December 18, 2024

Via E-file

Sherri L. Golden
Secretary of the Board
New Jersey Board of Public Utilities
44 South Clinton Ave., 1st Floor
PO Box 350
Trenton, NJ 08625-0350

RE: IN THE MATTER OF THE NEW JERSEY ENERGY STORAGE INCENTIVE PROGRAM. DOCKET NO. QO22080540.

Dear Secretary Golden:

The New Jersey Solar Energy Coalition ("NJSEC") and Solar Energy Industries Association ("SEIA") appreciate the opportunity to provide comments on the New Jersey Board of Public Utilities' ("BPU" or "the Board") 2024 Straw Proposal for the New Jersey Storage Incentive Program ("SIP"). NJSEC and SEIA (together "we" or "our" for the purposes of these comments) represent companies that have installed, or are installing, both solar plus storage assets and stand-alone energy storage devices across the United States and are reflective of their on-the-ground experience.

We thank the Board for the significant work done to date on New Jersey's SIP, including the 2022 SIP Straw Proposal, the 2023 Request for Information ("RFI"), and the 2024 Straw Proposal that is the subject of this comment opportunity. The SIP is being implemented pursuant to the New Jersey Clean Energy Act of 2018 ("CEA"), and while significant and detailed work remains to be done, we are confident that the 2024 Straw Proposal, taken in combination with our below comments, will not only ensure that New Jersey achieves the goals of the SIP, but also the energy storage target set forth for the State in the CEA. Below we provide responses to the stakeholder questions set forth by the Board in this Notice, as well as our general feedback on the 2024 Straw Proposal.

Respectfully submitted,

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NJSEC and SEIA Background

NJSEC was formed to create public policy support for New Jersey's solar industry. NJSEC works in legislative outreach, education, and the development of realistic public policy alternatives that align with the fiscal and social circumstances that are unique to New Jersey. NJSEC members include local and national developers, renewable energy credit market traders and analysts, engineers, and legal and accounting professionals supporting all phases of New Jersey's solar industry.

SEIA is the national trade association for the United States solar industry. As the voice of the industry, SEIA works to support solar as it becomes a mainstream and significant energy source by expanding markets, reducing costs, increasing reliability, removing market barriers, and providing education on the benefits of solar energy and energy storage. SEIA works with its 1,200 member companies and other strategic partners to advocate for policies that create jobs and shape fair market rules that promote competition and the growth of reliable, low-cost solar power. SEIA's member companies range from manufacturers, residential, community solar, commercial, and utility-scale solar developers, installers, construction firms, investment firms, and service providers. SEIA has 50 member companies located in New Jersey with several more national firms also conducting business in the state.

NJSEC and SEIA Key Recommendations

The Straw Proposal is silent on the split between grid supply and distributed storage resources. We seek clarity on this point because this information is critical for project developers and investors to size the potential market, allocate capital and evaluate the economic return of new projects to accelerate energy storage development. We thus encourage the Board to share this information as soon as possible and also reiterate the joint recommendations made by NJSEC, SEIA, Advanced Energy United, and Vote Solar in our September 2023 response to the BPU's RFI pertaining to the development of the SIP, where we proposed that 600 MW of 1.5 GW in the "distributed" bucket be split between 120 MW of behind-the-meter ("BTM") residential storage, 200 MW of BTM-non-residential storage, and 280 MW of front-of-the-meter ("FTM") distribution connected storage.[1] Our additional general comments and recommendations regarding the 2024 Straw Proposal are as follows.

- Greenhouse gas performance-based compensation is not appropriate and will lead to higher bids. Additional information and discussions are necessary to determine whether additional elements related to GHG reductions are needed at a later date.

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[1] See "In the Matter of the New Jersey Storage Incentive Program," Advanced Energy United, New Jersey Solar Energy Coalition, Solar Energy Industry Association, and Vote Solar Joint Comments, New Jersey Board of Public Utilities Docket No. QO22080540. September 2023.

- Incentive levels are too low and must be increased for the distributed storage program.
- The BPU should create a dedicated program to promote FTM, distribution-connected storage that includes a performance-based incentive based on responding to utility grid service needs.
- As an interim measure, the BPU should allow FTM-distribution connected systems 500 kW up to 5 MW to receive the distribution incentive for 2025 and 2026 or until a dedicated FTM-distribution connected program is designed and ready to launch.
- The BPU should launch the distributed storage program in 2025 vs. 2026. The BPU states that the launch is deferred to allow EDCs to develop mechanisms to call resources. We respectfully suggest that this mechanism can and should be developed on a faster timeline, and that the EDCs be directed with more clarity on interim development deadlines such that the program can be launched next year and not delayed further. Additionally, the launch of the upfront incentive for distributed storage is straightforward and should not be delayed while the performance portion of the program is developed. New Jersey should move forward with deploying energy storage in 2025 that will then be able to immediately participate in the performance program when it is ready.
- The BPU should create a dedicated program to promote FTM, distribution-connected storage. Energy storage systems ("ESS") connected to the distribution grid but located in front of customer meters (systems NOT co-located with load) offer several unique benefits to the grid, including: 1) increased hosting capacity for distributed energy resources on the grid; 2) the potential avoid or defer distribution grid investments; 3) local resilience during outages; 4) alleviation of power supply costs for the EDCs; 5) siting near load, minimizing line losses; and 5) in some cases, the ability to bypass the PJM queue, making them much quicker to deploy. The project economics for this class are also unique. On a per MWh basis, these systems are more expensive than transmission-connected ESS. More specifically, these projects incur demand charges and energy charges which can negatively impact project economics and their location on the distribution grid can mean higher siting costs. Additionally, as a smaller class of project, they do not benefit from the economies of scale that can be realized by larger, transmission-connected projects. Under the program as proposed, these systems would be classified within the "Grid Services" category, meaning that they will compete against much larger systems connecting to the transmission grid. Without a unique, dedicated program, this type of system will not be economically viable. New Jersey customers will lose out on the significant potential benefits that these systems can provide.
- We recommend that the BPU design a dedicated program for FTM, distribution connected storage ranging in size from 500 kW up to 20 MW. We strongly recommend that the BPU use a grid-services design that provides compensation for specific services provided to the grid and avoided power supply costs (e.g. ancillary services, forward capacity, energy arbitrage, and resilience). In addition to compensation directly tied to services provided, these systems will require a bridge or top-up payment that could be determined using a gap analysis.
- The BPU should establish a clear timeline so that programs will be launched in a timely manner. We recommend the following timeline.
    - **Q1 2025**: The BPU set the initial MW targets for 2025-2027 for each market segment in the Distributed Storage Program and budget

allocation for the Distributed Storage Program based on current analysis.

  - **Q1 2025**: Open Block 1 (2025) Fixed Incentive with guarantee that Fixed Incentive will ensure that the total incentive level projects receive (Fixed + Performance-Based) is no less than in the values in the straw proposal. Fixed incentives can be adjusted once performance-based payment size is determined. Projects that are approved for the Fixed Incentive should be given conditional approval for the Performance-Base Incentive (where conditional approval means that projects are guaranteed to be eligible and participate in the performance-based incentive as long as they become commercial and meet the requirements to be eligible).
  - **Q2 2025 – Q2 2026**: EDCs develop software capabilities to dispatch assets for the Performance-Based Incentive.
  - **Q2 2025**: EDCs file performance-based incentive rates for each Market Segment and program rules/manuals.
  - **Q3 2025-ongoing basis**: Projects not receiving Fixed Incentive begin applying for conditional approval for Performance-Base Incentives.
  - **Q3 2025**: BPU approves performance based rate and conducts a gap analysis to determine the appropriate Fixed Incentive for Block 1 and future blocks.
  - **Q1 2026**: Start accepting applications for Block 2, projects that are approved for the Fixed Incentive should be guaranteed eligibility to participate in the performance incentive.
  - **Q4 2025-Q2 2026**: Block 1 projects expected to begin COD, with recognition that CODs could extend into 2026/2027 due to interconnection, supply chain, etc.
  - **Q2 2026**: EDC start dispatching for the Performance-Based Incentive Program.
- As an interim measure, the BPU should allow FTM-distribution connected systems 500 kW up to 5 MW to receive the distribution incentive. We recognize that such a "walk-up" program will take time to design and could require a formal avoided costs study and a gap analysis be conducted. In the meantime, we recommend that the Board take interim steps to support this market segment and realize its benefits. While a program is being developed, we recommend the Board allow systems 500kW up to 5 MW that are located in front of the customer meter to receive the same incentives allowed to distributed resources (identified on page 11 of the straw proposal). This would serve as a temporary measure until a dedicated program could be designed.
- The BPU should direct the EDCs to develop specialized retail rates for ESS charging from the grid. ESS should not be charged standard retail rates because their charging and discharging can be coordinated with local grid conditions and power supply cost drivers to avoid costly coincident peaking conditions. Retails rates, including demand charges, are designed to recover costs related to uncontrolled load. Standard retail rates can sink project economics for systems charging from the grid. FTM systems can be operated to minimize costs and maximize revenue for the EDC; and therefore, should be considered marginal load in its own unique rate class. The BPU should require the EDCs to file dedicated rate design proposals for the FTM-distribution connected market segment of ESS. These rates should adhere to three basic principles:

  - Retail rates for ESS should not include demand charges.
  - Rates should include either dynamic price signaling to direct charging away from peak times.
  - Rates should not include any non-bypass able charges because energy will be reinjected back into the grid (to be used by customers locally) rather than used for final end use purposes.
- The Grid Supply incentive should be structured as a long-term tolling agreement rather than a one-time upfront incentive. As currently proposed, the entire incentive for grid supply resources would be provided up front. Structuring the incentive as a long-term (10-15 year) contract – whether a PPA or tolling agreement – would be more beneficial to state objectives as well as allow projects to take full advantage of the ITC. The BPU can look to the tolling agreement structures in California or to public PPAs from other jurisdictions to determine contract terms. Such contracts typically contain certain performance characteristics or allow the EDC or a third- party entity the right to dispatch the battery while requiring the owner to maintain the system and provide for a certain level of reliable capacity. This ensures that assets remain active throughout their useful life and provide useful services to the grid including resource adequacy, renewable integration, and energy arbitrage. In this proposal, the BPU has left open the possibility that a GHG-related performance incentive may be developed over time when more data becomes available. We also support such a concept if and when marginal emissions rates are made available; however, there are contract structures available now that are not related to GHG, but rather to performance for grid support that would spread the incentives out over the life of the asset.
- The planned commercial operations date ("PCOD") and the guaranteed commercial operation date ("GCOD") timelines for Grid Supply resources should be longer to reflect interconnection, permitting, and construction timelines. The proposed regulations in Section 14:8, 14.3(l) state that "The Planned COD must be no more than 550 Calendar Days after the date of execution of the GIA. The Guaranteed COD must be no more than 150 Calendar Days after the Planned COD." Beyond these dates, the Program Administrator may deduct from the project owner's pre-deduction security amount. These timelines are very tight, and not in line with normal construction timelines for large, transmission-connected projects that would qualify for the Grid Supply program. Normal construction timelines would be in the 2–3-year timeframe. The default PCOD timeline should be extended to 730 days. There are many factors outside the control of project developers at this scale; most notably timelines for interconnection agreements to be executed and for make-ready work by the transmission owner to be completed. Queue wait times of more than 4 years, supply chain delays for transformers on the network side of projects, and delays in utility work are all totally outside of the control of project developers, although these delays should qualify as "Force Majeure" (defined in 14:8, 14.2) and allow for extensions for PCOD and GCOD.
- Project revenue for all classes should be distributed over time to incent systems to continue to serve the purposes of the SIP and to take full advantage of federal tax incentives. The incentives identified for the distributed class for projects is expressed as a net present value ("NPV)", without a firm breakdown of what will be available up-front versus paid out over time. The incentives should be spread

out over the life of the asset so that systems are incented to continue to provide benefits to customers and the grid. A sure revenue stream, with a lower upfront incentive allows developers to capitalize the full cost of the system and take the greatest advantage of the federal investment tax credit ("ITC"). Ultimately, facilitating the use of the ITC will drive down program costs for customers. The NPV values in the chart of page 11 seem to indicate that there will be some up-front incentive and some performance-based compensation. We recognize the need to provide for additional financial support beyond the performance compensation mechanism, that additional payment – which would be above and beyond a strictly avoided costs framework – could be provided over time to a system rather than up-front in a lump sum.

- Finally, the BPU should include several elements of a distributed program to fully unlock the potential of this market segment to serve customers and the grid. The suggestions we've included below are common sense best practices in the distributed energy storage space. Leading jurisdictions including Massachusetts, California, Hawaii, and New York have implemented these programmatic design elements in order to lower costs for customers and raise the participation levels in their programs.
    - **Legacy systems**. A performance incentive should be available to already-deployed batteries rather than only new batteries that receive the upfront incentive. Otherwise, BPU will fail to leverage valuable clean capacity that is sitting idly on its grid during times of capacity scarcity or grid stress. If performance incentives are closely tied to avoided power supply costs, they can be used to direct existing asset charge and discharge to help alleviate costs and grid constraints. While the SIP Straw refers to performance payments as an "incentive," it is better to think of performance payments as fair compensation for owners of distributed energy storage systems in exchange for dispatching their systems at opportune times identified by the utilities in order to reduce capacity, energy, grid, and other costs. Thinking of these payments as cost-effective compensation rather than incentives justifies the inclusion of already-deployed batteries, which have significant value to offer the grid and ratepayers. Numerous other battery demand response programs have shown to provide positive Ratepayer Impact Measures (RIM), meaning they provide more benefits than costs to ratepayers. Notable examples included ConnectedSolutions (2.14 RIM)[2] and Green Mountain Power's Powerwall and Bring Your Own Device home battery programs ($3 million saved annually for ratepayers).[3]
    - **Third party aggregation**. BPU should include clear direction to the EDCs to allow and facilitate third-party aggregation of distributed resources. There are many innovative business models and technologies stemming from third party aggregation that can deliver reliable and consistent grid services. If only the EDCs are permitted to aggregate distributed resources, New Jersey runs the risk of locking into one technology or provider that is sub-optimal. BPU should direct the EDCs to allow for in-app or aggregator-led enrollment for the performance incentive portion of the SIP.

[2] See "ConnectedSolutions: A Program Assessment for Massachusetts", on p. 40
[3] "GMP's Request to Expand Customer Access to Cost-Effective Home Energy Storage Through Popular Powerwall and BYOD Battery Programs is Approved". August 18, 2023.

Aggregator-led enrollment is standard in the leading residential battery storage aggregation programs in California, Massachusetts, Connecticut, Puerto Rico, North Carolina, and numerous other states and programs.

- **Device-level telemetry**. BPU should direct the EDCs to allow device-level telemetry for the performance incentive portion of the SIP. Separate dedicated production meters are unnecessary and expensive and should not be required when device-level telemetry, such as smart inverters, is extremely accurate. Device-level telemetry also facilitates the SIP Straw's proposed definition for successfully responding to an event: "either injecting power into the distribution system or by using the energy storage system to reduce the customer's consumption of power from the grid during the call period."
- **Consistent program design**. The Board should provide more specific direction and model tariffs to all the EDCs so that the program design across utilities is consistent. Having different terms, enrollment procedures, and technological considerations across different service territories is problematic and will lead to a fractured market, customer confusion, and could stymie the market as providers must navigate across inconsistencies.
- **Program predictability**. BPU proposes to have small block sizes and frequent revisions to right-size the blocks. This type of uncertainty could result in potential stop-start/boom-bust cycles and make the program more administratively complex as EDCs and developers will need to track many small changes over time. We recommend that a smooth path be laid out from the beginning to facilitate certainty and market investment.

NJSEC and SEIA Responses to Board Questions

In the section below, we provide responses to the questions posed by the Board on the design and implementation of the SIP.

Grid Supply

1. Should a performance incentive based on net avoided emissions be proposed only if PJM or another entity produces a day-ahead, marginal emissions signal?

First, we note that a performance-based component of a program should not be referred to as an incentive, but rather a payment, since it is based on a value that is provided by the resource that is compensated at the value amount. As discussed in our 2022 comments filed on the initial Straw Proposal, we appreciate and support the Board's desire to design a program that ensures the reduction in greenhouse gases, but we do not believe that a performance-based incentive based on net avoided emissions is appropriate.[4] There may be a premium to projects that are dispatched based on

[4] See "In the Matter of the New Jersey Storage Incentive Program," New Jersey Solar Energy Coalition and Solar Energy Industry Association Joint Comments, New Jersey Board of Public Utilities Docket No. QO22080540. December 2022.

emissions signals rather than strictly economic signals. Energy storage devices are entirely controllable, and their carbon emissions profile can be altered; they can be deployed anywhere and can change their charging and discharging behavior at any point in time. A requirement to respond to emissions dispatch signals rather than economic dispatch will impact the other revenue streams available to the project and, thus, the level of compensation needed to provide the emissions benefit.

Instead, we believe that it is appropriate to require that projects track their charging/discharging and emissions data and provide a report after the first three years of the program. At that time, the Board can evaluate whether any changes are necessary to the program in order to ensure carbon benefits. If additional emissions data is made possible at a later time, we would welcome the opportunity to review and provide recommendations based on the release and analysis of that data when it becomes available. Until that time, we should move slowly to avoid creating complex storage operating circumstances and conditions ahead of their time.

2. In the absence of a day-ahead emissions signal, should the SIP institute another form of performance incentive for Grid Supply projects?

We support the development of performance based program components, as we discuss below. We recommend that the BPU design a dedicated program for FTM, distribution connected storage ranging in size from 500 kW up to 10 MW. We strongly recommend that the BPU use a grid-services design that provides compensation for specific services provided to the grid and avoided power supply costs (e.g. ancillary services, forward capacity, energy arbitrage, and resilience). In addition to compensation directly tied to services provided, these systems will require a bridge or top-up payment that could be determined using a gap analysis.

3. What other changes or alternatives would you propose to the GHG Performance Incentive?

Using averaged “net” GHG reduction metrics and the value of carbon reduction, a surrogate discharge incentive value can be broadly calculated. This would provide a “rough justice” incentive that could help spur grid-based project development without the need (as is currently unavailable) to secure the data needed to consider more careful time-based calculations also avoiding significant and burdensome administrative cost both for the state and operating projects.

4. How can the Board mitigate the risk of Grid Supply projects not operating/performing after receiving upfront incentives?

Given the level of incentives provided in this program, projects will have to receive additional revenue streams in order to be financially viable. Those additional revenue streams will ensure that projects are not only operating and performing but are doing so for the benefit of ratepayers (either at the distribution level or at the wholesale market level).

a. **Are the reporting requirements proposed herein sufficient?**

Yes.

b. **Should there be a claw back clause to recover fixed incentive payments from energy storage systems that cease operating shortly after coming online?**

Circumstances of storage systems that cease operating after coming online need to be considered on an individual basis. Clearly, there may be force majeure issues beyond the control of the storage owner / operator that rightfully should be considered, and, conversely, issues of gross negligence in construction or operation also need to be considered. For these reasons, each circumstance should be evaluated independently and referred to the appropriate authority as needed without any "one size fits all" claw back clause.

c. **What should be the metric of success for a specific project be (e.g., discharging power during peak demand periods) for Grid Supply energy storage systems? In other words, what metrics should the Board consider when evaluating operation?**

The availability of metrics for discharging during peak power demands would constitute a clear measure of operating success.

5. Should Grid Supply energy storage projects that replace or demonstrably reduce the run- time of fossil-based peaking plants in overburdened communities be evaluated solely on price or receive additional weight or a preference in competitive solicitations? If additional weight or preference is warranted, please specify how.

As Staff observes in the Straw Proposal, it is difficult to accurately identify localized benefits for grid projects much less calculate a financial value. However, the co-location of grid storage at the site of a fossil peaking facility in an overburdened community will result in the reduction of operating hours of the peaking facility. By calculating the reduction in those peaking MWh produced at a price per ton of avoided GHG generation, an incentive "adder" value can and should be proposed.

Distributed

6. The distributed incentive level breakdown provides varying incentive levels for different sized energy storage systems to account for cost differences. Are the proposed incentive levels appropriate?

We believe overall that the incentive levels outlined in the Straw Proposal for distributed storage are insufficient to incentivize the deployment of energy storage systems. $300/kWh NPV is not 40% of fully installed costs for residential systems. A survey of existing incentive programs and performance-based compensation suggests that energy storage projects above 500 kW receive an upfront incentive between $200-350/kilowatt hour, at least at the start of the program. While there have been some price reductions in energy storage technologies, the incentive levels outlined in the Straw Proposal are not aligned with the cost of building batteries in New Jersey. Furthermore, soft costs related to permitting and building energy storage in New Jersey have not come down given the minimal deployment levels of energy storage to date. As such, a higher incentive, with step downs potentially in the future as costs come down, is needed in a final revised proposal from the Board. The Board should provide further differentiation regarding the level of funding available as a “top-up” or “bridge” payment and the ongoing performance payments that should be tied to avoided costs. As we articulated above, the additional payment does not necessarily need to be given up front but could be spread throughout the life of the project to maximize ITC benefits.

We believe that the current approach of evaluating the upfront incentive and performance compensation bundled together a single $/kWh value is problematic and limiting. First, performance compensation should be determined based on the value that the energy storage systems provide to the grid and all ratepayers and should not be subject to an arbitrary cap based on installed costs. The performance compensation for other energy storage programs, such as ConnectedSolutions in Massachusetts and Energy Storage Solutions in Connecticut, provides higher $/kW compensation while still providing significant net benefits to all ratepayers. The performance compensation in these programs exceeds the $300/kWh combined value included in the Straw Proposal in just a few years.

The method of deciding on performance compensation levels may undercompensate batteries compared to the value that they provide to the grid and to ratepayers. Massachusetts has calculated the value at $275/kW for ConnectedSolutions, which can yield $900+ per dispatch season for some batteries. That value would surpass the BPU’s proposed compensation in less than 5 years, with the potential for these batteries to provide at least 15+ years of value. Additionally, increasing the performance payment to better reflect the avoided costs of dispatching aggregated distributed batteries would send the proper price signal to provide better performance and program participation.

Finally, the economies of scale at the largest size class are not significant enough to warrant such a wide gap in funding between the two smaller size buckets in the largest category. System costs for a 500 kW system are roughly on par with smaller residential systems.

7. Are the incentive adders for OBCs too high, too low, or should the proposed OBC incentive otherwise be modified?

The OBC incentives reflect a 1/3 across the board adder to the target initial incentive rate as presented in table #3. We understand that this metric comes directly from S-225. The 1/3 adder is likely too low to animate the OBC market. Depending on the final performance payment amounts, the upfront incentive likely needs to be a total of between $400-$600/kWh to see meaningful LMI adoption, at least initially. This level of support, with the performance payments, could allow for a low enough battery cost to stimulate the LMI household market.

Connecticut's Energy Storage Solutions Program ("CT ESS") has an explicit program objective of providing 40% of program funding to serve projects serving low-income households & projects located in economically distressed municipalities. Initially, the CT ESS program provided a $200/kWh upfront incentive for standard residential projects, $300/kWh for projects located in distressed municipalities, and $400/kWh for projects serving low-income households. In the first two program years (2022-2023), the program received a total of 186 applications for residential projects and only 17 were either low-income or located in a distressed municipality for a total participation rate of 9%.[5] Starting in 2024, the program increased the incentive levels for both low-income & distressed municipality projects to $450/kWh and $600/kWh respectively) and increased the per project incentive cap to $16,000 or 50% of project costs, whichever is less. This program change has resulted in a significant increase in low-income & distressed municipality participation. In 2024 to date, the program has received 223 applications, of which 88 are low-income, distressed municipality, or both (39% of total applications for the year). This has increased the overall, all-time program participation from 9% to 25% in a single year for single-family projects (if affordable multifamily projects are included, the overall program participation has achieved its target with 41%).[6]

We support a program with the objective of deploying BTM storage to serve Overburdened Communities. The inclusion of a separate capacity block will be important to ensure that the funding can be deployed equitably. An adder to the upfront incentive is the right approach for OBCs, but we do not believe the $100/kWh will necessarily animate the market for low-income households and Overburdened Communities. Reducing the upfront cost is critical for increasing adoption. Additionally, the program should support the deployment of storage for geographically disbursed low-income households that reside outside of OBCs. Households that are willing to provide the necessary income verification or attestation like is utilized for community solar

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[5] The upfront incentive was also capped at $7,500 per project, so not all low-income households were actually able to receive the full $400/kWh value depending on their project costs.

[6] https://energystoragect.com/ess-performance-report/

should be able to claim the OBC adder or a separate, more targeted adder if desired. It would not be fair for non-LMI households in an OBC to be able to receive the adder while LMI households outside of OBCs are excluded from receiving additional support.

LMI household adoption of energy storage is likely to be slower than the standard residential market due to the fact that LMI households are more price sensitive and less able to sacrifice solar savings in order to add a battery to their solar projects. Additionally, due to the older and smaller housing stock, LMI households often are more limited in their ability to add energy storage without additional project costs that are required to make the installation up to code. These forces underscore the critical importance of an increased upfront incentive to make projects viable. A best practice is to provide an incentive for the simpler geographic OBC eligibility, and then a higher, more targeted incentive for LMI households, regardless of whether they are located in an OBC, that are income-verified.

8. How far along are the EDCs in implementing the technology needed to issue calls for the performance incentive portion of the SIP? Will this affect the design of the performance incentive?

We have no information regarding the status of that work and would add that it clearly needs to be a priority.

9. Should the Board require EDCs to implement a designated distributed energy resource management system (DERMS) to effectively manage and dispatch resources across their systems?

Yes, however, this should not be a gating item that delays the storage incentive program, which should be launched at the earliest possible date. Rather than wait for a DERMS system to be fully developed, the program should be implemented as soon as the EDCs can publish an administrative “call mechanism” to jump start the program. Hopefully this can occur in advance of the current target date of 2026. New Jersey is falling far behind other states in the deployment of energy storage, its absence is also further complicating and delaying other collateral energy policies.

Other

10. Do any aspects of this program need to be modified to address NJ Legislature Bills S225/A4893, should the bill be signed into law?

It appears that Staff has relied upon several of the requirements and metrics stated in S-225. We further believe that S-225 will provide the statutory mandate to fully fund the $60 million dollars required for the program. We would, however, make the following recommendations to further amend S-225 before being advanced for further consideration on its way to Governor Murphy's desk:

- All the effective dates within the legislation need to be shortened considerably reflecting the fact that the pilot straw proposal in nearing completion and should be adopted as soon as possible. In addition, specific requirements mandating the EDCs to move forward in FY 2025 to launch both the grid and distributed programs along with the subsequent completion and launch of the DERMS system as soon thereafter as possible.
- The proposed $60 million fund to support this program should be ***<u>dedicated</u>*** from the societal benefits fund by statute in FY 2025 without alteration.
- The requirement that customer sited systems be completed and operational in 18 months (550 days) and grid projects be operational 40 months needs to be appropriately amended to reflect both PJM and EDC delays which are both expected to far exceed these required completion dates.
- Statutory codification will ensure that proposed program will go forward with the imprimatur of both the legislature and the governor.