$44	$44	$44	$44
(Solar Penetration Cost)	($22)	($22)	($22)	($22)
Total Other Value	$173	$190	$202	$163
Total Value	**$280**	**$298**	**$310**	**$270**

Figure A4- 11. Value ($/kW), Newark.

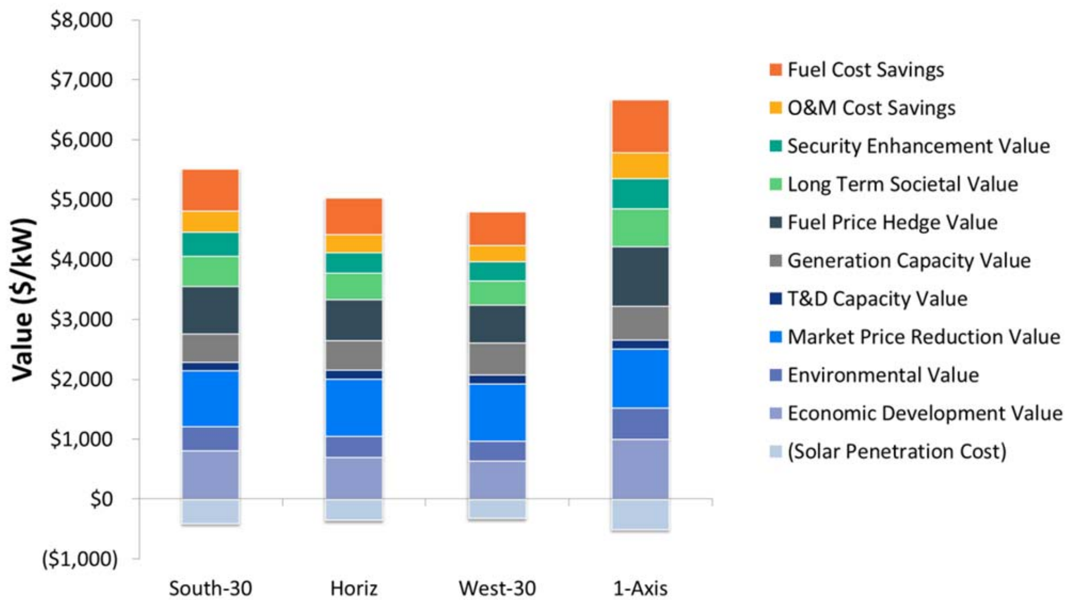
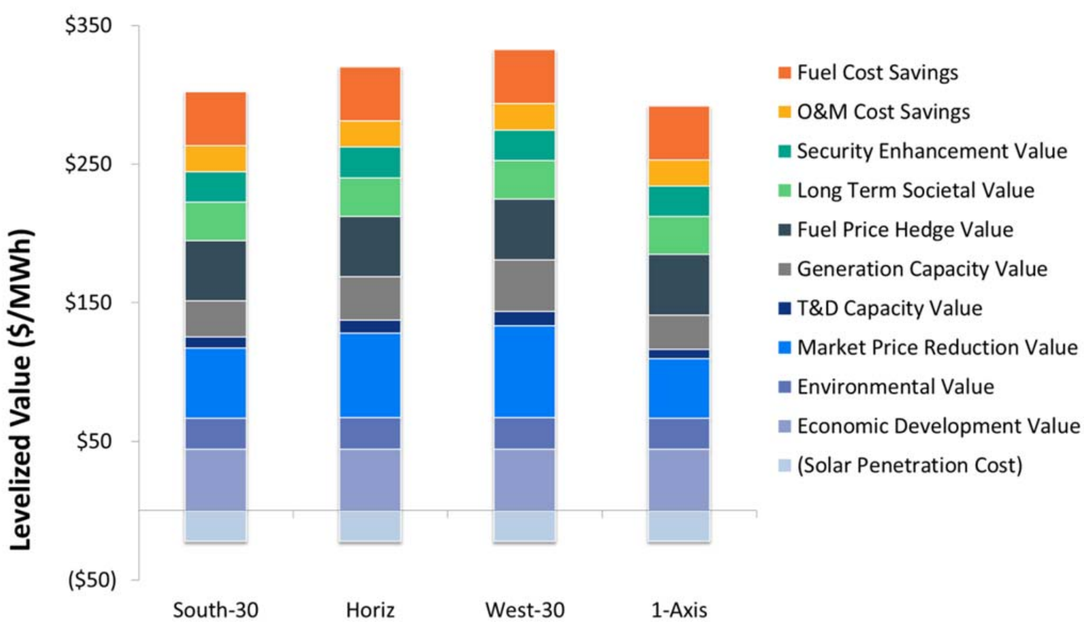


Figure A4- 12. Levelized Value ($/MWh), Newark.



Atlantic City

Table A4- 19. Technical results, Atlantic City.

	South-30	Horiz	West-30	1-Axis
Fleet Capacity (MWac)	443	443	443	443
Annual Energy Production (MWh)	827,924	705,374	654,811	1,039,217
Capacity Factor (%)	21%	18%	17%	27%
Generation Capacity (% of Fleet Capacity)	46%	48%	54%	57%
T&D Capacity (% of Fleet Capaccity)	36%	37%	38%	36%

Table A4- 20. Value results ($/kW), Atlantic City.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$1,081	$927	$863	$1,354
O&M Cost Savings	$527	$452	$421	$660
Total Energy Value	$1,609	$1,380	$1,283	$2,015
Strategic				
Security Enhancement Value	$584	$501	$466	$732
Long Term Societal Value	$730	$626	$582	$914
Total Strategic Value	$1,314	$1,127	$1,048	$1,646
Other				
Fuel Price Hedge Value	$662	$567	$528	$828
Generation Capacity Value	$478	$503	$569	$600
T&D Capacity Value	$49	$51	$52	$49
Market Price Reduction Value	$1,412	$1,485	$1,508	$1,503
Environmental Value	$596	$511	$475	$746
Economic Development Value	$1,168	$1,002	$932	$1,463
(Solar Penetration Cost)	($584)	($501)	($466)	($732)
Total Other Value	$3,781	$3,618	$3,598	$4,458
Total Value	**$6,704**	**$6,125**	**$5,929**	**$8,119**

Table A4- 21. Levelized Value results ($/MWh), Atlantic City.

	South-30	Horiz	West-30	1-Axis
Energy				
Fuel Cost Savings	$41	$42	$42	$41
O&M Cost Savings	$20	$20	$20	$20
Total Energy Value	$61	$62	$62	$61
Strategic				
Security Enhancement Value	$22	$22	$22	$22
Long Term Societal Value	$28	$28	$28	$28
Total Strategic Value	$50	$50	$51	$50
Other				
Fuel Price Hedge Value	$25	$25	$25	$25
Generation Capacity Value	$18	$23	$27	$18
T&D Capacity Value	$2	$2	$2	$1
Market Price Reduction Value	$54	$66	$73	$46
Environmental Value	$23	$23	$23	$23
Economic Development Value	$45	$45	$45	$44
(Solar Penetration Cost)	($22)	($22)	($22)	($22)
Total Other Value	$144	$162	$174	$135
Total Value	**$256**	**$274**	**$286**	**$247**

Figure A4- 13. Value ($/kW), Atlantic City.

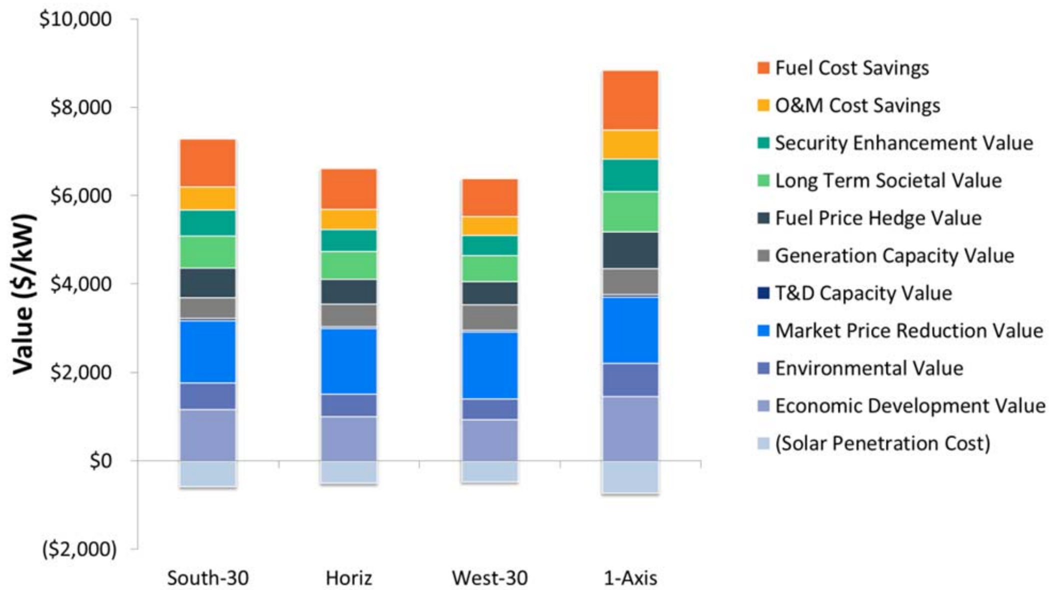
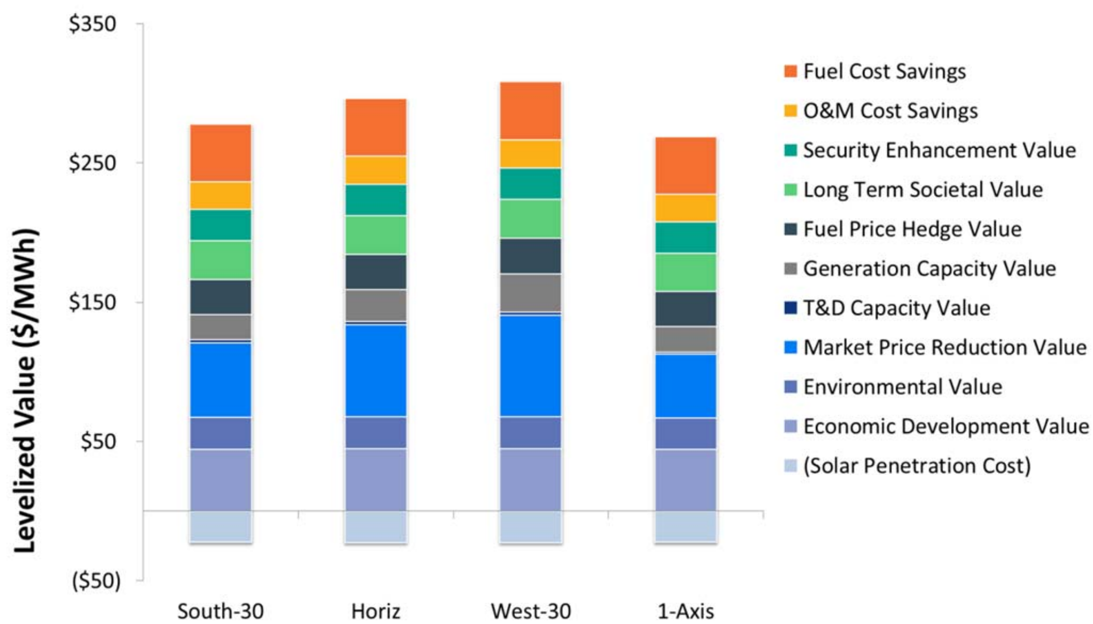


Figure A4- 14. Levelized Value ($/MWh), Atlantic City.



State of New Jersey
DIVISION OF RATE COUNSEL
140 EAST FRONT STREET, 4TH FL
P.O. BOX 003
TRENTON, NEW JERSEY 08625

STEFANIE A. BRAND
Director

January 16, 2020

By Hand Delivery and Electronic Mail
Honorable Aida Camacho-Welch, Secretary
NJ Board of Public Utilities
44 South Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, NJ 08625-0350

Re: Comments of the New Jersey Division of Rate Counsel on the Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps

Dear Secretary Camacho-Welch:

Please accept for filing the enclosed original and ten (10) copies of comments being submitted on behalf of the New Jersey Division of Rate Counsel ("Rate Counsel") in connection with the above-referenced matter. Copies of Rate Counsel's comments are being provided to all parties on the service list by electronic mail and hard copies will be provided upon request to our office.

We are enclosing one additional copy of the comments. **Please stamp and date the extra copy as "filed" and return to our courier.**

Tel: (609) 984-1460 • Fax: (609) 292-2923 • Fax: (609) 292-4991
http://www.nj.gov/rpa E-Mail: njratepayer@rpa.nj.gov

Thank you for our consideration and attention to this matter.

Respectfully submitted,

STEFANIE A. BRAND
Director, Division of Rate Counsel

By: Sarah H Steindel
Sarah H. Steindel, Esq.
Assistant Deputy Rate Counsel

Enclosure

cc: Charles.Gurkas@bpu.nj.gov
Paul E. Flanagan, BPU
Sara Bluhm, BPU
Kelly Mooij, BPU
Sherri Jones, BPU
Scott Hunter, BPU
Abe Silverman, BPU
Ariane Benrey, BPU
Ronald Jackson, BPU
Rachel Boylan, BPU
Pamela Owen, DAG, ASC

STATE OF NEW JERSEY

BEFORE THE BOARD OF PUBLIC UTILITIES

In re: Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps	)))

COMMENTS OF THE NEW JERSEY DIVISON OF RATE COUNSEL ON THE STAFF STRAW PROPOSAL ON DEFINING THE CLEAN ENERGY ACT OF 2018's STATUTORY COST CAPS

January 16, 2020

1. Introduction

The Division of Rate Counsel ("Rate Counsel") thanks the Board of Public Utilities ("Board" or "BPU") for the opportunity to provide comments on Staff's Straw Proposal to define the statutory cost caps ("cost caps") in the Clean Energy Act (P.L.2018, c.17) ("CEA"), which will guide the Board in its development of the solar market in New Jersey. The CEA directs the Board to transition the solar market away from current solar financing methods based on the use of Solar Renewable Energy Credits ("SRECs") to a new program that will continue the efficient and orderly development of solar energy generation. In addition, the CEA established a cost cap on the total cost that ratepayers are required to pay for Class I renewable energy requirements. Thus, as part of its adoption of the solar Transition Incentive program ("TI Program") on December 6, 2019, the Board directed Staff to "initiate a proceeding on the calculation of the cost cap, and to report back to the Board regarding the recommendations and outcomes of said proceeding[.]"

On January 6, 2020 the Board issued a Notice scheduling a stakeholder meeting on January 15, 2020, and soliciting written comments to consider three subject areas: (1) whether the Board should adopt a multi-year approach to compliance with Cost Cap; (2) how the Cost Caps should be determined and implemented; and (3) how the Legacy SREC program should be reformed to ensure a robust solar market while conforming to the statutory limitations on cost. Comments related to the first subject area are due on or before January 16, 2020 and comments related to the second and third objective are due on or before January 31, 2020. These comments address the questions issued for the first objective, which appear under the heading "Treatment of Cost Cap 'Headroom' in the Clean Energy Act" in the Board's Notice.

Treatment of Cost Cap "Headroom" in the Clean Energy Act

1. **Should the Board adopt a true-up banking methodology so that any expenditures above or below the Cost Cap in one Energy Year are carried forward to a subsequent year?**

Rate Counsel does not object to the use of a true-up mechanism to reconcile actual expenditures to the cost caps established in the CEA. Rate Counsel acknowledges that a true-up mechanism will be needed as a practical matter because actual expenditure will not be known until after the end of each energy year. However, the true-up mechanism should be administered within reasonable limits to maintain consistency with the intent of the CEA.

The CEA is clear in its definition of pre-determined, annual rate caps on Class I renewable energy costs. Also, the CEA clearly identifies cost cap percentages for specific energy years. For instance, the legislation provides that costs "shall not exceed nine percent of the total paid for electricity by all customers in the State for energy year 2019, energy year 2020, and energy year 2021, respectively...." N.J.S.A. 48:3-87 (emphasis supplied) The CEA says nothing about averaging across the EY2019 to EY2021 time period. It clearly limits the annual renewable energy costs in each energy year "respectively" – not "comprehensively" nor "collectively." The CEA reinforces this definition for later years by noting that renewable energy costs "shall not exceed seven percent of the total paid for electricity by all customers in the State in any energy year thereafter." Id. (emphasis supplied).

Accordingly, the Board should design and implement the solar transition with the objective of remaining within the cost caps for each energy year. The true-up mechanism should be used only as an administrative mechanism to provide for the inevitable variances between planned and actual expenditures.

2. Would allowing for banking between Energy Years affect the total ratepayer impact?

If used as described in Rate Counsel's response to Question 1 above, the impacts on total ratepayer impacts should be minimal.

3. Should the Board consider averaging costs over a period in order to more accurately reflect total compliance costs, while smoothing transient effects? How would such an average be constructed?

Averaging these costs across multiple years is inconsistent with the CEA. For the reasons explained in Rate Counsel's response to Question 1 above, the Board should not plan to spend in excess of the statutory cap for any energy year.

4. Should the Board adopt a true-up banking mechanism that can utilize unspent headroom from previous years as well as anticipated/projected headroom from future years?

For the reasons explained in Rate Counsel's response to Question 1 above, the Board should not design and implement the solar transition based on the planned transfer of "headroom" among energy years. The goal should be to administer the Program consistent with the caps, utilizing a true up mechanism at the end of each year to address any minor variations between energy years.

5. How should the accounting for such transfers be done?

See Rate Counsel's response to Questions 1, 2, 3, and 4 above.

State of New Jersey
DIVISION OF RATE COUNSEL
140 EAST FRONT STREET, 4TH FL
P.O. BOX 003
TRENTON, NEW JERSEY 08625

PHIL MURPHY
Governor

SHEILA OLIVER
Lt. Governor

STEFANIE A. BRAND
Director

January 31, 2020

By Hand Delivery and Electronic Mail
Honorable Aida Camacho-Welch, Secretary
NJ Board of Public Utilities
44 South Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, NJ 08625-0350

Re: Comments of the New Jersey Division of Rate Counsel on the Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps—Items 2 and 3

Dear Secretary Camacho-Welch:

Please accept for filing the enclosed original and ten (10) copies of comments being submitted on behalf of the New Jersey Division of Rate Counsel ("Rate Counsel") in connection with the above-referenced matter. Copies of Rate Counsel's comments are being provided to all parties on the service list by electronic mail and hard copies will be provided upon request to our office.

We are enclosing one additional copy of the comments. **Please stamp and date the extra copy as "filed" and return to our courier.**

Thank you for our consideration and attention to this matter.

Respectfully submitted,

STEFANIE A. BRAND
Director, Division of Rate Counsel

By: Sarah H. Steindel

Sarah H. Steindel, Esq.
Assistant Deputy Rate Counsel

Enclosure

cc: Charles.Gurkas@bpu.nj.gov
Paul E. Flanagan, BPU
Sara Bluhm, BPU
Kelly Mooij, BPU
Sherri Jones, BPU
Scott Hunter, BPU
Abe Silverman, BPU
Ariane Benrey, BPU
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Pamela Owen, DAG, ASC

STATE OF NEW JERSEY

BEFORE THE BOARD OF PUBLIC UTILITIES

In re: Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps	)))

COMMENTS OF THE NEW JERSEY DIVISION OF RATE COUNSEL ON THE STAFF STRAW PROPOSAL ON DEFINING THE CLEAN ENERGY ACT OF 2018's STATUTORY COST CAPS

January 31, 2020

1. **Introduction**

The Division of Rate Counsel ("Rate Counsel") thanks the Board of Public Utilities ("Board" or "BPU") for the opportunity to provide comments on its Staff's Straw Proposal to define the statutory cost caps ("cost caps") in the Clean Energy Act (P.L.2018, c.17) ("CEA"), which will guide the Board in its development of the solar market in New Jersey. The CEA directs the Board to transition the solar market away from current solar financing methods based on the use of Solar Renewable Energy Credits ("SRECs") to a new program that will continue the efficient and orderly development of solar energy generation. In addition, the CEA established a cost cap on the total cost that ratepayers are required to pay for Class I renewable energy requirements. Thus, as part of its adoption of the solar Transition Incentive program ("TI Program") on December 6, 2019, the Board directed its Staff to "initiate a proceeding on the calculation of the cost cap, and to report back to the Board regarding the recommendations and outcomes of said proceeding ...."[1]

In response to this directive, Staff, by Notice dated December 6, 2019, initiated a proceeding to solicit comments on three objectives: (1) determine whether the Board should adopt a multi-year approach to compliance with Cost Caps; (2) gather stakeholder input as to how the Cost Caps should be determined and implemented; and (3) explore reforms to the Legacy SREC program that ensure a robust solar market while conforming to the statutory limitations on cost. Notice at 1. Rate Counsel filed comments on the first issue on January 16, 2020. The comments herein address the questions issued for the second objective, "Defining the Terms of the Clean Energy Act;" and the third objective "Reform of the Legacy SREC Program."

[1] I/M/O a New Jersey Solar Transition Pursuant to P.L. 2018, c. 17, BPU Dkt. No. QO19010068, Order at 34 (Dec. 6, 2020).

Defining the Terms of the Clean Energy Act

1. Do parties agree that Staff has correctly identified the numerator and the denominator?

Response:

Rate Counsel is unable to respond adequately to this question because Staff has not explicitly provided nor defined how the numerator and denominator for the cost cap calculation will be developed. Staff simply defines the numerator as the "Cost to Customers of the Class I Renewable Energy Requirement." Similarly, the denominator is defined as the "Total Paid for Electricity by All Customers in the State." While Staff has correctly quoted the statutory language, it has not identified the components of Class I Costs or the components of Total Paid for Electricity that it proposes to use in making the calculations. Further, Staff has not identified the data sources it will use to make the calculations. Staff has also not identified when such calculations will be made and how they will be posted or communicated to the Board and stakeholders. Rate Counsel encourages Staff to explicitly define how it proposes to calculate the cost cap and the data upon which this calculation will be based.

2. Staff notes that the State's Class I REC programs have resulted in benefits to the citizens of the State of New Jersey, including improved public health, reduction in carbon emissions, and direct financial benefits, such as lower energy and capacity costs.

a. Is it appropriate for the Board to factor these benefits into the Cost Cap Equation?

Response:

No. It is not appropriate for the Board to factor any societal or financial benefits into the Cost Cap Equation. First, and most importantly, the Clean Energy Act does not allow the offsetting of benefits as suggested in this question. The statutory language quoted above sets a cap on "costs," and does not contain any language allowing the Board to subtract "qualitative and quantitative" benefits. Under the interpretation suggested by Staff's question, ratepayers could be required to pay for the "quantitative and qualitative value" of renewable energy plus additional subsidies amounting to nine percent of the total costs of electricity through energy year 2021 and seven percent thereafter. This would be an unreasonable result which clearly was not intended by the Legislature. Adding benefits to the cost cap calculation would only serve to allow increased ratepayer spending, which would be contrary to the statutory language and would undermine the CEA's objective of "continually reduc[ing]" ratepayer' renewable energy costs. N.J.S.A. 48:3-87(d)(3).

Second, improved public health and reduced carbon emissions are societal benefits that are exceedingly difficult to quantify. There is a wide variation in published estimates of societal benefits. These variations are a function of differences in studies, methodologies and assumptions employed, discount rates and damage functions. More importantly, the Board has recognized problems with the use of societal costs and benefits in the past. [2] The Board has not only noted the technical concerns with utilizing societal benefit estimates but has also addressed the inherent policy concern with their use, finding that, "environmental benefits should be tied to market prices because that is a reasonable manner to ensure fair, just and reasonable ratepayer impact." [3]

b. If so, please comment on which categories of benefits, if any should be included, whether they should be included in the numerator or denominator, and how they should be calculated.

Response:

None, for the reasons articulated in Rate Counsel's response to Question 2(a).

3. The numerator is defined as the "cost to customers of the Class I Renewable energy requirement."

Response:

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[2] I/M/O the Petition of Fishermen's Atlantic City Wind Farm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates, BPU Dkt. No. EO11050314V, Board Decision on the Merits of the Application at 23-24 (Mar. 28, 2014).

[3] Id. at 24.

This statement accurately quotes the statutory language, but Staff has not provided any clarity on how it will calculate this variable nor the data it will use to calculate this variable. Staff has also not explained how frequently this number will be calculated and made available to the public. Please see Rate Counsel's response to Question 1.

4. **Staff's current practice in calculating clean energy program costs is to aggregate retired quantities from the annual RPS compliance reports of load serving entities and apply the last price recorded in PJM-EIS Generation Attribute Tracking System ("GATS").**

a. Is there a better source of data and calculation methodology?

Response:

Rate Counsel is in agreement with Staff's current practice in calculating clean energy costs. Rate Counsel is not aware of a better source of data and/or a calculation methodology. The calculation should be consistent with the current practice of using the annual RPS compliance reports and prices from PJM GATS. Staff has provided no rationale for changing this methodology.

b. If so, how would we measure those costs?

Response:

Please see Rate Counsel's response to Question 4(a).

c. Should the Board analyze what energy costs would have been without the Cost Cap-Eligible Programs to determine the appropriate net cost to consumers of the programs?

Response:

No. Staff should not make this calculation since it is not relevant. Such a calculation should not be used to calculate any kind of offsetting benefit in the cost cap calculation. Such an offset would be contrary to the intent of the CEA for the reasons explained in Rate Counsel's response to Question 2(a).

d. If so, how should such an analysis be conducted?

This calculation should not be conducted since it is not relevant to estimating a cost cap consistent with clear legislative intent and language of the CEA.

e. How should Staff handle savings associated with the "merit order effect" whereby renewable energy and load reductions reduce the market price of capacity and energy rates to all customers?

Please see Rate Counsel's response to Question 2(d) above. Staff should not calculate merit order benefits since these benefits are not prescribed in the CEA. The CEA does not define a "net benefits" test of any kind nor does it use a net benefit-type variable in the calculation of the overall rate impact. Staff's proposal to estimate merit order benefits is inconsistent with past Board policies regarding the examination of net benefits for other renewables (i.e., offshore wind). In the past, the Board has clearly noted that these kinds of merit order benefits should not be included in a cost-benefit analysis.[4]

In addition, allowing for this type of benefit to be considered could influence the outcomes of competitive, FERC-regulated wholesale markets and would run contrary to a Supreme Court decision in Hughes v. Talen Energy Marketing, LLC,[5] which invalidated the State of Maryland's program that guaranteed independent power producers a long-term contract rate that differed from the PJM market clearing price for capacity because it interfered with the Federal Energy Regulatory Commission's ("FERC's) exclusive jurisdiction over wholesale electric rates. The decision of the United States District Court for the District of New Jersey decision in PPL EnergyPlus, LLC v. Hanna[6] invalidated the New Jersey Long Term Capacity

[4] I/M/O Consideration of the State Water Wind Project and Offshore Wind Renewable Energy Certificate. BPU Dkt. No. QO18080843, Order at 13 (Dec. 18, 2018).
[5] 578 U.S. __, 136 S. Ct. 1288, 194 L. Ed. 414 (1916)
[6] 977 F.Supp.2d 372 (D.N.J. 2013), aff'd PPL EnergyPlus, LLC v. Solomon, 766 F. 3d 241 (3d Cir. 2014).

Pilot Project ("LCAPP") on similar grounds.[7] If an explicitly stated intent of the New Jersey program is to reduce PJM market prices, the program could be pre-empted.

Please also refer to Rate Counsel's response to Question 2(a).

f. How should savings received by customers who install on-site renewable energy be addressed?

Response:

Customer savings do not need to be identified and addressed in the cost cap calculation since this is not prescribed in the CEA. Further, customer savings will be included as part of the overall, state level "total cost of retail electricity" sales noted earlier. The greater the energy savings, the lower the total cost of retail electricity (i.e., denominator) holding other factors constant, and assuming the Staff utilizes an appropriate measure of the retail cost of electricity from a credible and respected source, such as the Department of Energy, Energy Information Administration ("EIA") retail rate and electricity sales data.

g. Are there volatility hedge benefits that should be included?

Response:

No. It is not appropriate to incorporate any savings associated with a volatility hedge benefit in the Cost Cap Equation. Not only is this another assumed savings that is difficult to accurately quantify, but it also runs contrary to the legislative language and intent of the CEA. Further, as noted above, including such benefits is counter to the Board's past position in examining the value of other renewable energy resources. As the Board has noted, most ratepayers in New Jersey obtain electric supply through BGS auctions or third-party suppliers,

[7] See Cassell, B., Federal court knocks down a second state generation law, Transmission Hub (Oct. 14, 2013). Available at: https://www.transmissionhub.com/articles/2013/10/federal-court-knocks-down-a-second-state-generation-law.html.

and are thus not subject to frequent or severe volatility in energy prices thus this type of benefit is unwarranted.[8] Please see Rate Counsel's response to Question 2(a).

5. The denominator of the Cost Cap Equation references "total paid for electricity by all customers in the state."

a. Should payments associated with solar installations be included in the denominator? Should the Board differentiate between host-owned and third-party owned systems?
b. Are there other types of customer-generated electricity whose costs should be considered? For example, should the Board include electricity costs incurred by owners of Combined Heat & Power systems, microgrids, or other large on-site generators?
c. Should associated finance costs be included?
d. Should delivery charges imposed by the Electric Distribution Companies ("EDCs") be included?
e. Should Staff calculate the costs just to Board-jurisdictional load, as is the case for RPS compliance currently?

Response (Questions 5(a)-(e)):

Each of Staff's questions regarding the denominator of the Cost Cap Equation only serve to increase the denominator, and thereby increase ratepayer spending. There is absolutely no reason why payments associated with solar installations, finance costs, adjustments to jurisdictional load should be included in the straight-forward and simple calculation contemplated in the CEA. "Total paid for electricity" should be just that, the dollar amount spent on electricity by New Jersey customers. There is no valid rationale provided for including expenses to inflate the denominator. Lastly, the Board is unable to accurately determine the total cost of solar installations since it does not regulate these costs, the information associated with these costs is not collected by any government agency, nor is such cost information publicly available. This would raise considerable and unnecessary credibility and transparency issues in the calculation of the cost cap.

f. Should Staff calculate the costs as the sum of all EDC sales to end-use customers?

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[8] I/M/O Consideration of the State Water Wind Project and Offshore Wind Renewable Energy Certificate. BPU Dkt. No. QO18080843, Order at 14 (Dec. 18, 2018).

Response:

Yes. The cost should be calculated as the sum of electricity sales to end-use customers.

g. Should we rely on Energy Information Administration ("EIA") sales data?

Response:

Yes. The EIA would be a reasonable and reliable source for sales data.

h. Is there a better source of data and calculation methodology?

Response:

Rate Counsel is not aware of another source of data or calculation methodology.

i. How should the lag in EIA data be addressed?

Response:

EIA data on state electricity sales is published monthly and is only lagged by 2 months. This is not a major issue, and Staff could easily project two months of data using recent trends.

j. Should non-bypassable surcharges, including such things as Zero Emission Credits, be included in our calculation of energy costs?

Response:

Yes. Board approved non-bypassable charges should be included. However, Staff should recognize that such non-bypassable charges are included in the total retail electricity sales information collected by the EIA.[9]

Reform of the Legacy SREC Program

1. Should Staff consider reforms to the SREC market in order to reduce the variability in potential SREC outcomes?

Response:

[9] See U.S. Energy Information Administration, Annual Electric Power Industry Report, Form EIA-861 detailed data files, available at: https://www.eia.gov/electricity/data/eia861/.

Yes. Rate Counsel renews its position that Staff and the Board should restructure the New Jersey solar market in a manner that is consistent with the legislative intent of the CEA which calls for a mechanism that will be "efficient" and "orderly" and "continually reduce" the cost of achieving solar energy goals. The legacy SREC program has over-subsidized solar installations in New Jersey for too long and should be reformed.

2. **Should owners of SREC contracts be required to take part in any restructuring of the program, or should participation be voluntary?**

Response:

Participation in restructuring of the program should be mandatory for all owners of SREC contracts.

3. **Should Staff examine moving toward converting SRECs to a fixed price product, or would it be better to look at a lower Alternative Compliance Payment ("ACP") and the institution of a floor price or buyer of last resort?**

Response:

The legacy SREC program should be restructured to convert SRECs to a fixed price product. This would help to: (a) reduce overall ratepayer costs; (b) maintain some form of consistency between the legacy and transition programs; and (c) reduce uncertainty and potential volatility for the projects that remain in the legacy SREC program.

4. **If Staff were to recommend setting a fixed price for SRECs, how should that price be set?**

Response:

Throughout the development of the Transition Incentive program, Staff's consultants solicited information from the solar industry on installation costs and required returns. The responses received should provide enough information to estimate a fixed SREC price for the solar installations remaining in the legacy program.

5. If Staff were to look at a lower ACP and buyer of last resort program, how should such a program be structured?

Response:

Rate Counsel does not agree with and opposes continued use of an ACP and buyer of last resort program. Please see Rate Counsels' response to Question 3.

6. Should the Board consider a "tight collar"? How would such a program be implemented?

Response:

As noted in the Staff's proposal, a "tight collar" would constrain legacy SREC values so that they would remain within a certain range of prices. In Staff's terms, it would "protect investors" from low SREC costs in the same manner as ratepayers are supposed to be protected from high subsidy costs by the CEA cost cap. Rate Counsel disagrees with the continued manipulation of SREC prices for the legacy program and any mechanism that ties prices to an ACP. Please see Rate Counsel response to Question 5.

7. Are there other reforms that Staff should consider?

Response:

Rate Counsel is not aware of other reforms to be considered at this time.

New Jersey Resources

January 31, 2020

Via Electronic Submittal: Charles.Gurkas@bpu.nj.gov

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 Clinton Avenue, 9th Floor
Trenton, New Jersey 086258-0350

Re: Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps (Item#2: Cost Cap Calculations and Item #3: Legacy Projects)

Dear Ms. Camacho-Welch:

NJR Clean Energy Ventures ("NJRCEV") appreciates the opportunity to comment on the Staff Straw Proposal (the "Proposal") regarding how cost caps should be determined and addressing reforms to the legacy SREC program.

As a market leader, NJRCEV has invested almost $850 million since 2010 in nearly 300 MW of projects in the New Jersey solar market, which will generate almost 400,000 SRECs per year. Our commitment to the New Jersey solar market reflects our commitment to sustainability and the State's clean energy goals. New Jersey Resources Corporation, our parent company, has committed to voluntarily reduce its carbon footprint companywide 50% by 2030. We appreciate the opportunity to comment on the Proposal with our view on what is required to create the stable policy environment necessary to propel the State's solar market over the long term.

NJRCEV is committed to ongoing reductions in cost and improving the performance of our solar assets. We support the concept of a cost cap. However, we are concerned that the reductions of the caps from 9% to 7% in energy year 2022 are not well aligned with the State's clean energy goals.

We applaud the recent efforts of Governor Murphy and legislators to permit banking in relation to the annual cost cap compliance. This pragmatic approach will help avoid Staff's proposed "kink year" incentive structure which would have discounted the first three years of Transition Renewable Energy Credits (TRECs). Discounting incentives in the early years of these projects would inhibit a developer's ability to attain project financing, potentially curbing future solar growth. While the legislation provided is a good start, additional flexibility will be required to ensure that the cost cap compliance mechanism does not undermine the $12 billion invested in solar to date, and the confidence needed to sustain a thriving industry in New Jersey.

As indicated at the first solar transition workshop held in May 2019, solar stakeholders ranked **"being fair to those who have made prior investments"**[1] as the highest priority objective among the 25 items proposed by the consultants to guide the solar transition.

[1] Cadmus, Transition Incentive Supporting Analysis and Recommendations, July 5, 2019. Page 18

We are concerned with some of Staff's comments, conclusions and assumptions that reform of the legacy SREC program will aid in complying with the cost caps. Continual changes and revisions to key terms and conditions that formed the basis for investment decisions has been a fatal flaw of the SREC market, and new incentive structures, including TRECs for solar and Offshore Wind Renewable Energy Certificates (ORECs) for offshore wind, have acknowledged and addressed these issues.

Legacy solar assets and investors cannot sustain additional adverse impacts to SREC prices. The New Jersey solar portfolio returns are well below the returns modeled and intended by the State when the SREC market was designed. Any additional negative impacts to these investments will have significant consequences on the industry and on meeting New Jersey's aggressive clean energy targets.

NJRCEV and other industry participants have provided the transparent feedback and analysis underlying our conclusions that, unless the BPU ensures there is an Renewable Portfolio Standard (RPS) compliance obligation for all SRECs generated in the closed market needed to sustain market balance, there are major risks of irrevocably oversupplying the market, causing devastating impacts to the $12 billion already invested in the State. **The BPU has not shown commitment to a stable and balanced market in the final market closure Rule issued on January 25, 2020.**

We react with alarm to Staff's acknowledgement in the Proposal of the solar consultants forecast that SREC prices from 2027-2033 will reach $50/MWh, and the statement that these prices result from "market uncertainty." The consultant is quite clear that these prices assume "the SREC market so oversupplied that the market should be closed before 5.1% is reached."[2] In a closed market with no new entrants, that oversupply will occur as a result of policy decisions that are within the BPU's authority and control to mitigate. They are not the result of "market forces" as stated in the Proposal.

Staff has solicited input on fixed price or floor price offers for SRECs and questioned whether these offers should be voluntary. In an irrevocably oversupplied market, there would be no viable alternatives for market participants other than the fixed or floor price. If the fixed and floor prices do not reflect the needs of investors, the impacts to participants and the State's clean energy future could be devastating.

As currently constructed, due to omissions in assumptions in the solar consultants analysis, challenges exist in meeting the cost caps when they drop from 9% to 7% in Energy Year (EY) 2022, and through EY 2027, when significant capacity in the legacy market rolls off SREC eligibility and total annual costs will decline. Based on the consultants analysis, it will be impossible to comply annually with the proposed cost caps, grow the solar market, and meet with RPS without adopting flexible cost cap compliance rules including banking and borrowing cost cap surpluses and offsetting solar costs with benefits.

Accordingly, the cost cap analysis should include the following adjustments. The cost cap numerator referenced by Staff should reflect the following tangible benefit categories already in use by the BPU in other clean energy market segments: 1) Energy/Capacity Merit order; 2) Volatility Hedge benefits; and 3) Avoided Bill Savings from PPAs. Since these are already listed and defined in the Proposal, we will not repeat the definitions here.

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[2] NJ Solar Transition - Stakeholder Workshop #1; May 2, 2019; pg. 75 "Observations/Implications" Bullet #3

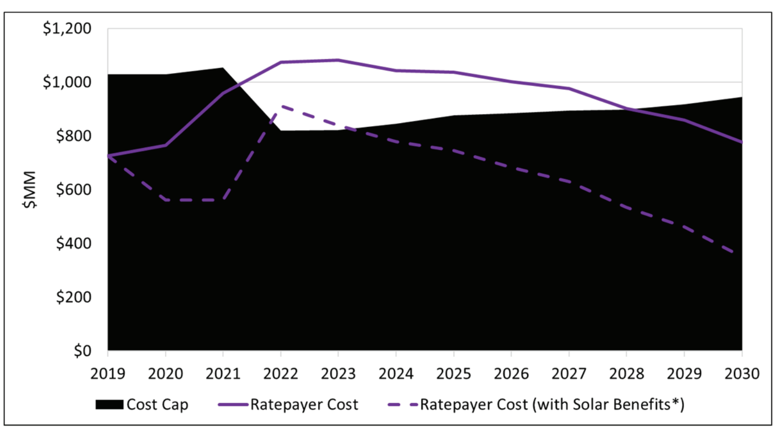
The denominator in the cost cap calculation should include the Total Paid for Electricity by All Customers. With this definition, costs should include: 1) Total electric utility generation, transmission and distribution costs; 2) Costs identified by the solar consultants and applied to their cost cap calculations in the workshops, including Electric Distribution Company (EDC) rate riders for Zero Emission Credits (ZECs) and ORECs; 3) Solar lease and PPA charges incurred by retail customers (these are similar in concept to costs retail customers incur for third-party Suppliers); 4) costs for energy efficiency programs administered by NJCEP and 5) assumptions on future retail electric rate increases consistent with the State's clean energy plan.

It should be noted that a study submitted by Morris and Somerset Counties and the New Jersey School Board Associations in this matter applies these net benefits and cost adjustments. This study indicates that there is adequate head room under the cost cap to support continued solar growth and respect legacy commitments.

Using the following slightly more conservative assumptions than assumed in the abovementioned study, as indicated in the graph below, NJRCEV has determined that cost caps could be met with only minor banking required in 2022 and 2023, under the following assumptions:

- SREC values for legacy projects are paid at the modified Cadmus Low Supply-Curve, which average 84% of Solar Alternative Compliance Payment (SACP) from EY 2020 - 2030 (Exhibit 2).[3]
- 400MW of new solar per year (consistent with the average pace for the past 3 years) to 2030.
- New solar under the successor program is paid at a $125/MWh average incentive under a fixed 20-year performance-based incentive.
- Installation of 625MW per year of offshore wind, starting in 2024, meeting the Governor's goal of 7,500MW by 2035.
- After considering the contribution to the RPS from new and legacy solar, and offshore wind, any gap required to meet the overall Class 1 RPS goal is satisfied by purchasing Class 1 renewable energy credits (RECs) generated from out of state facilities, assumed to cost $10/MWh (current market prices).
- The costs of renewables are offset with benefits from reduced energy and capacity payments New Jersey ratepayers will capture as in-state solar decreases the State's need to rely on out-of-state generation resources.[4]

Annual Incentive Costs Versus Cost Caps



[3] Cadmus curve modified by current SREC market prices to 2023; and prices in 2031-33 reflect average discount to SACP

[4] Referenced from above mentioned study derived from real time generation dispatch model run with and without NJ solar. Also referred to as the "merit order effect." NJRCEV does not believe benefits should be limited to this category alone but is modeling impacts conservatively.

A more detailed explanation of the data, assumptions and analysis used to derive the chart is contained in Exhibit 1.

Staff has also expressed a view in the Proposal that reform of the legacy SREC program will aid in complying with the cost caps and has posed questions about legacy payment restructurings, including reforms needing fixed price buyouts and floor prices with buyers of last resort.

NJR's views on restructuring are summarized below:

- Any restructuring **must be voluntary.** In this regard, the BPU's approach should be to create compelling offers that encourage participants to accept the offer. As previously stated, by default there will be no viable voluntary alternative with a distressed, irrevocably oversupplied legacy market.

- **The primary reform required is for the BPU to formalize its stated policy commitment to a stable and balanced SREC market by developing and implementing a market balancing mechanism**. Such action will establish a credible voluntary alternative and represents an important first principle for ongoing stakeholder engagement on restructuring options. Although a market balancing mechanism may not need to be applied, the availability of such a mechanism is a no-regrets approach that can bolster market confidence and mitigate market fears over the loss of value attributed to perpetual oversupply.

- Any proposed structure must respect, and not interfere with, existing contracts between SREC buyers and sellers since many hedge SREC generation into future years. This will be reinforced by making any restructuring proposals voluntary.

- The BPU can promptly initiate actions to develop a mechanism to maintain a balanced SREC market. This can be done by the express inclusion of this issue as part of the Successor Program, or as a separate proceeding. At a minimum, this mechanism should provide a compliance obligation for all SRECs in the closed market and consider approaches implemented in other jurisdictions, including the adoption of practices employed in Massachusetts (MA) in managing its two closed SREC markets, and the market divergence test that has been applied in New York.

    - The divergence test in New York determines if there are problematic imbalances between supply and demand. If such imbalances are deemed to exist and expected to persist, corrective actions are taken. In New Jersey, these corrective actions could include the BPU exercising its authority to increase the legacy solar RPS to offset the impact of material and detrimental oversupply.

    - MA has closed two SREC models and remains one of the most successful solar markets in the US, providing a best practice example of how a voluntary program that provides participants with a market option and buyer of last resort option can work.

        - The Massachusetts Department of Energy Resources (DOER), which administers the closed market, adjusts the RPS up or down every year with the goal to maintain a balanced market.

  - If the market is oversupplied, a floor price is available to sellers with a buyer of last resort (Load Serving Entities with RPS compliance obligation).

  - Massachusetts floor prices in the SREC-I market are currently $285/MWh, supporting projects installed from 2010-14. For SREC-II, which supports projects installed from 2014-18, the SREC floor price currently ranges from $244/MWh (2020) to $139 /MWh (2030). Massachusetts SREC 1 prices are currently trading at $365/MWh for 2020 compliance, and $315/MWh for 2023. SREC 2 prices are currently trading at $300/MWh for 2020 compliance, and $250/MWh for 2023.

- To meet the solar transition principle of protecting investor value, the BPU must consider the expected impact of any floor, fixed, cap or collar price structure on expected legacy solar investment performance. Just as the design of the TREC and incentive program explicitly considers the needs of solar investors, any proposed modifications to the legacy program must recognize historic install and operating costs and actual energy rates and SREC values. NJRCEV has shared its analysis on overall State level legacy project performance with policymakers in comments and testimony, in stakeholder proceedings, and in numerous meetings. We would be pleased to share this information again upon request.

- Development of price floors or fixed prices should also consider price benchmarks from other markets. In addition to the Massachusetts prices mentioned above, New Jersey's new TREC price supports new investments based on current install costs, establishing a $152/MWh levelized price for 15 years. Legacy projects encompass investments made at much higher installation costs, which accordingly require a higher incentive than new projects.

NJRCEV appreciates the opportunity to provide these comments and looks forward to ongoing discussion with Staff and stakeholders in this proceeding.

Respectfully,

DocuSigned by:
Lawrence Barth
D017221A586A43F...

Larry Barth
Director, New Jersey Resources

CC: Mark Valori, Vice President, NJR Clean Energy Ventures
Chris Savastano, Managing Director – Development, NJR Clean Energy Ventures
Robert Pohlman, Chief of Staff, New Jersey Resources

Exhibit 1: Cost Cap Analysis

illion MWH		74.6
ulation		-0.5%
		Cadmus
r		45.0%
r		1,200

[a] Cadmus Low Supply Curve
[b] Offshore wind installs assume 625MW per year from 2024-2035 to reach 7500MW goal
[c] "NJ Transition & Successor Solar" represents the 450MW transition program + a hypothetical new 10Y program, supporting 400MW per year on a fixed price 20Y BPI that starts at $125/MWh and decreases 5% each year
[d] Cost Cap figures from Cadmus/SEA report; 2031-2033 cost cap increase 3% annually

in millions, unless otherwise noted

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Vh)	74.6	74.3	73.9	73.5	73.1	72.8	72.4	72.1	71.7	71.3	71.0	70.6	70.3	69.9	69.6
	3.77%	4.65%	5.35%	5.51%	5.24%	4.90%	4.80%	4.50%	4.40%	3.70%	3.10%	2.20%	1.60%	1.40%	1.10%
	2.8	3.5	4.0	4.1	3.8	3.6	3.5	3.2	3.2	2.6	2.2	1.6	1.1	1.0	0.8
	$268	$258	$248	$238	$228	$218	$208	$198	$188	$178	$168	$158	$148	$138	$128
[a]	$230	$197	$197	$204	$199	$190	$181	$172	$158	$149	$144	$132	$91	$44	$7
	$647	**$680**	**$780**	**$826**	**$761**	**$677**	**$630**	**$558**	**$500**	**$393**	**$317**	**$205**	**$102**	**$43**	**$5**

10/MWh

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	14.18%	16.03%	21.00%	24.50%	28.00%	31.50%	35.00%	38.00%	41.00%	44.00%	47.00%	50.00%	52.50%	55.00%	57.50%
	10.6	11.9	15.5	18.0	20.5	22.9	25.3	27.4	29.4	31.4	33.4	35.3	36.9	38.5	40.0
	2.8	3.5	4.0	4.1	3.8	3.6	3.5	3.2	3.2	2.6	2.2	1.6	1.1	1.0	0.8
MWh [b]	-	-	-	-	-	2.5	4.9	7.4	9.9	12.3	14.8	17.2	19.7	22.2	24.6
& Successor Solar MWh [c]	-	-	0.5	1.0	1.5	2.0	2.5	2.9	3.4	3.9	4.4	4.9	5.3	5.3	5.3
	7.8	8.4	11.0	12.9	15.1	14.9	14.5	13.8	13.0	12.5	12.0	11.7	10.7	10.0	9.3
	$78	**$84**	**$110**	**$129**	**$151**	**$149**	**$145**	**$138**	**$130**	**$125**	**$120**	**$117**	**$107**	**$100**	**$93**
Wh	**10.6**	**11.9**	**15.5**	**18.0**	**20.5**	**22.9**	**25.3**	**27.4**	**29.4**	**31.4**	**33.4**	**35.3**	**36.9**	**38.5**	**40.0**
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

- PBI for 20Y

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
talled (MW)	-	-	450	400	400	400	400	400	400	400	400	400	400	-	-
ed	-	-	450	850	1,250	1,650	2,050	2,450	2,850	3,250	3,650	4,050	4,450	4,450	4,450
	-	-	0.5	1.0	1.5	2.0	2.5	2.9	3.4	3.9	4.4	4.9	5.3	5.3	5.3
	-	-	$125	$118	$113	$110	$107	$104	$101	$99	$96	$94	$94	$94	$94
	$0	**$0**	**$68**	**$120**	**$170**	**$217**	**$262**	**$305**	**$346**	**$384**	**$421**	**$456**	**$501**	**$501**	**$501**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
t	$647	$680	$780	$826	$761	$677	$630	$558	$500	$393	$317	$205	$102	$43	$5
	$78	$84	$110	$129	$151	$149	$145	$138	$130	$125	$120	$117	$107	$100	$93
t	$0	$0	$68	$120	$170	$217	$262	$305	$346	$384	$421	$456	$501	$501	$501
	$725	**$765**	**$958**	**$1,075**	**$1,082**	**$1,043**	**$1,037**	**$1,002**	**$975**	**$903**	**$858**	**$777**	**$711**	**$644**	**$599**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
d from Cadmus/SEA data)	$11,433	$11,433	$11,722	$11,714	$11,729	$12,086	$12,514	$12,643	$12,757	$12,829	$13,114	$13,500	$13,905	$14,322	$14,752
	$1,029	**$1,029**	**$1,055**	**$820**	**$821**	**$846**	**$876**	**$885**	**$893**	**$898**	**$918**	**$945**	**$973**	**$1,003**	**$1,033**
	$725	**$765**	**$958**	**$1,075**	**$1,082**	**$1,043**	**$1,037**	**$1,002**	**$975**	**$903**	**$858**	**$777**	**$711**	**$644**	**$599**
	$0	**-$203**	**-$396**	**-$163**	**-$243**	**-$264**	**-$291**	**-$319**	**-$345**	**-$369**	**-$397**	**-$428**	**$0**	**$0**	**$0**
able	**-$304**	**-$467**	**-$493**	**$92**	**$18**	**-$67**	**-$130**	**-$202**	**-$263**	**-$364**	**-$457**	**-$596**	**-$263**	**-$359**	**-$434**

Exhibit 1: Cost Cap Analysis (cont.)

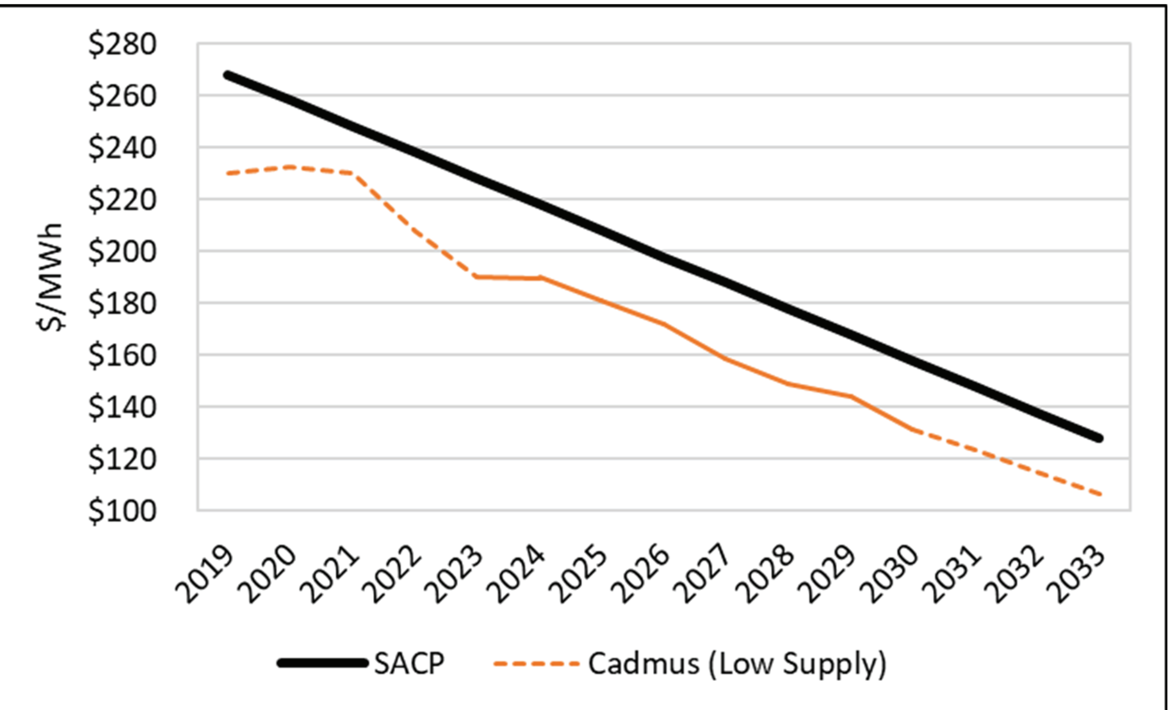
atepayer costs net of benefits to the cost caps each year.

nodified Cadmus "Low Supply-High Demand" SREC curve, discussed in Exhibit 2 which results in legacy SREC payments at

ment is calculated, assuming a price of $10/MWh, to meet the annual RPS goal by netting out the generation from legacy hore wind, the transition solar program, and a hypothetical successor program – building 400MW per year, under a 20-d Incentive (PBI) with a fixed incentive of $125/MWh. The fixed incentive is derived from the $152/MWh 15-year TREC 20-year incentive, and declining by 5% per year for each vintage thereafter.

lass 1 RECs, and new solar are reduced by the assumed merit order savings impact from the analysis provided to Staff in d by Somerset and Morris Counties and the School Board Associations. Under this scenario, the caps are met each year, uired in 2022 and 2023 to ensure compliance.

Exhibit 2: SREC Price Curve vs. SACP



SACP, in comparison to the Cadmus "Low Supply-High Demand" price curve presented in the solar workshops. The were made to the Cadmus curves:

EY 2019-2023 SREC prices were replaced with actuals from Karbone.

REC prices were increased to sustain the EY 2030 SREC discount to SACP, versus the reduction to Class 1 prices in the curve.

New Jersey Resources

January 16, 2020

Via Electronic Submittal: Charles.Gurkas@bpu.nj.gov

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 Clinton Avenue, 9th Floor
Post Office Box 350
Trenton, New Jersey 086258-0350

Re: Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps(Item#1 Banking)

Dear Ms. Camacho-Welch:

NJR Clean Energy Ventures ("NJRCEV") appreciates the opportunity to comment on the Staff Straw Proposal (the "Proposal") regarding the use of a banking mechanism to administer the Cost Cap requirements mandated by the Clean Energy Act of 2018 ("CEA"). We recognize and appreciate the efforts by Staff to develop this Proposal and engage with the solar industry on this important topic.

As a leader in the New Jersey solar market for the past decade, NJRCEV is proud of its accomplishments in driving down the cost of solar and improving the performance of our solar assets. On average, the installed cost of solar and solar incentive needs for new projects have declined by more than two-thirds over the past decade. NJRCEV is committed to continued cost and performance improvements.

While cost caps can be an important policy tool to manage the costs of energy transition, NJRCEV has consistently expressed concerns with the cost caps defined in the CEA. The reductions in the caps from the initial 9% rate to 7% in EY22 do not make sense considering the State's Renewable Portfolio Standard ("RPS") goal of 50% by 2030. The reductions also do not align to the solar transition requirement to ensure prior investments retain value, and the draft energy master plan goals supporting solar growth and preference for in-state clean energy resources.

As currently constructed, compliance with the cost caps on an annual basis will be impossible from Energy Year (EY) 2022 and EY2026, when the caps decline from 9% to 7%—and before capacity roll-offs from the legacy solar program become significant.

NJRCEV supports the utilization of "banking" as a methodology for cost cap compliance. Banking would measure compliance with the cost caps on a multi-year, cumulative basis. We believe a banking concept can be employed relatively quickly as a Phase 1 of cost cap compliance rules. Banking could also include "borrowing" from expected future cost cap bank surpluses to address any gaps which may emerge. As we mentioned at the stakeholder meeting on January 15, 2020, we also support further exploration of cost offsets to reflect the value of renewables, which could lead to a Phase 2 set of compliance rules.

Developing and implementing processes to define the data, methodologies and calculations to administer cost cap compliance are essential steps for the BPU to meet the Governor's goals. It will also leverage the expertise of the BPU in RPS compliance and oversight of clean energy programs. We will provide comments on specific details of the cost cap calculations, including the value of renewable offsets, on January 31, 2020 per your request.

NJRCEV believes it is essential that in adopting these new compliance rules the BPU should clearly articulate that it has authority to develop and implement rules on an ongoing basis. The recent passage of S4275/A6088 by the Legislature, which provides a specific solution to address early-year incentives in the transition program, must not limit the authority of the BPU to evaluate and modify the compliance rules as circumstances require to ensure the solar market remains strong.

NJRCEV appreciates the opportunity to provide these comments and looks forward to ongoing discussion with Staff and stakeholders in this proceeding.

Respectfully,

Lawrence Barth

Larry Barth
Director, New Jersey Resources

CC: Mark Valori, Vice President, NJR Clean Energy Ventures
Chris Savastano, Managing Director – Development, NJR Clean Energy Ventures
Robert Pohlman, Chief of Staff, New Jersey Resources

Joint Comments on "Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps"
1/30/2020

The Solar Energy Industries Association (SEIA) and the New Jersey Solar Energy Coalition (NJSEC) submit the following comments pursuant to the January 7, 2020 Notice issued by the New Jersey Board of Public Utilities (the Board or BPU) on the secondary set of questions in the matters of: Defining Terms of the Clean Energy Act, and Reform of the Legacy SREC program.

NJSEC and SEIA appreciate the time, and effort the board has put into examining these important policy issues and their solicitation of comments from stakeholders.

SEIA is the national trade association for the solar industry and NJSEC represents thousands of New Jersey employees engaged in all facets of New Jersey solar energy development.

Answers to Specific Board Questions:

With regard to calculating the Cost Cap, Staff requests responses to the following questions:

1. Do parties agree that Staff has correctly identified the numerator and the denominator?

Yes, the definition provided by staff for both the numerator and denominator would result in an intellectually defensible calculation for 5.1%. Having said that, the elements that would be included in the calculation of both the numerator and denominator are based upon assumptions over which reasonable people might disagree. Perhaps more important than judging these arguable assumptions on a purely mathematical and intellectual basis, we should look to the implications of these judgments on the resulting impacts on the more global goals of the program. Clearly, the statute and all of the orders adopted by the board to date have recognized the importance of closing the market in an orderly fashion that will result in "ensuring that prior investments retain value." Therefore, it would appear far more appropriate to select calculation metrics that might reflect honest differences of opinion to close the market in as balanced a fashion as possible. That calculation would best reflect the objectives and goals sought.

2. Staff notes that the State's Class I REC programs have resulted in benefits to the citizens of the State of New Jersey, including improved public health, reduction in carbon emissions, and direct financial benefits, such as lower energy and capacity costs.

   a. Is it appropriate for the Board to factor these benefits into the Cost Cap Equation?

Overall, the value of solar proposition represents a very effective way of evaluating the costs and benefits of New Jersey's renewable clean energy program. However, the cost elements associated with this evaluation can produce vastly different results based upon a myriad of very complicated and overlaying assumptions. As we have witnessed in other states, value of solar calculations has produced vastly different results.

We are also of the opinion that deliberations establishing a more precise value of solar would be very time-consuming and result in a considerable strain on already stressed board resources. We are of the opinion therefore that questions of value should be considered in the context of the design of the successor program but should be left out of the cost cap calculations at this time, particularly in view of the fact that there appears to be sufficient headroom now available to obviate the need for this additional complication.

b. If so, please comment on which categories of benefits, if any should be included, whether they should be included in the numerator or denominator, and how they should be calculated.

See answer to sign 2 a. above

3. The numerator is defined as the "cost to customers of the Class I Renewable energy requirement."

Yes.

4. Staff's current practice in calculating clean energy program costs is to aggregate retired quantities from the annual RPS compliance reports of load serving entities and apply the last price recorded in PJM-EIS Generation Attribute Tracking System ("GATS").

a. Is there a better source of data and calculation methodology?

It would appear that this methodology could be more accurately stated if the average price recorded in the PJM – EIS generation attribute tracking system over that same period were used rather than the last price recorded.

b. If so, how would we measure those costs?

See answer to #4 a. above

c. Should the Board analyze what energy costs would have been without the Cost Cap-Eligible Programs to determine the appropriate net cost to consumers of the programs?

Inasmuch as including these costs in the denominator would provide more "headroom," under the cost cap we would support the inclusion of these costs in the calculation.

d. If so, how should such an analysis be conducted?

Apply the statewide weighted average cost by market segment multiplied by the average generation of each segment over the past twelve months to maintain consistency with the current market closure calculations.

e. How should Staff handle savings associated with the "merit order effect" whereby renewable energy and load reductions reduce the market price of capacity and energy rates to all customers?

Inasmuch as it would be difficult to obtain consensus on these and many other market price impacts, we believe they should be ignored for the purposes of these broad calculations.

f. How should savings received by customers who install on-site renewable energy be addressed?

See 4e. above.

g. Are there volatility hedge benefits that should be included?

See 4e. above.

5. The denominator of the Cost Cap Equation references "total paid for electricity by all customers in the state."

Yes.

a. Should payments associated with solar installations be included in the denominator? Should the Board differentiate between host-owned and third-party owned systems?

See 4e. above.

b. Are there other types of customer-generated electricity whose costs should be considered? For example, should the Board include electricity costs incurred by owners of Combined Heat & Power systems, microgrids, or other large on-site generators?

See 4e. above.

c. Should associated finance costs be included?

See 4e. above.

d. Should delivery charges imposed by the Electric Distribution Companies ("EDCs") be included?

We have assumed that they are already included in the total cost of retail sales by definition,

d. Should Staff calculate the costs just to Board-jurisdictional load, as is the case for RPS compliance currently?

Yes

f. Should Staff calculate the costs as the sum of all EDC sales to end-use customers?

Yes

a. Should we rely on Energy Information Administration ("EIA") sales data?

The Board should rely upon the most accurate and timely data available.

b. Is there a better source of data and calculation methodology?

See 5 (f.) (a.) above.

c. How should the lag in EIA data be addressed?

See 5 (f.) (a.) above.

d. Should non-by passable surcharges, including such things as Zero Emission Credits, be included in our calculation of energy costs?

Yes, inasmuch as these costs are already embedded in retail rates.

Staff's view is that reform of the SREC program will aid in complying with the Cost Caps. Staff requests comments from parties on the following questions regarding how such reforms to the Legacy SREC program could be structured:

1. Should Staff consider reforms to the SREC market in order to reduce the variability in potential SREC outcomes?

Our organizations remain concerned that the adopted market closure mechanism may create market instability and may result in very high or very low prices in the legacy SREC market. However, we also recognize that there are many variables that will impact on solar legacy market price and any one outcome is uncertain.

Given this uncertainty, the Board should closely monitor the legacy market and be prepared to intervene and create a "market balancing mechanism" as needed. The Board has the statutory obligation to close the current SREC market in an "orderly and transparent" way and the Board and Administration have repeatedly supported the important principle that the value of legacy investments be preserved.

Unlike an open market with new project entry, a closed market cannot self-correct, and therefore it is entirely up to the Board to prevent significant swings in prices in either direction. Although the Board has a number of known tools at its disposal to manage the market, such as establishing an SREC floor price at a an adequate level based off the SACP, creating a buyer of last resort, and even slightly increasing the legacy RPS, we do not recommend a specific action at this time, only that the Board should be prepared to develop a suitable mechanism when and if it is needed.

2. Should owners of SREC contracts be required to take part in any restructuring of the program, or should participation be voluntary?

> The answer to the question of whether owners of SREC contract should be required to take part in market restricting depends on the action under consideration. For instance, if the Board acts to prevent closed market pricing instability by establishing an adequate floor price, then all SREC contract owners must be required to participate. However, if the Board offered a fixed price "buy out" for SREC owners, then participation in an option such as this ***must*** be voluntary. A mandatory restructuring, or in other words requiring all projects to take the buyout, would have enormous negative consequences and would likely result in litigation that would severely impact future investment in New Jersey's renewable energy future.

3. Should Staff examine moving toward converting SRECs to a fixed price product, or would it be better to look at a lower Alternative Compliance Payment ("ACP") and the institution of a floor price or buyer of last resort?

> See #1 above.

4. If Staff were to recommend setting a fixed price for SRECs, how should that price be set?

> See #1 above.

5. If Staff were to look at a lower ACP and buyer of last resort program, how should such a program be structured?

> See #1 above.

6. Should the Board consider a "tight collar"? How would such a program be implemented?

> See #1 above.

7. Are there other reforms that Staff should consider?

> In the context of a more open and collaborative process engaging Board staff on policy issues, NJSEC and SEIA would welcome that opportunity.

Staff requests additional thoughts on ensuring compliance with the statutory cost caps while also allowing for a robust solar Legacy, Transition, and Successor Incentive programs.

> See #7 above.

Thank you. Please contact David Gahl (dgahl@seia.org) or Fred DeSanti (fred.desanti@mc2publicaffairs.com) with questions about these comments.

Respectfully submitted,

/s/
David Gahl
Senior Director of State Affairs, Northeast
Solar Energy Industries Association

and

Fred DeSanti
Executive Director
New Jersey Solar Energy Coalition

Comments of NRDC and NJCF

on

Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps

On January 6, 2020, Staff of the BPU issued its Notice in the above captioned matter, seeking comments on three issues:

1. The inclusion of a banking mechanism to allocate available annual surpluses or "headroom" under the Clean Energy Act's RPS Class I cost caps;
2. Stakeholder input on how the cost caps should be determined and implemented; and
3. Potential reforms to the Legacy SREC program to ensure a robust solar market while conforming to statutory limitations on cost and fulfilling statutory renewable energy deployment requirements.

We appreciate the Staff's straw proposal, and generally respond to these issues by referring to the detailed comments they have previously filed in the various solar transition proceedings since the passage of the Clean Energy Act. In those filings, we have repeatedly advocated the following:

- The carrying forward of one year's "headroom" or unspent surplus under the RPS cost cap to apply to one or more future year's RPS spending;
- The consideration of including measurable, net ratepayer benefits as an offset to the direct costs included in the denominator of the cost cap equation, as laid out on page 3 of the January 6 Straw Proposal, as necessary to be able to meet the statutory renewable energy deployment goals within the statute's class 1 cost caps;
- The prompt development of steps to ensure that SREC prices in the legacy program, after the closure of the program to new participants, are neither so high as to impede compliance with the statutory RPS cost caps and renewable energy deployment requirements, nor so low so as to unfairly impair existing solar projects.

With respect to the straw proposal's detailed questions regarding the second and third of these issues, we offer the following brief responses to questions where we believe our insights will help the BPU develop effective and fair policies.

On the inclusion of net, measurable benefits as an offset to costs, we believe it would be most appropriate to include those benefits that are most directly attributable to the clean energy resources themselves. For example, avoided emissions due to increased renewable energy production provide direct health benefits to New Jersey residents, and can be estimated with good accuracy by a number of established and sophisticated analytical techniques. By contrast, direct financial benefits in terms of reductions in wholesale market energy and capacity prices (which is what we understand staff to mean by "the merit order effect") can be caused by a wide variety of factors, including fuel prices, weather, the construction of new fossil or renewable power resources, and reductions in demand. Further, wholesale prices can be increased substantially by the retirement of older, less efficient power plants, and increases in demand, e.g. from the electrification of new end uses. Some of these factors, such as power plant retirements, can themselves be driven by more renewable energy deployment, which means renewable energy deployment could act to increase wholesale power prices, as well as to decrease them. For these reasons, we recommend considering only direct, measurable benefits such as health benefits from reduced air pollution.

On what to include in the numerator and denominator of the cost cap equation, we believe the following principles will be most in line with the clear reading of the statute. The numerator should include only money spent on class I renewables that is collected from retail ratepayers in the state through their electric bills, and the denominator should include all money that is collected from retail ratepayers in the state through their electric bills.

For example, the cost of SRECs, RECs, and ORECs are collected from retail customers through their electric bills, and they are class I renewables, so they should be included in both the numerator and the denominator. The cost of ZECs and delivery charges are collected from retail customers through their electric bills, and they are not class I renewables, so they should be included in the denominator. The cost of building a solar installation on an individual rooftop or parking lot is not collected from retail customers through their electric bill, so it should not be included in either the numerator or the denominator. The cost of electricity from a behind-the-meter standby generator, co-generator, or microgrid is not collected from retail customers through their electric bill, and is not a class I renewable, so it should not be included in either the numerator or the denominator. To the extent any costs from such a distributed energy resources that are recovered through billing credits for net-metered "exports", these costs are already counted in the denominator by simply including all retail energy sales in the denominator.

Regarding ensuring legacy SREC prices remain at levels that are neither too high nor too low to achieve the goals of the solar transition, we have previously advocated for a "price collar" approach, with the top end of the price range constrained by a mechanism that would function like the SACP, but would be established at a lower level by the BPU under its authority to do whatever is necessary to ensure compliance with the RPS cost caps. We have suggested evaluation and careful consideration of several alternatives for the mechanism that would create the price floor, including a buyer of last resort approach, and an opt-in to a new solar compensation program that would offer a fixed price for a fixed term. If the combination of this lower price and a longer term were more attractive than the levels to which the legacy program could fall, enough legacy projects could be expected to voluntarily opt-out of the legacy market and into the new, fixed price program to cause SREC prices to fall to the level of the new program. Such a program could, for example, be set up as part of the successor program or potentially even as part of the modified SREC program.

However, for any such program, like all of the issues raised in the January 6 straw proposal, to work in a fair and effective manner requires the full engagement of stakeholders in response to a concrete, specific straw policy proposal from staff or its consultants. As with the solar transition program, such an iterative process of concrete proposal and detailed analysis and feedback by solar parties and other stakeholders, is the best way to develop any innovative and workable new solar policies. NRDC and NJCF look forward to participating in such a process on these important issues.

Rockland Electric Company
Response to Notice Seeking Comments on
Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps
January 31, 2020

Rockland Electric Company (RECO) submits these comments in response to the New Jersey Board of Public Utilities' January 6, 2020, Notice requesting comments on Staff's Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps, specifically Items 2 and 3. RECO appreciates Staff's efforts to engage stakeholders as to how the Cost Cap, as provided for in the Clean Energy Act, should be implemented.

As RECO has stated in prior comments, the Clean Energy Act's goals and the continuation of a successful solar program in New Jersey must be managed with customer bill impacts in mind. The Clean Energy Act recognizes this important objective with the provision of a Cost Cap on Class I Renewable Portfolio Standard (RPS) program incentives. Managing the bill impact of the Class I RPS programs is critical to meeting the state's clean energy goals. The Clean Energy Act and other clean energy initiatives in New Jersey include not just increasing the RPS targets, but also the development of offshore wind, energy storage, electric vehicle and energy efficiency programs. These goals put New Jersey on the path to a clean energy future and will require significant investment, in particular from utility customers. The Class I Cost Cap attempts to limit the impact of one part of these clean energy initiatives and should be developed using a holistic approach that accounts for the total customer bill impact that will result from the pursuit of a clean energy portfolio. As discussed below, in response to Items 2 and 3 in the Notice, RECO supports calculating the cost cap in a way that embraces the Clean Energy Act's intention to manage customer bill impacts.

Defining the Terms of the Clean Energy Act

The Clean Energy Act provides that:

> Notwithstanding the requirements of this subsection, the board shall ensure that *the cost to customers of the Class I renewable energy requirement* imposed pursuant to this subsection shall not exceed nine percent of the total paid for electricity by all customers in the State for energy year 2019, energy year 2020, and energy year 2021, respectively, and shall not exceed seven percent *of the total paid for electricity by all customers in the State* in any energy year thereafter (emphasis added).

In the Notice Staff proposes that in determining the cost cap, the numerator is the "cost to Customers of the Class I Renewable Energy Requirement" and the denominator is the "total Paid for Electricity by All Customers in the State."

Staff has correctly identified the numerator and the denominator for calculating the Cost Cap. When looking at these two terms, combined with the intent of the legislature in providing the Cost Cap, RECO recommends a straightforward approach to identifying these values that is consistent with the purpose of providing a cost cap:

- For the Numerator: RECO supports the use of annual compliance reports to determine the retired quantity of Class I RECs in a year. RECO also supports the use of PJM-EIS Generation

Attribute Tracking System (GATS) as a resource for the number of RECs retired. Determination of the price of the RECs should be as accurate as possible. Because the Class I prices have not varied significantly in the past few years, using the last price paid during the year to calculate the numerator may be an adequate representation of the cost of RECs during the entire year.

- For the Denominator: RECO recommends that the "total paid for electricity" include only the supply charges customers paid for electricity. If it is determined that both supply and delivery charges paid by customers are included in the denominator, then it should not include the cost for other clean energy initiatives, *e.g.,* the Offshore wind Renewable Energy Certificate, Societal Benefits Charge (SBC), Regional Greenhouse Gas Initiative, Zero Emission Credit, nor costs incurred by certain subsets of customers such as those that have installed on-site generators. Including these charges in the "total paid for electricity" overstates the amount customers are paying for electricity, and, contrary to the statute, raises the cap beyond what the legislature intended. Taking a limited approach allows Staff to compare the cost of the Class I program against what customers are paying for electricity and minimizes the complexity that could arise from inclusion of additional costs and investments.

Finally, RECO appreciates the point that as more clean energy and EE programs are scaled and adopted there will be benefits such as improved public health, reduced emissions, and financial benefits such as lower energy and capacity costs. However, incorporating these into the cost cap calculation misses the intent of the cost cap, which is to protect customers by managing the bill impacts of one specific set of programs within the entire suite of clean energy programs offered in the state. Benefits such as improved public health and reduced emissions will be difficult to demonstrate as a bill impact for customers. Potential benefits such as lower energy and capacity costs should flow to customers as a benefit for all they have invested into these programs, but not used to circumvent the intent of the Act to limit bill impacts to customers.

Reform of the Legacy SREC Program

RECO supports Staff's efforts to examine ways to limit the cost impact of the legacy SREC program in order to comply with the Clean Energy Act's Cost Cap and balance the development of future projects. Any effort to adjust legacy SREC project costs should have as its first priority the total bill impact to customers. RECO supports measures that also keep in place a market-based approach, for example lowering the ACP. Measures, such as a price floor or buyer of last resort, will interfere with the Legacy Program operating as a market. Further, changes to an established program such as the legacy SREC program adds complexity and creates an additional administrative burden on those administering the programs.

Rockland Electric Company
Response to Notice Seeking Comments on
Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps
January 16, 2020

Rockland Electric Company (RECO or the Company) submits these comments in response to the New Jersey Board of Public Utilities' Staff (Staff) January 6 Notice requesting comments on Staff's Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps.[1] RECO supports the Clean Energy Act's goals and the continuation of a successful solar program in New Jersey, all of which must be managed with customer bill impacts in mind. RECO applauds the Clean Energy Act's recognition of the potential increases to customers' bills and the mechanism to manage this impact by providing for a Cost Cap on Class I Renewable Portfolio Standard (RPS) program incentives.

Managing the bill impact of the Class I RPS program is critical to meeting the state's clean energy goals. The Clean Energy Act goals include not only increasing the state's RPS targets, but also providing for the development of offshore wind, energy storage, and energy efficiency programs. In addition, the state has announced ambitious offshore wind targets and achievement of 100 percent clean energy by 2050. These goals put New Jersey on the path to a clean energy future but will also require significant investment, in particular from utility customers. RECO recommends that a holistic approach, be taken to develop rules around the cost cap calculation that acknowledge, and accounts for the impact of other renewable and clean energy incentives, such as ORECS, EV incentives, EE rebates, and storage incentives - similar to the holistic approach taken in the Energy Master Plan and Integrated Energy Plan to identify cost effective and least cost measures to reach state targets. This will result in the creation of programs and incentives that balance achievement of the clean energy goals with the management of ratepayer impacts.

RECO submits the following responses to the questions posed in the notice.

1. **Should the Board adopt a true-up banking methodology so that any expenditures above or below the Cost Cap in one Energy Year are carried forward to a subsequent year?**

Response:
RECO recommends that any banking mechanism adopted must be viewed in the context of the impact to customers' bills, the potential limiting impact it may have on investment in and development of other clean energy initiatives outside the Class I RPS program, and the administrative complexity it may create.

A holistic approach to the management of the bill impacts of all of the clean energy programs is critical to mitigating, to the extent possible, the bill impact to customers in a given year. The creation of a banking mechanism must not overlook the total bill impacts of clean energy programs, which may vary widely from year to year. Although the total spent under the Cost Cap over a period of years may not change with a banking methodology, such a methodology may result in the total bill impact to increase

[1] These comments are limited to the contents of the notice and the effective language in the 2018 Clean Energy Act as of January 16, 2020. RECO is aware the New Jersey legislature recently passed a bill amending the Clean Energy Act's cost cap language (Senate Bill No. 4275). However, since this amendment has not been signed into law, RECO does not comment on the changes to the cost cap contained therein.

significantly in a year with banked dollars while not seeing a corresponding decrease in a prior year. This would occur if other non-cost cap programs were developed in a Below Cost Cap year, resulting in the same impact had the Class I RPS program used the full extent of the cap that year. Then, in the following year, a customer would not only possible see the additional costs of the banked Class I RPS program amount but also the costs for the new programs. As a result, in an effort to try and average out the room under the cost cop for the RPS Class I program, the result may in the end lead to large spikes in customers' bills. This may result in potential rate shock for customers, particularly in years when a large carryover is added to a current year's bills. This would disproportionately impact low-income customers and may have unintended consequences on the State's USF and other low-income assistance programs which seek to help customers pay their bills and avoid turn off for non-payment. Likewise, such bill fluctuations could have a negative impact on businesses planning their annual budgets, creating an unfriendly environment for commercial customers and in particular energy-intensive customers.

Creation of a banking mechanism may not eliminate the uncertainty surrounding the amount of cost cap available each year; this uncertainty may have a negative effect on any market-based programs, including for example the Successor SREC program which may be market-based as well as the Legacy SREC program which is a market-based program.

Finally, the administrative complexity created by managing a banking mechanism under the cost cap may increase the tracking of costs and expenditures, reporting requirements, the management of stakeholder processes and involvement, and the review and approval processes for finalizing the carryover amounts. As a result, RECO recommends the following be considered if a banking mechanism is adopted to mitigate large spikes in customer bills from year to year:

- A limit on the amount that can be banked from each year that is under, minimized to the extent possible and determined upfront;
- A limit on the life of the carryover of any unused bank space;
- A cap on Class I RPS programs for years a banked amount is applied. For example, in a year a banked amount is rolled over, Class I RPS programs can still not exceed an identified percentage (*e.g.,* 10 percent);
- In years where the banked cost cap amount is used, the Board should develop a process to provide stakeholders the opportunity to review the calculation of the year that came in under the Clean Energy Act cost cap and the total bill impact of the year in which the banked cost cap amount is to be used. A date certain for a final determination must be set upfront (e.g., September 15 of each year). This will help stakeholders and the Board work to avoid exceeding the overall Cost Cap.

2. Would allowing for banking between Energy Years affect the total ratepayer impact?

Response: Please see RECO's response to question 1. Although the total ratepayer impact from Class I Renewables should in theory be the same with or without banking over a given period of years, because of the potential for new programs to be developed to take advantage of years when costs are much lower than the Cost Cap, this could result in a significant bill impact to customers in subsequent years, especially those when the Cost Cap is reached. Carryover of unused Cost Cap amounts could result in large bill impacts that disproportionately impact low income customers as well as commercial customers.

3. **Should the Board consider averaging costs over a period in order to more accurately reflect total compliance costs, while smoothing transient effects? How would such an average be constructed?**

Response: A banking methodology would not inherently smooth bill impacts from clean energy programs, since costs from all clean energy programs will result in customer bill impacts. In addition, a banking methodology that attempts to "smooth" transient effects may result in the need for complex and potentially burdensome and time-consuming calculations and studies that would determine when such a smoothing would be needed and what would constitute "smooth."

4. **Should the Board adopt a true-up banking mechanism that can utilize unspent headroom from previous years as well as anticipated/projected headroom from future years?**

Response: The purpose of any analysis performed to determine the appropriate and allowable (under the Cost Cap) incentive should not be focused on utilization of the entire amount of headroom available in any given year. Rather, incentive and program structure should be developed based on the needs of the renewable asset and the State's needs to meet the clean energy goals. The cost cap is a way to balance the needs of the developers / asset owners and the achievement of New Jersey's clean energy goals with the financial burden on customers.

5. **How should the accounting for such transfers be done?**

Response: Transfers should be accomplished pursuant to specific formulas and using public data, and should be published for public comment and review.

Ad Energy appreciates the opportunity to provide comments related to the implementation of the Clean Energy Act of 2017 cost caps. Ad Energy offers comments on question #3:

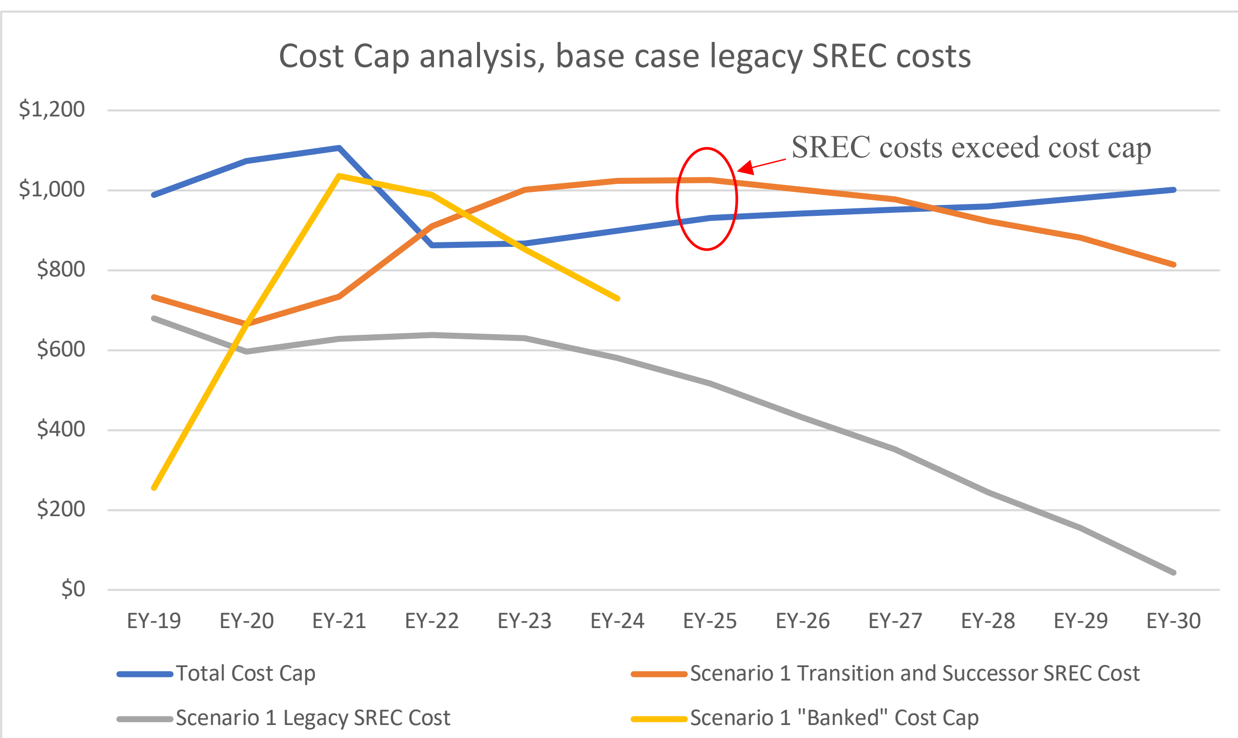
3) Explore reforms to the Legacy SREC program that ensure a robust solar market while conforming to the statutory limitations on cost.

Ad Energy is a primarily residential solar installation company, is based in New Jersey, and has been operating since the beginning of 2015. Ad Energy is not a significant participant in SREC markets, but we do have exposure to the market through finance partners and customers.

<u>Statement of the problem – Cost Cap constraint</u>

Recent changes to cost cap calculation methodology – the ability to "bank" – has alleviated short term concerns. However, our model suggests that a cost cap problem remains starting in energy year 2025 and continuing from then for several years. Thus, the cost of the legacy SREC program still poses a risk to the solar market viability in the medium term.

Scenario 1 of our model uses the base case Cadmus forecast of October 2019 for legacy SREC costs. It further assumes that an SREC incentive similar to the current proposed Transition Incentive continues as the Successor Program. For simplicity we have assumed a "blended value" fixed SREC at $130 for the Transition Program and for EY21-23 for the Successor Program, with the SREC value declining to $120 in EY24 and a further decline of $10 per year from there forward. We assume a development market of 500 MW placed in service per year.



Note that there is a large "banked" cost cap balance at the end of EY24. This is suggestive of a potential solution.

<u>Statement of the problem – existing forward SREC purchasing contracts</u>

A common suggestion we have heard in dealing with the legacy SREC costs is to offer a trade: lower SREC costs in the near term in exchange for long term price certainty. We have in the past supported such a proposal. We no longer do. The proposal suffers from two major flaws.

The first flaw is that it no longer offers enough relief on the cost cap constraint. That constraint has now shifted to EY25, and fixed values we have heard discussed would be inadequate to provide EY25 cost cap constraint relief.

The second issue relates to forward fixed-price SREC purchase contracts. These are typically priced highly for 3 years, at values close to the current spot market price. Any decrease in SREC value in the short term in exchange for price certainty long term would put substantial pressure on unwinding these existing contracts. Furthermore, in order to have near term benefit, many of these contracts would ***need*** to unwind. In particular, to the extent that these contracts have involved substantial prepayments, or support debt covenants, to say that this unwinding would be messy is an understatement.

<u>Statement of the problem – the consumer</u>

We can't stress this enough. The typical homeowner participating in the SREC market doesn't understand it ***at all***. Whatever we do with the legacy SREC program, it needs to provide some protection for homeowners that have simply used past SREC market behavior as an assumption for future SREC market behavior.

<u>Our proposal</u>

Because there is so much uncertainty in the current (legacy) SREC market, investors in solar projects, when analyzing project returns, do not rely on much value from SRECs several years in the future. The first three years of SRECs provide most of the assumed value. This suggests a solution:

1) guarantee a floor price for legacy SRECs that mimics available fixed price purchasing agreements, and
2) issue a statement on what SREC value the BPU will use to plan Successor program incentive.

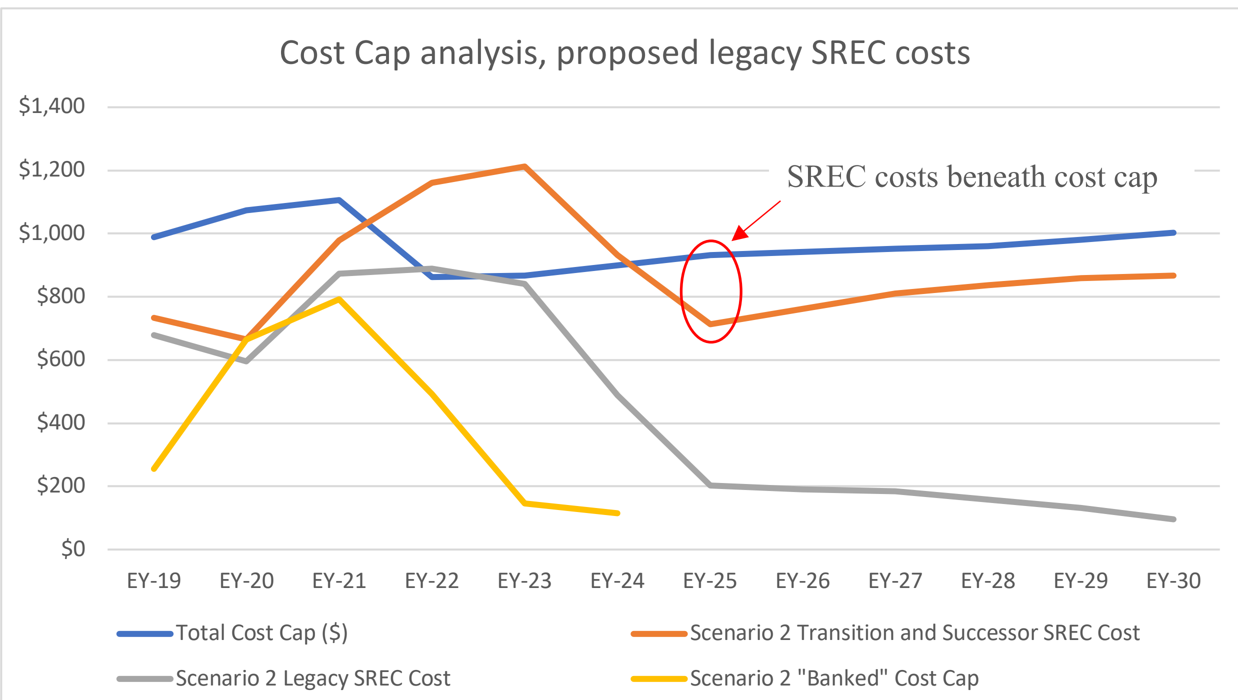
The BPU should provide a floor price guarantee for legacy SRECs. The values should be set so that they mimic typical forward contracts available on the market today. This will both ensure adequate returns for recent investors in solar projects, and will sharply reduce any incentive to unwind existing forward purchasing contracts. Additionally, consumers will be protected.

Additionally, borrowing from price signaling strategies employed by the Federal Reserve in managing interest rates, the BPU should articulate a "planning price" for legacy SRECs. This value should be close to, but higher than, the guaranteed floor price. The BPU should use this planning price in designing the Successor SREC program. Market participants would follow this signal when trading SRECs, knowing that the BPU is now required by law to reduce the RPS if the cost cap is exceeded. If necessary, the BPU should be prepared to reduce the legacy RPS if the cost cap is exceeded.

We suggest a floor price similar to the following:

EY21	$225
EY22	$225
EY23	$225
EY24	$140
EY25+	$50

Our forecast of cost cap compliance, assuming the legacy SRECs trade at the floor price, is below. Note that the "banked" cost cap balance is much lower than in the base case.



Joint Comments on "Staff Straw Proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps"
1/16/2020

The Solar Energy Industries Association (SEIA) and the New Jersey Solar Energy Coalition (NJSEC) submit the following comments pursuant to the January 7, 2020 Notice issued by the New Jersey Board of Public Utilities (the Board or BPU) on the overall question of whether the Board *should* employ a banking mechanism to administer the Clean Energy Act's (CEA) cost caps.

SEIA and NJSEC appreciate the time and effort the Board has put into the solar transition and is grateful to the Board for launching this important proceeding on calculating the cost caps. *In brief, we strongly recommend the Board employs a banking mechanism when calculating the caps*.

SEIA is the national trade association for the solar industry and NJSEC represents thousands of New Jersey employees engaged in all facets of New Jersey solar energy development.

Part 1 - The Case for "Banking"

The paragraphs of the CEA setting the cost caps provide considerable flexibility to the Board in determining their actions to meet it. The CEA reads "The board shall take *any steps necessary* [*emphasis added*] to prevent the exceedance of the cap on the cost to customers including, but not limited to, adjusting the Class I renewable energy requirement." This language gives the Board considerable latitude for implementation.

Read in context with the rest of the statute, the language on the cost caps allows the Board considerable leeway on managing compliance with these limits. The CEA determines two thresholds to contain impacts of the clean energy transition on ratepayers – nine percent in the early years and seven percent thereafter. In the same way that CEA empowers the Board to meet specific Class I Renewable Portfolios Standard (RPS) targets in five-year increments and gives the Board the discretion on a year-to year-basis to reach them, the CEA also sets overall cap thresholds, but leaves the specifics about calculating the caps and compliance with the caps to the Board.

Eliminating any shadow of doubt, the New Jersey Legislature's recent passage of S.4275/A.6088 clarifies and leaves no question about the Board's authority on using banking. This pending legislation provides the Board with an important tool that can be used to maximum advantage based on prevailing circumstances. By employing banking, a "reserve" could be calculated at the end of each energy year and carried over and added to cost cap calculations in the following years.

There are several important benefits to using banking. Banking would allow for a higher Transitional Renewable Energy Credit (TREC) incentive in the "kink" years and would allow the

Board to set a level incentive for the entire 15-year qualification life. The current incentive level is lower in the first three years when the risk of exceeding the caps is highest. While solar firms would likely be able to manage different levels of fixed incentive payment during the 15-period, the lower values in the first three years would result in higher financing costs for projects. A better incentive would pay a levelized amount over time. Employing banking would also allow for additional flexibility in determining incentive values as part of the successor solar incentive program.

Part 2 - Answers to Specific Board Questions:

1. Should the Board adopt a true-up banking methodology so that any expenditures above or below the Cost Cap in one Energy Year are carried forward to a subsequent year?

   Yes. As stated above, this mechanism would provide the Board considerable flexibility in implementing the CEA and help ensure the stability of the New Jersey solar industry. The legislature's recent action eliminates any doubt that the Board has this authority and the pending legislation should be signed by the Governor into law.

2. Would allowing banking between Energy Years affect the total ratepayer impact?

   Spending money that is unspent in previous years will have a ratepayer impact. However, the question is perhaps better framed in the context of whether or not this nominal ratepayer impact will be more than offset by the clean energy and jobs benefits associated with continuing the program at existing robust levels to help assure that the Governor's vision is achieved.

   The legislature has reassessed the statutory cap in the current legislation and approved the banking methodology as a means of smoothing the transition between the 9% and 7% limits while concurrently maintaining the overall cost containment requirements. Both NJSEC and SEIA strongly support this important measure of statutory flexibility.

3. Should the Board consider averaging costs over a period in order to more accurately reflect the total compliance costs, while smoothing transient effects? How would such an average be constructed?

   No, the legacy cost reductions associated with the end of their eligibility periods will, in the next few years, dramatically reduce the cost of the solar program. Recasting these costs at this time would serve only to slow these cost reductions and further extend the cost impacts of the legacy program into the future restraining design options. New Jersey would be far better off designing the successor program to gear up for far more rapid growth in the coming years unfettered with yet another amortization of historical costs.

4. Should the Board adopt a true-up baking mechanism that can utilize unspent headroom from previous years as well as anticipated/projected headroom from future years?

   Yes. Our organization supports the Board adopting a true-up banking mechanism that can utilize unspent headroom from previous years, as well as anticipated/projected headroom from future years, if needed. SEIA and NJSEC recognize that the Board is tasked with administering RPS in a way that minimizes ratepayer costs while achieving the statutory renewable deployment mandates. For the Board to effectively do both, it should use all tools at its disposal to maximize certainty in the RPS mandates, as well as in REC values. That additional certainty corresponds to lower project development risk from the private renewables sector – namely through lower financing risks.

5. How should the accounting for such transfers be done?

   Given the fact that the successor program and its "headroom" need have not yet been established, and the fact that the transition program build and pipeline scrub rate are, as yet, unknown, it is far too early to opine on the accounting specifics. Once these needs are understood we will all be in a far better position to assess the use of this new discretionary tool to maximum advantage.

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Thank you. Please contact David Gahl (dgahl@seia.org) or Fred DeSanti (fred.desanti@mc2publicaffairs.com) with questions about these comments.

Respectfully submitted,

/s/
David Gahl
Senior Director of State Affairs, Northeast
Solar Energy Industries Association

and

/s/
Fred DeSanti
Executive Director
New Jersey Solar Energy Coalition

Secretary Aida Camacho-Welch
New Jersey Board of Public Utilities
Post Office Box 350
Trenton, New Jersey 08625

January 31, 2020

Re: Comments of Sol Systems on the Staff Straw proposal on Defining the Clean Energy Act of 2018's Statutory Cost Caps

Dear New Jersey Board of Public Utilities and Staff:

On behalf of Sol Systems and our over 3000 New Jersey customers, we commend the New Jersey Board of Public Utilities ("Board") on their efforts to protect the significant value of the legacy Solar Renewable Energy Certificate Program ("SREC"). Sol Systems urges the board to not alter the current structure of the Legacy SREC market. Doing so will cause enormous financial damage to the solar energy industry and immediately place billions of dollars of investment at risk causing large-scale negative impact to communities across New Jersey and put at risk any realistic path to meet the state clean energy goals.

Introduction

Sol Systems respectfully submits the following comments on the above referenced matter and thanks the Board for the opportunity to participate and provide feedback. In addition to these comments Sol Systems supports and formally incorporates the joint comments submitted by The Solar Energy Industries Association (SEIA) and the New Jersey Solar Energy Coalition (NJSEC).

Central to the creation of a viable Class I (Legacy SREC, Transition, Successor, and NJ Class I) program that achieves the State's and the Governor's clean energy objectives, is to maintain the regulatory integrity of the underlying market mechanisms, which have been highly successful to date in facilitating investment to achieve the state's clean energy targets. Critically, the structure of the existing New Jersey Legacy SREC market must be maintained and supported through the application of a viable, transparent and consistent cost cap calculation and process. Accordingly, Sol Systems' comments and recommendations focus on several of the principles laid out in the December 26, 2018 Transition Staff Straw Proposal[1]:

- *Support the continued growth of the solar industry;*
- *Ensure that prior investments retain value;*
- *Meet the Governor's commitment of 50% Class I Renewable Energy Certificates ("RECs") by 2030 and 100% clean energy by 2050;*
- *Provide insight and information to stakeholders through a transparent process for developing the Solar Transition and Successor Program;*
- *Comply fully with the statute, including the implications of the cost cap*

The information and comments we provide below outline best practices for ensuring that the Board adheres to the above principles, while also complying with the mandates laid out in the Clean Energy Act of 2018, S. 2314 / A. 3723 (2018) ("Clean Energy Act"). This is essential to preventing harm to New Jersey's renewable energy

[1] Board of Public Utilities, *New Jersey Solar Transition Staff Straw Proposal ("Straw Proposal") (2018), p.2, available at* https://njcleanenergy.com/files/file/Renewable_Programs/Solar%20Transition%20Straw%20Proposal%20-%202018-12-26%20clean%20(final).pdf

industry and to cost-effectively achieving New Jersey's clean energy targets and maintaining investor confidence in New Jersey's proven and successful renewable portfolio standard ("RPS").

A. Staff requests comments from parties on the following questions regarding the use of headroom in subsequent years:

1. *Should the Board adopt a true-up banking methodology so that any expenditures above or below the Cost Cap in one Energy Year are carried forward to a subsequent year?*

ANSWER: With the passage of S. 4275/A. 6088 (2019) ("Cost Cap Law"), we believe the board now has the authority to develop a true up mechanism and should immediately begin the process for adopting a true up methodology. In any true up mechanism developed by the Board, it is essential that all unspent funds that occur in any specific energy year ("EY") be carried forward in a cumulative fashion and applied to cost cap budget shortfalls through EY2024, as the Cost Cap Law now allows. Cumulatively carrying forward unspent funds will minimize investment risk to the current RPS and adhere to the initial principles set out in the December 26, 2018 Transition Staff Straw Proposal. Adherence to these principles is key to ensure continued growth of the solar industry in New Jersey and to meeting the mandatory 50% Class I standard currently in affect.

2. *Would allowing for banking between Energy Years affect the total ratepayer impact?*

ANSWER: If Board staff means "total" ratepayer impact, no, banking of funds should not have much of an impact. Banking funds between energy years is in line with the goals set out by the New Jersey Legislature and supported by Gov. Murphy in the Clean Energy Act. The Cost Cap Law ensures that in aggregate, the cost caps from EY2019-EY2024, even with banking, will not be exceeded. Sol Systems joins many other industry peers in our support of banking funds between energy years and we believe this is consistent with the legislative intent of the Cost Cap Law and the Clean Energy Act.

3. *Should the Board consider averaging costs over a period in order to more accurately reflect total compliance costs, while smoothing transient effects? How would such an average be constructed?*

ANSWER: It is not clear to us what is meant by "averaging costs over a period in order to more accurately reflect total compliance costs," however, if the Board implies this question to mean, "should it carry forward unspent funds between energy years to smooth out cost cap constraints in particular energy years while not exceeding the cost cap constraints in aggregate over the EY2019-EY2024 period," then yes, we agree that unspent funds in certain years should be used to smooth out cost cap constraints that may occur in future energy years.

4. *Should the Board adopt a true-up banking mechanism that can utilize unspent headroom from previous years as well as anticipated/projected headroom from future years?*

ANSWER: Regarding the utilization of unspent headroom from previous years to future years the answer is yes. Please see answers to questions 1 and 2 above for further explanation. Borrowing anticipated/projected headroom from future years to meet cost cap constraints in earlier years could offer the Board additional flexibility in complying with the cost caps if the Board so chooses to adopt such a borrowing mechanism. The additional flexibility from a borrowing mechanism could come from the fact that over time the costs of the Legacy SREC program will likely decline substantially, particularly as older Legacy SREC qualified systems convert to NJ Class I systems and for other market-driven reasons, which suggest the program is unlikely to trade at the solar alternative compliance rate in outer vintages. For example, as stated in this notice by staff "the Solar Transition Consultant provided different SREC price estimates, with modeled prices falling below $50/MWh sometime between 2027 and 2032. Sol Systems believes it is more important to market integrity and the future of solar growth in New Jersey that a true-up banking mechanism is adopted in relation to unspent headroom in earlier years. That said, adopting a borrowing mechanism alongside a banking mechanism would likely serve to increase investor confidence for all NJ Class I programs.

5. *How should the accounting for such transfers be done?*

ANSWER: If in any energy year, the total costs of compliance with the RPS comes in under that year's cost cap, the savings difference between total cost of compliance and total allowable cost under the cost cap should be banked forward and be eligible for use to satisfy cost cap constraints in future energy years. These savings should be cumulative and rolled over each year until the funds are exhausted or until EY2025, whichever comes first. Sol Systems believes this approach is consistent with the legislative intent of the Cost Cap Law.

For example, if in EY2020 and EY2021, the total costs of RPS compliance came in under the cost cap at $1 million in each year, by EY2022 there would be $2 million that could be allocated towards cost cap excesses. If in EY2022, the RPS exceed the cost cap by $1 million, then $1 million, from the $2 million cumulative existing bank at the start of EY2022, would then remain at the end of EY2022 and be available for use in EY2023 and EY2024.

B. In regard to Cost Cap, Staff requests responses to the following questions:

1. *Do parties agree that Staff has correctly identified the numerator and the denominator?*

ANSWER: Please see answers below.

2. Staff notes that the State's Class I REC programs have resulted in benefits to the citizens of the State of New Jersey, including improved public health, reduction in carbon emissions, and direct financial benefits, such as lower energy and capacity costs.

a. Is it appropriate for the Board to factor these benefits into the Cost Cap Equation?

ANSWER: Yes, there is merit to the idea of including the real and tangible public benefits of in-state solar within the Cost Cap equation when determining if a cost cap has been exceeded. Sol Systems strongly encourages the board to consider the real and tangible public benefits of in-state solar as part of any cost cap solution and urges the Board to gather more information.

b. If so, please comment on which categories of benefits, if any should be included, whether they should be included in the numerator or denominator, and how they should be calculated.

ANSWER: If adopted the real and tangible public benefits of in-state solar should be included as part of the cost cap equation, those benefits should be included in the numerator. For context, one example if from The *District of Columbia's Office of the People's Counsel Value of Solar Study* published in 2017[2]. The study could provide the Board with useful guidance as to what benefits in-state solar may provide to the state of New Jersey as applied to a different market.

If the Board decides to include benefits in the cost cap equation, they should be estimated on a $ per megawatt-hour ("$/MWh") basis and netted from RPS costs in the numerator. Using a $/MWh basis to measure benefits will be the most straightforward way to model how the MWh-penetration of solar in New Jersey delivers these benefits to the State. A $/MWh basis can be easily applied to the production of solar energy in New Jersey each energy year to calculate the benefits that will be netted from the cost figure in the numerator of the Board's cost cap equation.

[2] Melissa Whited et al., Synapse Inc., *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar and Cost-Shifting* (2017), *available at:* https://www.opc-dc.gov/images/pdf/solar/Synapse-DC-Solar-Report-April1217.pdf

Although applied in a different jurisdiction with different circumstances, Washington D.C.'s Office of the People's Counsel Value of Solar Study of Distributed Solar could provide the Board with a useful framework in which to understand how to identify and measure the benefits that are best suited for New Jersey. This report estimated the net value of solar in the District to be in the range of $132.66/MWh to $194.40/MWh in 2015 dollars. Costs and benefits that the study identified were as follows:

Table ES-5. Potential distributed solar costs and benefits

Utility System Impacts	
Cost	Utility Interconnection and Operational Costs
	Increased Utility Administration Costs
Cost or Benefit	Distribution System Costs
	Ancillary Services
Benefit	Avoided Energy
	Avoided Transmission Losses
	Avoided Distribution Losses
	Avoided Transmission Capacity
	Avoided Generation Capacity
	Avoided RPS Compliance Costs
	Avoided Clean Power Plan Compliance Costs
	Avoided Carbon and Criterial Pollutants
	Energy DRIPE
	Capacity DRIPE
	REC SIPE
	Hedge Value
Societal Impacts	
Benefit	Outage Frequency Duration and Breadth
	Social Cost of Carbon

Even if the value of solar in New Jersey turns out to be a fraction of the District of Columbia's estimates, the State's cost cap constraints could be greatly relieved, thereby giving the Board the ability to create enough budget to accommodate all NJ Class I programs without undermining market integrity.

In addition, the Board should take in to account general employment, tax, and economic investment benefits to the State that may not be captured in the benefits identified above. It is could be useful to note that many NJ SREC compliance costs will directly represent savings to residents and businesses that adopt solar energy, which is real money, spent on-the-ground in local NJ communities that not only provide economic benefits to local residents and businesses but also help the state achieves its clean energy targets.

3. *The numerator is defined as the "cost to customers of the Class I Renewable energy requirement."*

ANSWER: The scope of this definition should be expanded to include the benefits of solar.

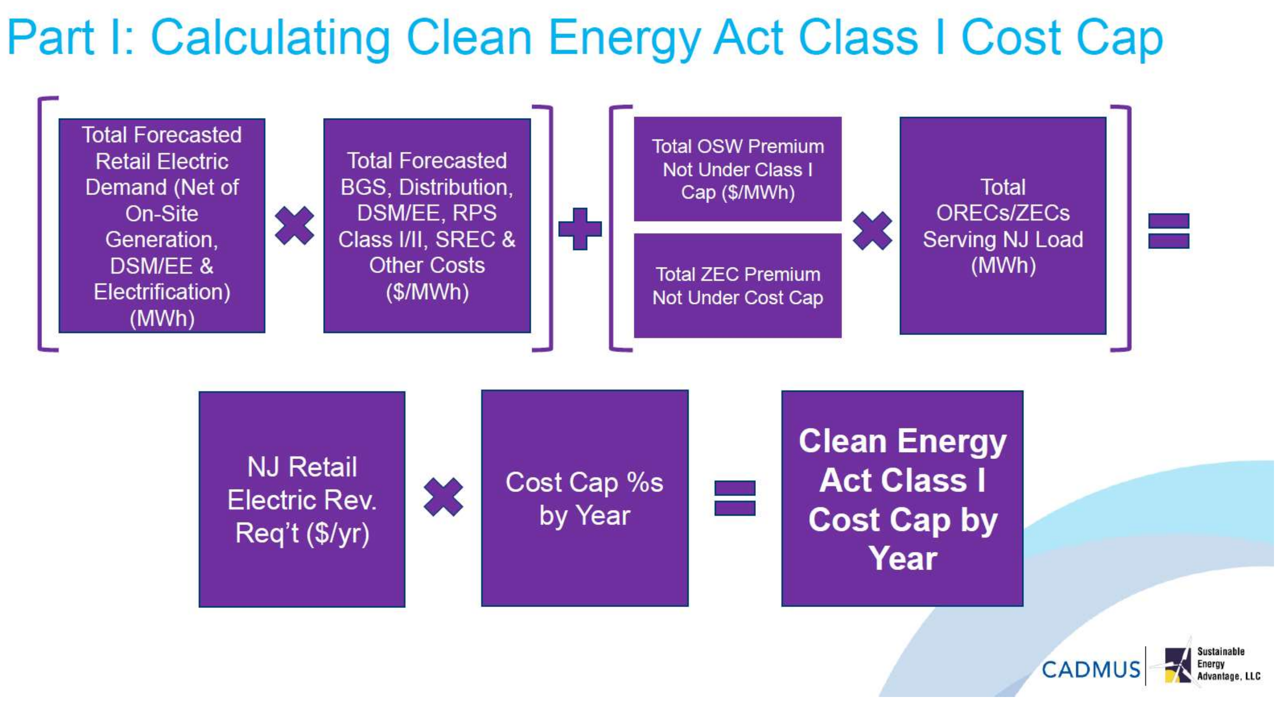
4. *Staff's current practice in calculating clean energy program costs is to aggregate retired quantities from the annual RPS compliance reports of load serving entities and apply the last price recorded in PJM-EIS Generation Attribute Tracking System ("GATS").*

ANSWER: The most accurate methodology for calculating total NJ Class I program costs in each energy year is*: Total Quantity of Retired NJ Class I RECs Per Program Type (MWh) * Weighted Avg. Procurement Cost Per Retired Program REC ($ / MWh). Each NJ Class I program REC retired must be multiplied by its respective NJ Class I program*

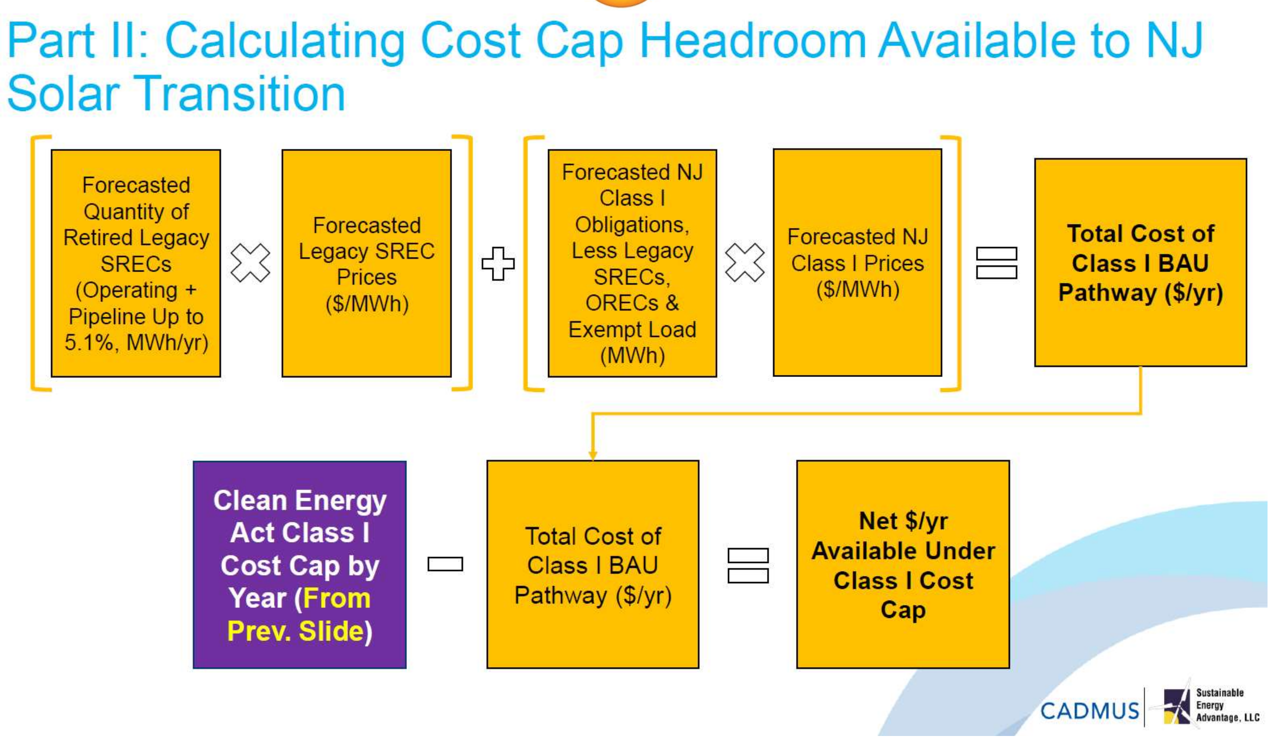
*REC cost and then summed (e.g., [(2 NJ Class I RECs * $5 average = $10) + (2 NJ SRECs * $200 average = $400) = $410])*. Using the "last price recorded" or anything other than a weighted average procurement cost per NJ Class I REC product will lead to inaccurate calculations regarding total program costs.

5. *The denominator of the Cost Cap Equation references "total paid for electricity by all customers in the state."*

Answer to a. through d.: The formula as presented by Sustainable Energy Advantage and Cadmus in the below diagrams on May 2, 2019,[3] is one of the best examples of what components must be included in the denominator to accurately reflect the true "total paid for electricity by all customers in the state." At a minimum, the denominator must include delivery charges, zero emission credits, and offshore wind expenditures to accurately reflect the true amount that New Jersey pays for electricity.



[3] Cadmus & Sustainable Energy Advantage, LLC, State of New Jersey Board of Public Utilities Stakeholder Workshop #1, *Forecast of Clean Energy Act Class I Cost Cap Headroom* (May 2, 2019), pp. 66-67, *available at* https://njcleanenergy.com/files/file/NJBPU%20Cadmus-SEA%20Stakeholder%20Engagement%20Workshop%201%20Full%20Slides.pdf



C. Staff's view that reform of the SREC program will aid in complying with the Cost Cops. Staff requests comments from parties on the following questions regarding how such reforms to the Legacy program could be structure:

1. *Should Staff consider reforms to the SREC market in order to reduce the variability in potential SREC outcomes?*

ANSWER: No, the board must not alter the current structure of the Legacy SREC market. Doing so will cause enormous financial damages to the solar energy industry and place billions of dollars of investment at risk. This will harm the future growth of New Jersey's solar industry and violate multiple Staff Transition Principles. Specifically, the Board must take no action that impacts the "deliverability" of Legacy NJ SRECs or alter the solar alternative compliance payment schedule. The most unacceptable Board actions regarding "reform of the Legacy SREC program" include:

- Implementing a mandatory buy-out mechanism for SRECs in any way, shape, or form
- Retroactively converting SRECs to a feed-in tariff incentive or any other type of fixed-price mechanism
- Lowering the solar alternative compliance payment schedule

2. *Should owners of SREC contracts be required to take part in any restructuring of the program, or should participation be voluntary?*

ANSWER: No. It is essential to the vitality of the legacy SREC program that any restructuring or buy-out mechanism be voluntary.

3. *Should Staff examine moving toward converting SRECs to a fixed price product, or would it be better to look at a lower Alternative Compliance Payment ("ACP") and the institution of a floor price or buyer of last resort?*

ANSWER: No. The Board must not make any changes to the Legacy SREC program that would negatively affect the deliverability of existing SREC contracts or the integrity of the tradable SREC market. Changes that alter the existing architecture of the SREC program would be in direct conflict with existing law[4], would undermine billions of dollars that have been invested in New Jersey and would violate one of the key principles set forth by the Board which set out to maintain the value of the legacy SREC program.

Switching to a mandated fixed-price product or lowering the ACP are both actions that would trigger significant damage to program participants. Such actions would invalidate forward market contracts which provide cashflow to already operational projects in New Jersey and would lead to defaults. Many solar projects hedge their system's future SRECs production in order to finance their projects and businesses, making these types of changes would be extremely detrimental and harmful to the entire industry. ***Therefore, the Board must not take any actions that would impact SREC deliverability or trigger regulatory outs and invalidate forward contracts. Additionally, Sol does not believe that the Board has the statutory authority to lower the ACP***[5].

4. *If Staff were to recommend setting a fixed price for SRECs, how should that price be set?*

ANSWER: No, the Board should not proceed with setting a fixed-SREC price.

5. *If Staff were to look at a lower ACP and buyer of last resort program, how should such a program be structured?*

ANSWER: The Board would need additional statutory authority to lower the ACP. However, even if that authority exists, lowering the ACP would be catastrophic to existing SREC contracts and investments made under the Legacy program and should not be pursued.

If the Board decides to pursue a buyer of last resort program, such a program must adhere to the following design features and principles:

- Participation in the program shall be entirely voluntary at the SREC owners' discretion
- The mechanism must set a buy-out price per vintage
- Any holder of an SREC vintage should be eligible to submit the SREC for delivery and payment (i.e., the buy-mechanism cannot be tied to the project – that is simply not how the project financing of New Jersey solar works)
- The structure of the program must not undermine the tradability or deliverability of SRECs (i.e., all forward contract hedges in place must be allowed to remain valid between over-the-counter participants)

6. *Should the Board consider a "tight collar"? How would such a program be implemented?*

ANSWER: No. The Board should not consider a "tight collar" program. Implementation of a tight collar would undermine the integrity of the SREC program and result in the loss of investments as laid out in previous answers.

7. *Are there other reforms that Staff should consider?*

ANSWER: No.

[4] N.J. Stat. § 48:3-87
[5] N.J. Stat. § 48:3-87 J.

Thank you again for the opportunity to comment on these important matters.

Respectfully submitted

Andrew Williams
Senior Director, Regulatory Affairs, Energy Infrastructure and Markets

vivint.Solar

Kyle Wallace
Manager, Public Policy
Email: kyle.wallace@vivintsolar.com

Attn: Aida Camacho-Welch, Board Secretary
New Jersey Board of Public Utilities
PO Box 350, Trenton, NJ 08625

Vivint Solar's Comments on Treatment of Cost Cap Headroom

Vivint Solar appreciates the opportunity to provide stakeholder comments on the treatment of cost cap headroom. We are grateful that BPU staff are willing to consider alternative approaches to the cost caps in order to ensure a stable and successful solar incentive program. In addition to the comments here, Vivint Solar supports the comments provided by SEIA on this issue.

1. **Should the Board adopt a true-up banking methodology so that any expenditures above or below the Cost Cap in one Energy Year are carried forward to a subsequent year?**

Yes, the Board should adopt a true-up banking methodology for cost cap headroom to ensure continuity of programs and the sustained development of solar projects in the state of New Jersey. It would be logically consistent for the program to bank headroom from an energy year to be used in future years if needed. At the end of the day, the cumulative total for the cost caps equals the maximum allowable for these programs under law. If the total program costs over that same period is lower under the cap amount, then the program should be deemed to be in compliance with the CEA.

The decline in the cost cap from 9% to 7% seems to be a signal that the successor program should be a lower cost to ratepayers than the legacy SREC program. Allowing banking will essentially allow the legacy SREC program to stay below the 9% cost cap cumulative value while the future successor program will be below the 7% cost cap.

2. **Would allowing for banking between Energy Years affect the total ratepayer impact?**

The total allowable ratepayer impact was specified by the Clean Energy Act in the form of the cost caps. The total of each year's cost cap, thus banking between energy years would still not exceed that amount and be in compliance with the law. It is likely that even with banking the total program cost will be well below the total maximum ratepayer cost allowable under the CEA.

3. **Should the Board consider averaging costs over a period in order to more accurately reflect total compliance costs, while smoothing transient effects? How would such an average be constructed?**

Averaging compliance costs and cost caps over a period of years is a potentially workable solution that could ultimately deliver the same results as a banking solution. However, without a clear rationale as to why averaging would be preferable to banking, we would support banking as the solution.

4. **Should the Board adopt a true-up banking mechanism that can utilize unspent headroom from previous years as well as anticipated/projected headroom from future years?**

The Board should be able to utilize unspent headroom from previous years for a current year's program cost. Utilizing projected headroom from future years for a current year could present some challenges and may not be a good public policy choice. Many of the variables surrounding future cost cap calculations and headroom are unknown, including total electricity sales, the price of electricity, rate of PV installations, and the SREC/TREC/successor program incentive values. Estimating each of these inputs adds additional margin of error into the total calculation which could lead to over-estimating available headroom. Another possibility is that additional programs could be developed that would fall into the cost cap, and unless they are specifically exempted. If utilizing historical unspent headroom is sufficient to maintain program availability, we believe that future estimated headroom should not be included. However, should an unseen crisis arise that necessitated borrowing from future years then perhaps it could be necessary to do.

5. **How should the accounting for such transfers be done?**

We defer to the comment made by SEIA on this matter.

Other Comments

We believe that allowing the banking of headroom and having a flat TREC value for the 15-year term is the ideal endpoint. Nowhere in the country is there an incentive structure that would be with extremely low values initially followed by high values in later years. This structure is sure to bring confusion to the market, particularly for less sophisticated companies and customers who will not understand the intricacies of the New Jersey SREC market and legislative constraints. A customer who is expecting roughly a $100/TREC value over 15 years will be very confused as to why they are only getting $30 for the first few years and will likely feel that they were misled about the value of TRECs. Additionally, for homeowners who are looking at payback periods as a compelling point for going solar, if the backloaded TREC schedule delays that payback period it could impact solar adoption. We strongly believe that a fixed TREC value over 15-years is critical for a successful transition program.

Thank you for the opportunity to submit comments and we look forward to continued engagement in this stakeholder process.

Sincerely,

Kyle Wallace
Manager, Public Policy
kyle.wallace@vivintsolar.com