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

TAHESHA L. WAY
Lt. Governor

BRIAN O. LIPMAN
Director

Via Electronic Mail
Sherri L. Golden Secretary of the Board
44 South Clinton Ave., 1st Floor
PO Box 350
Trenton, NJ 08625-0350
Phone: 609-292-1599
Email: board.secretary@bpu.nj.gov

Re : In the Matter of New Jersey's Distributed Energy Resource Participation in Regional Wholesale Electricity Markets
BPU Docket. No. EO24020116

Dear Secretary Golden:

The Division of Rate Counsel ("Rate Counsel") is pleased to provide these comments to the Board of Public Utilities (the "Board" or "BPU") pursuant to the March 7, 2024 Request for Information, BPU Docket No. EO24020116.

Rate Counsel is generally supportive of distributed energy resource ("DER") participation in wholesale markets through the implementation of Order 2222. This change will likely improve competition, give customers broader choices, and lower rates. Increasing DER participation should also support the reliability and resilience of the electric grid. However, New Jersey ratepayers should not be relied upon to subsidize DER aggregation ("DERA") and aggregator participation in PJM. No costs should be allocated to ratepayers unless and until the benefits to them are proven.

Please see our responses to the RFI below.

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

Questions for New Jersey Electric Distribution Companies

Question 1: How is your EDC preparing for the operation of DERAs within the distribution grid? Please explain any processes already under development and which departments (e.g., Operations, Finance, System Planning) are doing this preparation work.

At this time, Rate Counsel has no comment on this question.

Question 2: Are there any concerns about DERAs' impacts on grid reliability that your EDC believes have not been adequately addressed by PJM or the NJBPU, to this date? Has your company quantified these impacts through risk assessments such as the System Average Interruption Duration Index ("SAIDI") or the System Average Interruption Frequency Index ("SAIFI")?

In order to assess the impacts of DERAs on grid reliability, the Board should require Electric Distribution Companies ("EDCs") to track and report reliability metrics for DERA investments. Different metrics should be used to track both operational reliability (a system's ability to avoid sudden disruptions) and resource adequacy (the system's ability to supply aggregate demand at all times).[1] To measure operational reliability, EDCs should track SAIDI and SAIFI as well as Momentary Average Interruption Frequency Index (MAIFI), Customer Average Interruption Duration Index (CAIDI), Customers Experiencing Multiple Interruptions (CEMI), and Customers Experiencing Long Interruption Duration (CELID) at the system and subsystem level. SAIDI, SAIFI, and MAIFI metrics indicate system performance as a whole, while CAIDI, CEMI, and CELID offer more insight into reliability impacts on customers. It is important that customer-focused impacts are tracked and captured. The Board should require EDCs to quantify CAIDI, CEMI, and CELID impacts.

Additionally, Rate Counsel recommends that the Board require EDCs to track and report resiliency metrics to measure the impact of DERA investments on system resiliency. Resiliency

[1] Natalie Mims Frick, Juan Pablo Carvallo, and Lisa Schwartz (Lawrence Berkeley National Laboratory). "Quantifying grid reliability and resilience impacts of energy efficiency: Examples and opportunities." Dec. 2021.

measures a system's ability to respond and recover from major events (such as severe storms). Resiliency metrics could include SAIDI, SAIFI, MAIFI, CEMI, and CELID measured during major outage events. The Board should use reliability and resiliency metrics when assessing the costs and benefits of DERAs and to help guide decisions about DERA investment.

Question 2a: Are there any suggested solutions to these concerns that your EDC recommends? Have cost and benefit calculations been run on these proposed solutions?

EDCs should be required to conduct benefit-cost analyses ("BCAs") for their proposed solutions. The methods for calculating and assigning benefits should be based on objective, measurable, clear, and specific metrics, and such metrics should be developed in concert with the consumers who ultimately pay those costs.[2] A BCA should account for the costs associated with each DER component, aggregated together, as well as any other related investment costs by the EDC related to the overall solution. The analysis should also include the interactive effects between the DERs in the aggregation. Avoided costs, the magnitude of kWh and kW impacts, and the ability to enable the adoption of other DERs will all be potentially interactive effects. The analysis should also differ from BCAs for non-aggregate DERs as benefits will come from wholesale market participation.

Question 2b: Have probabilities of occurrence been considered and factored into the risk assessments?

At this time, Rate Counsel has no comment on this question.

[2] National Association of State Utility Consumer Advocates. Resolution 2022-01 Urging Development Of Consumer Protection Policies for Interconnection and Electric Transmission and Distribution Planning and Development (2022).

Question 3: Does your EDC have procedures in place to account for and support the addition of new DER technologies into DERAs that may develop between Order No. 2222's implementation and the earliest market participation by DERAs?

At this time, Rate Counsel has no comment on this question.

Question 3a: Are there any technological, cyber security, or software updates that are needed prior to implementation?

The New Jersey Division of Rate Counsel does not have a great deal of insight into the technology EDCs employ. However, any investments or upgrades required for these purposes should be limited in scope. Any cost allocation for these investments or upgrades should also be consistent with traditional cost-causation utility ratemaking principles to ensure that consumers do not pay for what does not benefit them. The developers or owners of DERs should be responsible for any and all updates needed to interconnect DERs to the distribution system.

Question 3b: Are there any retroactive impacts requiring modification to existing interconnection agreements?

At this time, Rate Counsel has no comment on this question.

Question 4: Are there any costs for facilitating the DER aggregation process that your EDC expects it needs to pay as part of Order No. 2222 implementation work such as software updates and administrative support? Would these costs be for operational process technologies or additional business functions? Do you have an estimated level of costs available at this time? If not, what is your company's schedule for developing these cost estimates? What is your envisioned mechanism for cost recovery?

How communication, telemetry, and data management costs associated with implementation of the proposed PJM DER Aggregator Participation Model will be allocated remains unclear, but these costs should not fall to New Jersey ratepayers. Aggregation costs for DERAs include customer acquisition, equipment installation, and operation and maintenance costs associated with developing, deploying, and maintaining the required management software tools for DERA deployment and performance tracking.[3] In particular it is unclear in the PJM compliance filings how costs associated with data collection and telemetry, particularly the required granularity of such data between EDCs and DERA aggregators, should be allocated.

Order 2222 notes that energy resource aggregations can avoid otherwise "significant costs of participating in the organized wholesale electric markets, such as the costs of the necessary metering, telemetry and communication equipment"[4] by participating through an aggregator. For example, aggregation saves these resources the time and resources necessary to learn the market rules and actively submit bids and/or offers into organized wholesale energy markets.[5] However, neither the NOPR nor Order 2222 discuss in detail the cost allocation of the "necessary metering, telemetry and communication equipment." Instead, FERC focuses on the difficulties in modifying bid dispatch model software, metering and telemetry requirements,[6] and the coordination required between ISO/RTO, the DERA aggregator and affected EDCs, remaining silent on the allocation of costs.[7]

In Order 2222, FERC notes prior precedent, where the Commission found "it may also be appropriate, on a case-by-case basis, for distribution utilities to assess a wholesale distribution charge on distributed energy resource aggregators participating in RTO/ISO markets."[8] The Commission appears to implicitly acknowledge that the administrative costs of Order 2222 may be burdensome by including an opt-in mechanism for small EDCs.[9] Some EDCs already

[3] Matsuda-Dunn, Reiko, Laura Leddy, Eliza Hotchkiss, Mukesh Gautam, and Michael Abdelmalak. November 2023. *What Role Do Aggregators Play in Power System Security and Resilience?* National Renewable Energy Laboratory. NREL/CP6A40-85649. https://www.nrel.gov/docs/fy23osti/85649.pdf, page 11.
[4] 172 FERC ¶ 61, 121.
[5] *See Ibid*.
[6] *Ibid*.
[7] *Id*. at ¶¶ 153-156.
[8] *Id*. at ¶¶ 61-62, 247.
[9] EDCs with distribution sales of 4 million MWh or less in the previous fiscal year. *Id*. at ¶¶ 63-65.

recognize potential revenues available from the telemetry and communications needs of DERA aggregators:

> … the distribution utility might be able to provide the necessary data to the RTO/ISO on behalf of the distributed energy resource aggregator via a third-party agreement [and] "the electric distribution companies should be allowed to charge for this service."[10]

Cost allocation for telemetry requirements under Order 2222 remain unclear, although the Commission did acknowledge:

> For example, more granular or precise telemetry may be necessary for a distributed energy resource aggregation that is participating in the frequency regulation market than one that is exclusively providing energy or capacity.[11]

In PJM's February 1, 2022, compliance filing and July 7, 2022, amendment, PJM attempted to satisfy the Order 2222 telemetry requirements for DERs providing different wholesale market services. In rejecting parts of PJM's compliance filing, the Commission noted that:

> PJM has not identified or explained the specific information that the DER Aggregator is required to obtain and verify in coordination with the electric distribution company regarding "compliance with applicable PJM and electric distribution company metering and telemetry requirements."[12]

In its October 26, 2023, motion PJM argued in passing that its proposed DER Aggregator Participation Model limits additional administrative costs by avoiding further DERA participation in wholesale markets but does not explain what it expects those administrative costs will be for DERA aggregators, EDCs, or the ratepayers they serve.[13]

---

[10] 172 FERC ¶¶ 61, 247, 255, Footnote 632; 172 FERC ¶¶ 61, 247, 269.
[11] 172 FERC ¶ 268.
[12] 182 FERC ¶ 61,143 ¶ 223.
[13] PJM, Motion for Leave to Answer and Answer of PJM Interconnection, LLC, FERC Dkt No. ER22-962-005, p. 10 (Oct. 26, 2023).

This lack of clarity raises concerns about cost allocation and the burden of these administrative costs on ratepayers. These costs should be allocated among participating DER-equipped ratepayers and DER aggregators, rather than all ratepayers. Consistent with cost-causation principles, retail customers should only be billed for costs directly related to the distribution service they receive. Retail customers should not be relied upon to subsidize DERA participation in wholesale markets. To the extent that EDCs are permitted to recover costs from ratepayers to facilitate this process, EDCs should not be permitted to receive contemporaneous recovery on those costs. Customers should not be billed for any of these costs unless and until they see the benefits. If EDCs use a clause or surcharge to recover costs immediately, then benefits related to operation and maintenance spending reductions will fall to shareholders rather than ratepayers. Instead, EDCs should not be able to recover costs until ratepayer benefits are proven and realized.

Question 5: Have you evaluated how combining current and planned generation projects will fit into existing projects and plans, and where limitations may exist?

The EDCs (and PJM) should be encouraged to pursue holistic planning opportunities where appropriate to increase the efficiency of infrastructure projects. Proactive planning related to investments for current and future projects will help identify areas of potential overlap. This will enable EDCs to combine projects or delay projects where additional future needs are anticipated.

Question 6: How will your EDC ensure that provisions in PJM's rules pertaining to the double compensation risk for net energy metered DERs are enforced for resources within your company's service territory that will also participate in the wholesale energy markets?

Please refer to Rate Counsel's response to Question 13 below.

Question 7: Are there any misalignments in telemetry, metering, and settlement requirements required for DERAs at PJM and that of resources within your service territory? If so, please explain whether this creates technological limitations for existing resources' ability to *participate. Please detail, if applicable, how your telemetry, metering and settlement requirements differ from PJM's.*

Please refer to Rate Counsel's response to Question 16 below.

Question 7a: Does your EDC have comments on the advanced metering infrastructure (AMI) data interval requirements as it relates to the requirements for authorized communication networks in the wholesale market?

PJM requires that a DER aggregator be responsible for ensuring that a component DER within a DERA has metering equipment that provides integrated hourly kWh values on an EDC account basis. For non-interval metered residential DERAs, DER Aggregators must ensure that a representative sample of component DERs have metering equipment that provides integrated hourly kWh values on an EDC account basis, as set forth in the PJM Manuals.[14]

EDCs in New Jersey have already been rolling out AMI, and the Board has already received extensive feedback from Rate Counsel and other stakeholders on this rollout through individual EDC AMI program petitions, base rate cases, and the Board's generic proceeding in BPU Docket No. EO20110716. AMI that has already been deployed will comply with the requirement to provide hourly meter data. Any additional investments to support the communication of interval data should be justified and paid for by the participating DER ratepayers.

Question 7b: Specifically, how would any modifications be implemented to interval metering devices to bring them into compliance for DERA operation?

Please refer to Rate Counsel's Response to 7a above.

Question 8: Please specify any unique needs or concerns your EDC has in regard to PJM's demand response opt-out provisions. Are there existing limitations that may restrict demand response from joining a DERA within your service territory?

At this time, Rate Counsel has no comment on this question.

[14] PJM, Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER22-962 (February 1, 2022).

Question 9: Are there any aspects of the cybersecurity standards that govern DERAs that your EDC has questions or concerns about? How does your EDC intend to enforce cybersecurity for DERAs that fall within your service territory?

At this time, Rate Counsel has no comment on this question.

Question 9a: Please clarify any details on who in your organization will be responsible for coordinating DERA cybersecurity issues and what procedures you will enact to enforce cybersecurity processes among DER components?

At this time, Rate Counsel has to comment on this question.

Question 10: With New Jersey adopting the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547, specifically 1547-2018, to govern the interconnection and interoperability between inverter based DERs and utility electric power systems, do you anticipate any difficulty in managing aggregations and the individual DER Components that are interconnected? Are there processes or limitations existing today on a DERA's ability to use 1547's capabilities or for allowing individual DERs or microgrids that are disconnected in emergencies to still fulfill their obligations to other resources in the aggregation?

Rate Counsel supported the incorporation of IEEE Standard 1547-2018 and IEEE 1547-2020 into N.J.A.C. 14:8-5 and periodically reviewing updates to IEEE 1547 that may warrant updates to N.J.A.C. 14:8-5 to reflect updated interconnection and interoperability standards.[15] This process should include stakeholders and should be limited to technical changes to IEEE 1547 that should be reflected in N.J.A.C. 14:8-5 such as those provided in Rate Counsel's comments submitted in BPU Docket No. QO21010085. The adoption of IEEE Standard 1547-2018 will improve communication between utilities and DERs and increase overall grid reliability and resiliency. However, Rate Counsel urges the Board to monitor and mitigate the costs to consumers for IEEE 1547-compliant measures. For example, smart inverters, while providing advanced capabilities for DERs, are a costly investment. EDCs should assess the

[15] Gridworks, Smart Inverter Operationalization (SIO) Working Group Report Business Cases and Use Cases (Feb. 1, 2024), https://gridworks.org/wp-content/uploads/2024/02/Smart-Inverter-Operationalization-Working-Group-Report-Feb.1.24.pdf, p. 7. IEEEE Standard 1547 requirements under consideration for revision, expected by 2025 or 2026 include: enhanced communication requirements; storage charging control requirements; load management functionality (host load, EVs, other DER applications); interoperability with other DER components; and DER dispatch scheduling.

payback period for small (<10 kW) residential systems. If installing smart inverters for <10kW DERs would significantly impact system payback periods, Rate Counsel recommends that small residential systems be exempt from smart inverter requirements.[16]

Question 11: Does your EDC have any plans to prepare for Order No. 2222's implementation by means of launching pilot DERA program(s)? If so, please provide details on the pilot program, such as timelines and potential planned phases, and how the pilot will support subsequent DERAs. Please provide justification for why a pilot program is needed prior to full deployment and explain what the anticipated benefits of such a pilot program are.

Please refer to Rate Counsel's response to Question 17 below.

Question 12: Does your EDC have procedures in place in the event that a DERA or a Component DER's Registration review period goes past 60 days and is granted additional time for the review?

At this time, Rate Counsel has no comment on this question.

Questions for All New Jersey Stakeholders

Question 13: Do you have any comments or concerns about the classification of certain resources and their operating profiles as eligible for DERAs? Please state any associated control and/or compensation concerns.

Double Compensation

Order 2222 raised concerns about resources receiving double compensation in both retail and wholesale markets, as some resources have the potential to behave as both a load reducer and supply resource. This will may become more complicated as residential and commercial customers start stacking DERs behind a shared meter (e.g., adding flexible battery storage or bidirectional EVs to existing onsite solar PV systems), making them capable of offering: (1) energy to retail markets; and (2) capacity and ancillary services into the wholesale market. PJM's "must offer" requirement for resources participating in the capacity market means they have to

[16] *See* Ramasamy, et al. "U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks with Minimum Sustainable Price Analysis" National Renewable Energy Laboratory (2023). Accessed: https://www.nrel.gov/solar/market-research-analysis/.

also be available in the day-ahead energy market. This should preclude net-metered resources from participating in the capacity market, because the "must offer requirement could lead to double counting."[17] PJM plans to account for double-counting restrictions for component DERs by accounting for the different services that component DERs will provide in its markets through the registration process, verifying any retail or existing wholesale activities for that resource and restricting wholesale market participation as a DERA as needed.[18] PJM is not reviewing individual states' retail programs that might restrict participation in PJM, but will provide some guidance in PJM manuals. However, a component DER in a net energy metering retail program is unable to provide energy in PJM, and therefore, would not be able to meet PJM's capacity requirement. This results in their inability to participate altogether.[19]

Resources should be strictly prevented from receiving double compensation from wholesale and retail programs for providing the same energy and capacity. This is a key concern for ratepayers that will be managed by PJM. The Board may still want to provide guidance on what retail programs will restrict DERs from participating in PJM through a DERA aside from solar resources involved in net metering.

Energy Efficiency Resources

Energy efficiency ("EE") resources fall within resources that can be included in DERA's according to FERC's Order 2222, but PJM's compliance filing elects to exclude these resources from participation in DERAs. In its compliance filing, PJM pointed out that the DERA participation model should act as a supplemental participation model to enable resources

[17]Guidehouse, "Alternative Aggregated DER Participation Methods for US Grids Are Still Needed," Dec. 7, 2023. Accessed: https://guidehouseinsights.com/-/media/project/navigant-research/whitepaper/alternative-aggregated-der-participation-methods-for-us-grids-are-still-neededpdf.pdf.
[18] PJM, Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER22-962 (Feb. 1, 2022).
[19] *Id*. at 41.

currently unable to participate in the PJM market to do so.[20] EE resources can already participate in existing PJM participation models, and therefore cannot do so through DERAs.

The Board's Order Directing the Utilities to Propose Second Triennium Energy Efficiency and Peak Demand Reduction ("PDR") Programs instructed utilities to sell EE resources into the eligible forward capacity market ("FCM") Base Residual Auctions, because it allows for revenue recovery that helps offset EE and PDR program costs through participation PJM's FCM that benefit New Jersey customers. EDCs have an obligation to sell EE savings into the PJM market, and the Board's Order assumes they will continue receive this compensation from FCM participation.

Meanwhile, PJM has been pushing for reforms that will put up substantial barriers to EE resource participation in the markets and may render state EE programs ineligible for capacity market revenues.[21] The Board should continue to monitor the volatility surrounding EE's treatment in PJM to ensure its own assumptions and orders align with PJM's rules.

Question 14: Do you believe that it is technically feasible to implement Order No. 2222 requirements by PJM's originally proposed 2026 implementation deadline? If not, please explain in detail why not. Are there any actions that PJM or NJBPU could take to make the implementation more efficient and timely?

While the bulk of PJM's proposed amendments become effective February 2, 2026, as to participation of DER Aggregation Resources in the capacity market, a set of tariff revisions became effective July 1, 2023, for the limited purpose of allowing Planned DER Capacity Aggregation Resources to participate in the 2026/2027 Delivery Year BRA.[22] PJM is making efforts to push back this effective date and reduce confusion around the timeline that have so far

---

[20] PJM, Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER22-962 (February 1, 2022).
[21] Leith-Yessian, Devin. "PJM Seeking Expedited Approval of Energy Efficiency Changes." RTO Insider. (Feb 26, 2024). Accessed: https://www.rtoinsider.com/72087-pjm-seeking-expedited-approval-energy-efficiency-changes/.
[22] FERC, Order on Compliance Filing and Rejecting Tariff Revisions, Dockets No. ER22-962-004 and No. ER23-2841-000 (not consolidated), p.1, November 13, 2023.

been rejected by FERC.[23] Given this confusion, Rate Counsel urges the Board to ensure that any procedures to protect customer data and ensure that resources will not receive double compensation, as discussed above, are established as soon as possible.

Grid modernization efforts already encompass upgrades to the grid and interconnection to accommodate new DERs, which should support an efficient implementation of Order 2222. The Grid Modernization Study, prepared for the BPU by Guidehouse Inc. in 2022, lays the groundwork for procedural improvements that will streamline many processes and make adoption of Order No. 2222 more efficient for EDCs.[24] The study discusses strategies to make the interconnection queue more efficient, such as standardizing application software across EDCs to help improve file sharing, reporting practices, and security, and to streamline communication with customers. Establishing a pre-application process and implementing a "first-ready, first-served" application approach will expedite application timelines and prevent queue clogging. Using a cluster study process can also streamline interconnection queues and disperse costs across developers. The study also establishes the need for working groups on numerous topics, including IEEE 1547-2018 assessment and implementation, DERMS rollout, and innovative cost recovery. Staff should work to ensure that, where possible, any efforts to implement the participation of DERAs in PJM that overlap with grid modernization efforts in New Jersey are done in tandem to maximize efficiency. Any discussion of additional subsidies to accommodate additional DERs or DERAs must include a holistic re-evaluation of the current subsidies being provided.

---

[23] *Id*. at 11.
[24] Grid Modernization Study: New Jersey Board of Public Utilities. Guidehouse Inc. August 24, 2022.

Question 15: Do you have any comments or questions about dispute resolution processes between DERAs and utilities?

Any costs associated with the dispute resolution process between DERAs and utilities should not be socialized and borne by consumers, or at a minimum should be strictly limited. Costs should only be socialized when ratepayers receive a direct benefit. However, dispute resolution would only serve EDCs and DERs, making it inappropriate to burden ratepayers. Any costs should be included in other fees associated with the process of DERs entering into an aggregation agreement.

Question 16: How should DER Aggregator performance be monitored/tracked/reported to the public?

Order 2222 implementation raises data privacy concerns related to DER aggregator possession of ratepayer data. The Board should continue to protect consumers' individual proprietary information as DERs enter into aggregations and participate in PJM. Given this new territory of aggregating DER data and using it to engage in regional markets, the Board should maintain the state's strong public policy to clearly prohibit utilities from disclosing, selling, or transferring individual proprietary information, including a customer's energy data to a third party without the affirmative written consent of the customer or by a Board-approved alternative method. (N.J.A.C. 14:4-7.8. See also N.J.S.A. 48:3-85(b).) Similarly, a public utility's use of individual proprietary information is limited to specific uses:

> (a) Initiate, render, bill and collect for such services to the extent otherwise authorized to provide billing and collection services;
> (b) Protect the rights or property of the electric power supplier, gas supplier or public utility; and
> (c) Protect consumers of such services and other electric power suppliers, gas suppliers or electric and gas public utilities from fraudulent, abusive or unlawful use of, or subscription to, such services.
>
> [N.J.S.A. 48:3-85(b)(5).]

To the extent that customer data, including customers who own DERs, must be shared through additional channels to facilitate DERA participation in PJM markets, the Board should strengthen its rules to account for these new processes. Consumers should have clear information about when, how, and where their data will be shared as part of this implementation. Any updates should allow the utility customer to be in control of their individual proprietary information.

Question 17: Should each EDC be required to formally establish pilot programs demonstrating their procedures and performance for DERA integration? Should these pilots be identical/consistent/unique across EDCs?

Pilot programs should not be required for DERA integration. New Jersey may benefit from a gradual rollout to establish effective procedures and best practices. Therefore, it is not clear that a statewide rollout should happen all at once.

If EDCs are ultimately required to formally establish pilot programs for DERA integration, these programs should be viewed as a real-world demonstration of the DERA integration process. EDCs need to prove the benefits of their pilot programs and justify the costs based on empirical data. EDCs should be required to share best practices and conduct a full data-backed BCA before continuing to full deployment or a permanent program for DERA integration.

Question 18: As part of NJBPU's efforts to help implement Order No. 2222 how much technical support from the NJBPU, separate from NJBPU's current Grid Modernization Forum working groups, is desired? Would a statewide stakeholder engagement process, working group, technical conference, or public platform for stakeholder engagement be beneficial?

Stakeholder engagement is an important aspect of implementing new initiatives that will affect consumer rates and energy deployment. Rate Counsel encourages statewide engagement on this issue, but not the creation of new working groups at this time. The Board should conduct any public engagement in an open and transparent way to be accessible to all consumers and other interested parties. The Board should also structure engagement so that it is not administratively burdensome for Board Staff and factors in any limitations on resources experienced by the Board.

Question 19: Are there any specific questions that you have for NJBPU that has not been addressed yet in the FERC Order, PJM's Compliance Filings, or NJBPU's Order No. 2222 outreach efforts?

The Board should require EDCs to consider the impacts of DERA rollout on low-income communities. Such requirements might include low-income bill impact analysis for DERA investments, consideration of low-income prevalence in DERA site evaluation, and creation of a low-income classification when identifying costs and benefits of a project. Tracking this information will enable New Jersey to better understand and mitigate inequitable impacts.

Question 20: Which of the following categories best describes the stakeholder perspective your comments provide?

The New Jersey Division of Rate Counsel is a Government Agency.

Respectfully submitted,

BRIAN O. LIPMAN, DIRECTOR
DIVISION OF RATE COUNSEL

By: /s/ *David Wand*
T. David Wand, Esq.
Deputy Rate Counsel

c: Service List

I/M/O NJ Distributed Energy Resource Participation in Regional Wholesale Electricity Markets
BPU Docket No. EO24020116

SERVICE LIST

Sherri Golden, Secretary
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, NJ 08625
Board.Secretary@bpu.nj.gov

Robert Brabston, Esq.
Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625
Robert.Brabston@bpu.nj.gov

Michael Beck, Esq.
Board of Public Utilities
44 South. Clinton Avenue
P.O. Box 350
Trenton, NJ 08625
Michael.Beck@bpu.nj.gov

Stacy Peterson
Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625
Stacy.Peterson@bpu.nj.gov

Richard Graham Barrett
Board of Public Utilities
44 South Clinton Avenue
P.O. Box 350
Trenton, NJ 08625
Richard.Barrett@bu.nj.gov

Pamela Owen, DAG
Department of Law & Public Safety
Division of Law
R.J. Hughes Justice Complex
25 Market Street, P.O. Box 112
Trenton, NJ 08625
Pamela.Owen@law.njoag.gov

Daren Eppley, DAG
Department of Law & Public Safety
Division of Law
R.J. Hughes Justice Complex
25 Market Street, P.O. Box 112
Trenton, NJ 08625
Daren.Eppley@law.njoag.gov

Brian Lipman
Division of Rate Counsel
140 East Front Street, 4th Fl.
Trenton, NJ 08625
blipman@rpa.nj.gov

T. David Wand, Esq.
Division of Rate Counsel
140 East Front Street, 4th Fl.
Trenton, NJ 08625
dwand@rpa.nj.gov

Maura Caroselli, Esq.
Division of Rate Counsel
140 East Front Street, 4th Fl.
Trenton, NJ 08625
mcaroselli@rpa.nj.gov

Robert Glover, Esq.
Division of Rate Counsel
140 East Front Street, 4th Fl.
Trenton, NJ 08625
rglover@rpa.nj.gov

Debora Layugan
Division of Rate Counsel
140 East Front Street, 4th Fl.
Trenton, NJ 08625
dlayugan@rpa.nj.gov

Patricio Silva
Synapse Energy Economics, Inc.
485 Massachusetts Ave., Suite 2
Cambridge, MA 02139
bbiewald@synapse-energy.com