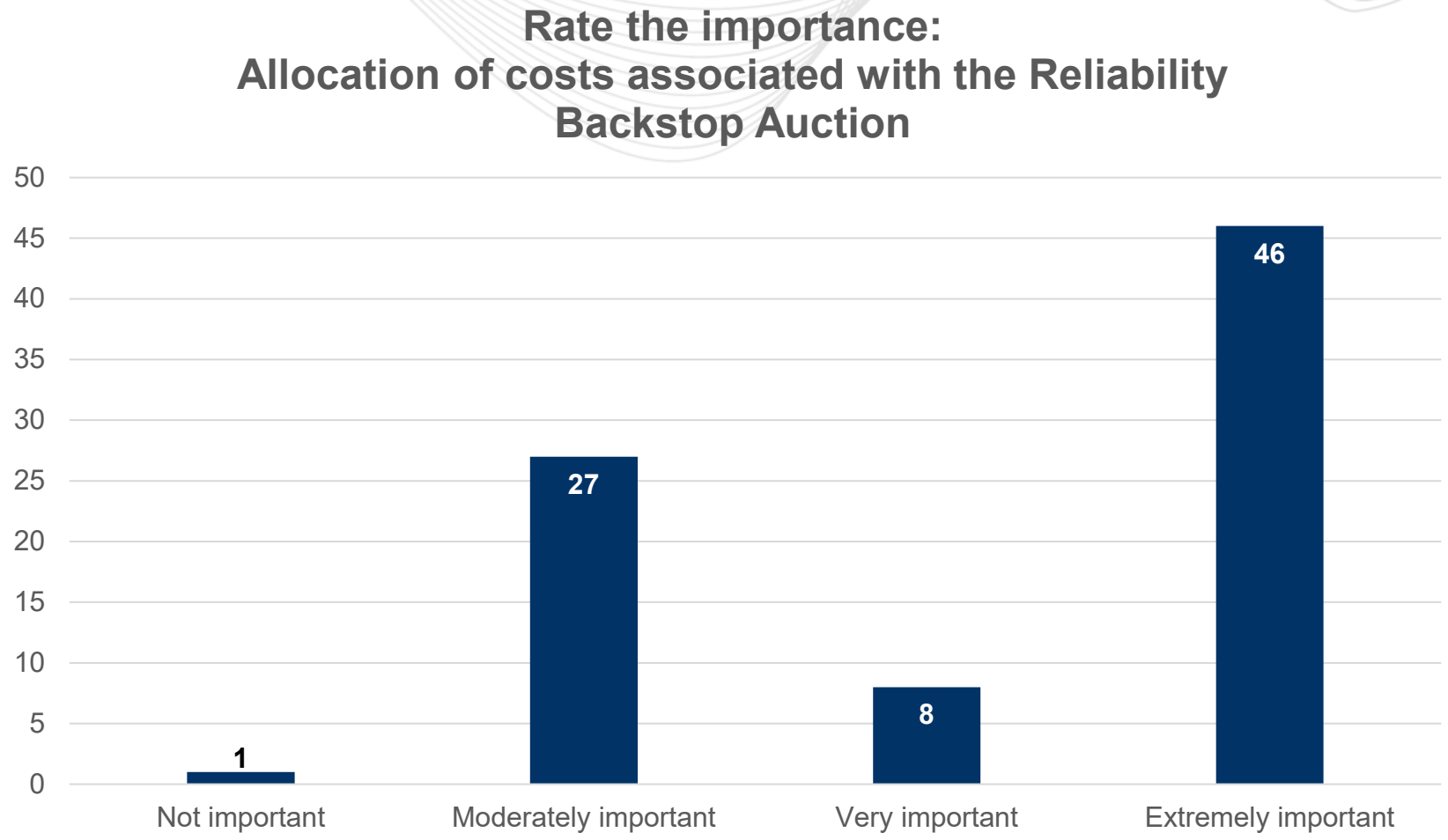
CIFP – Reliability Backstop Procurement Polling Results

Summary of Poll

- Polling questions are available here.
- Poll participation
  - Total Voting Member Responses: 16
  - Total Affiliate Member Responses: 56
  - Non-Member Responses: 10
- Part 1 – Rankings and Yes/No Responses
- Part 2 – Written Comments

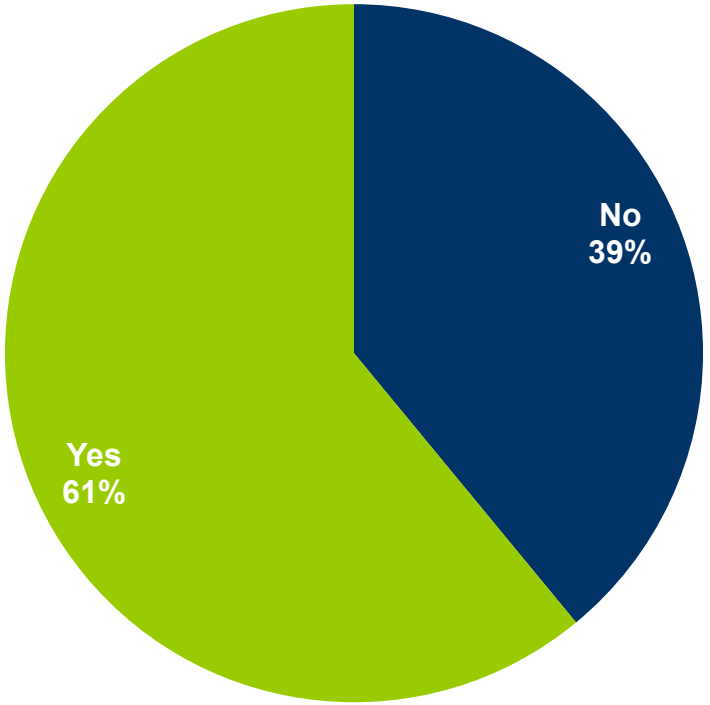
Part 1 – Rankings and Yes/No Responses

Question 1: Cost Allocation



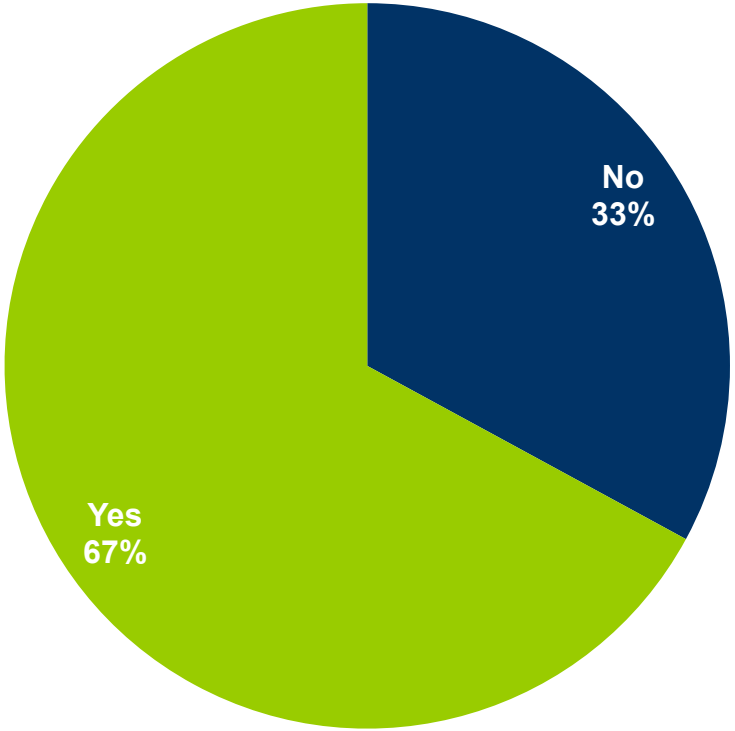
Question 1: Cost Allocation

Can you support PJM allocating costs of the RBP to Electric Distribution Companies (EDCs)?



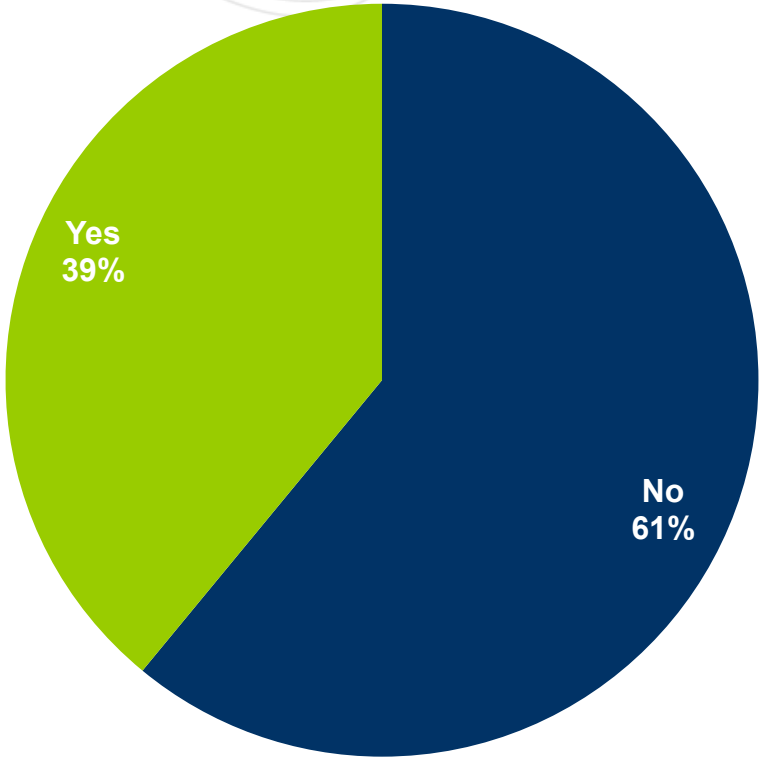
Question 1: Cost Allocation

Can you support PJM allocating costs of the RBP to Load Serving Entities (LSEs) based on information provided by the EDCs in the Delivery Year?

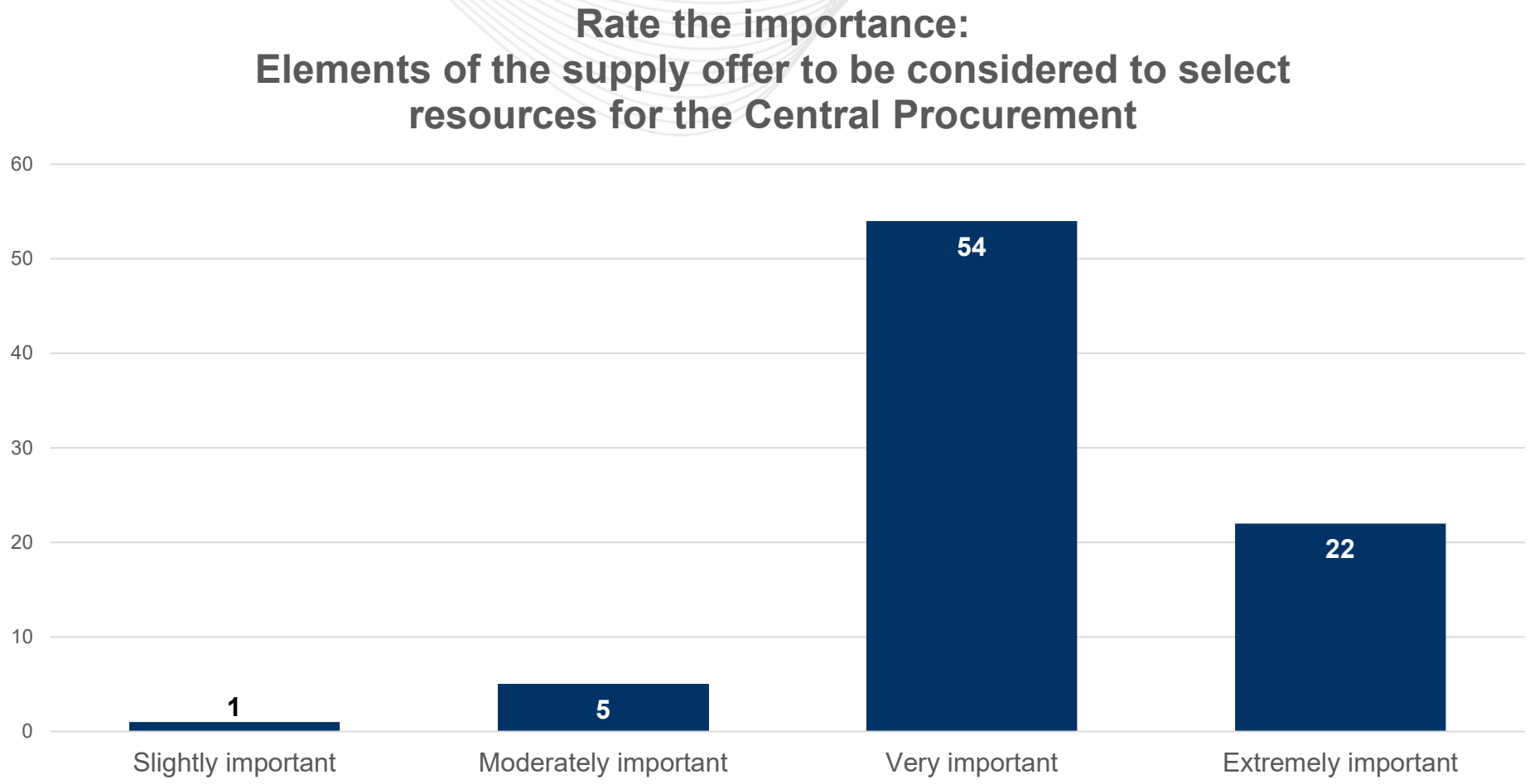


Question 1: Cost Allocation

Can you support PJM allocating costs of the RBP to Transmission Owners (TOs)?

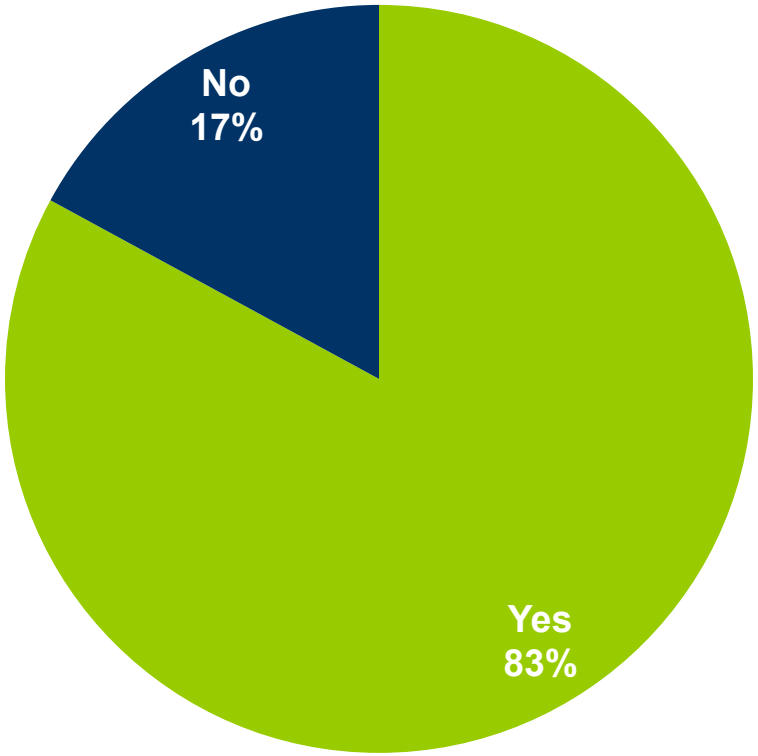


Question 2: Selection Criteria



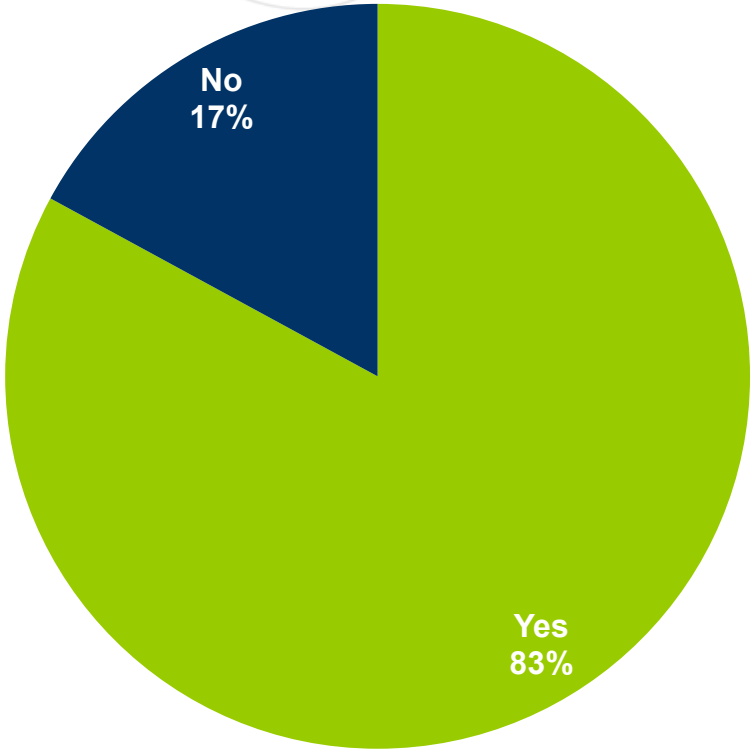
Question 2: Selection Criteria

Can you support selecting resources based on the average cost, $/MW-Day, over the length of the term?



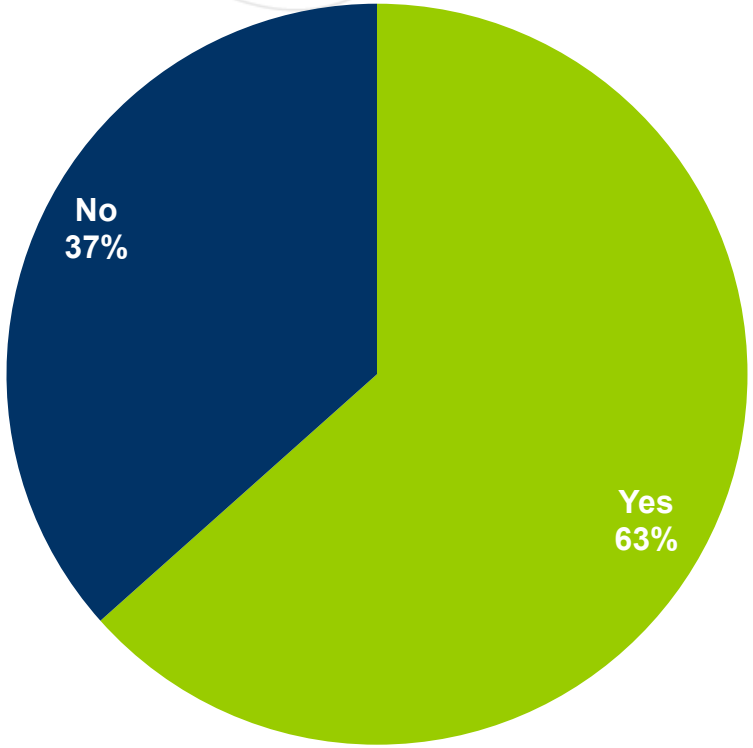
Question 2: Selection Criteria

Can you support selecting resources based on prioritizing Commercial Operation Date?



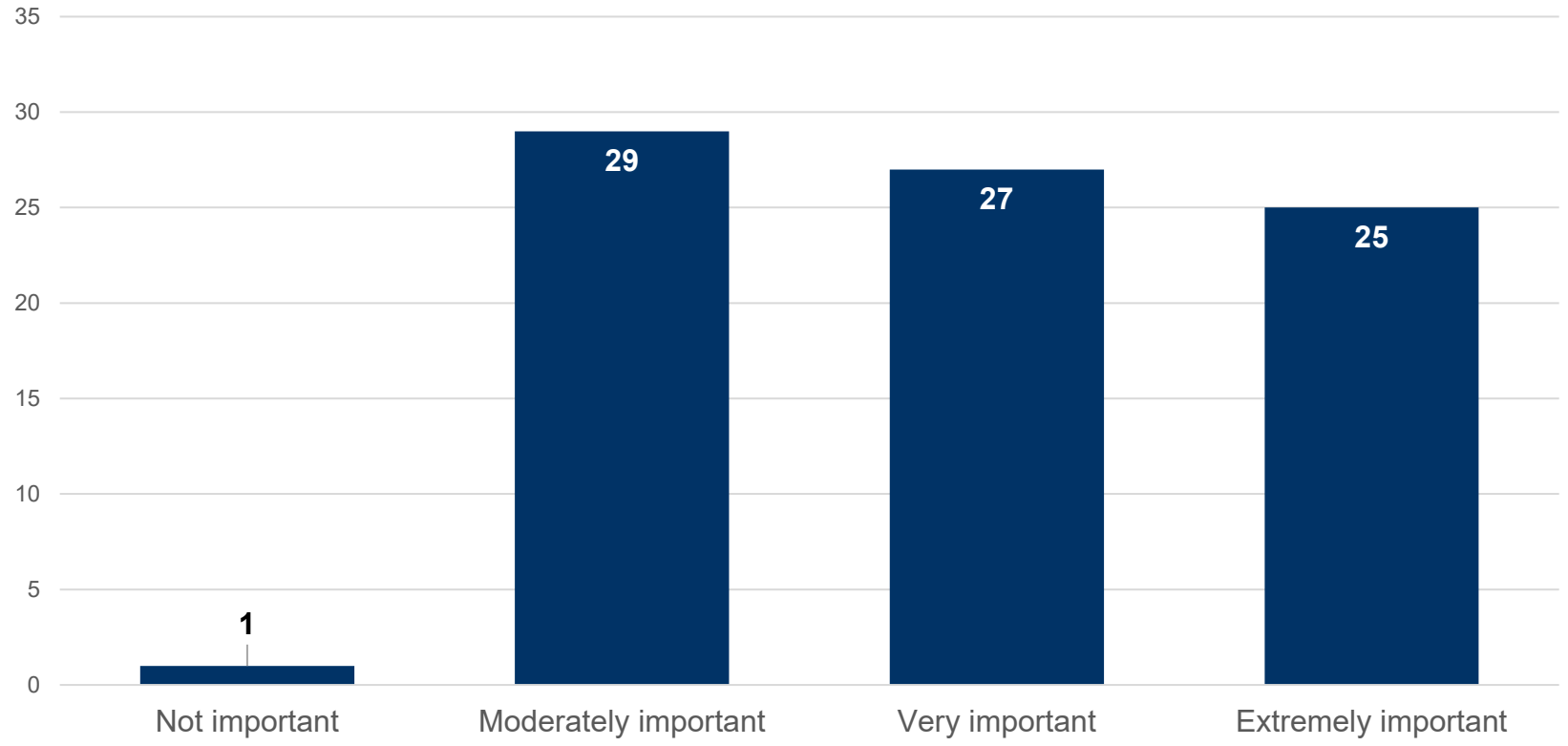
Question 2: Selection Criteria

Can you support selecting resources based on term length?



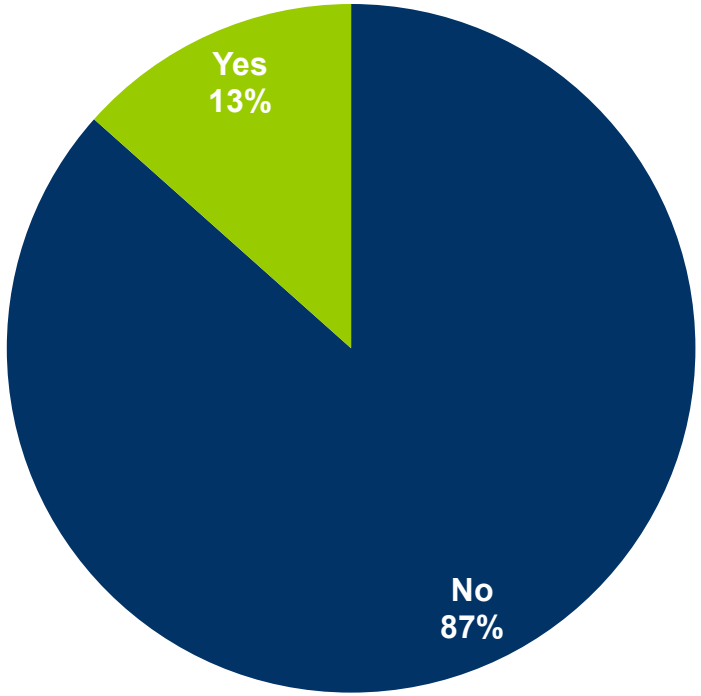
Question 3: Collateral Requirements

Rate the importance:
How does a supply resource reaching COD impact RBP posted collateral



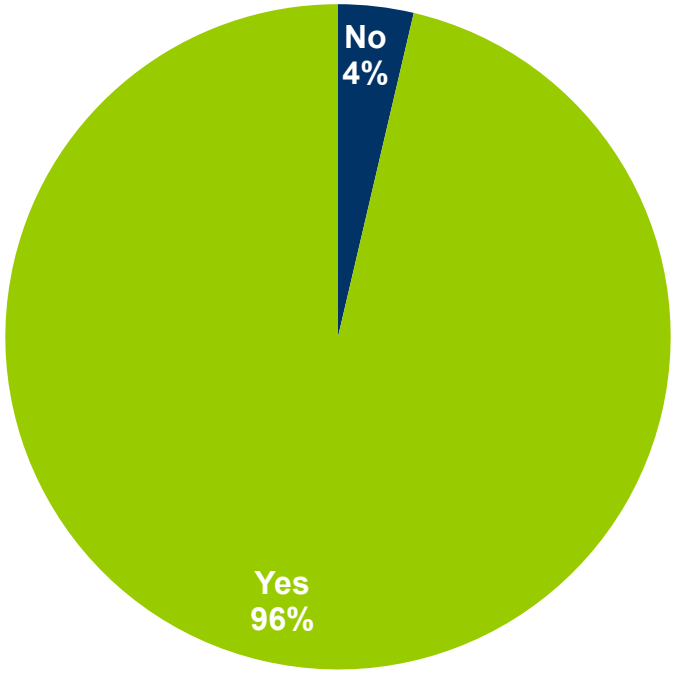
Question 3: Collateral Requirements

Can you support maintaining a static collateral requirement for the term of the contract?



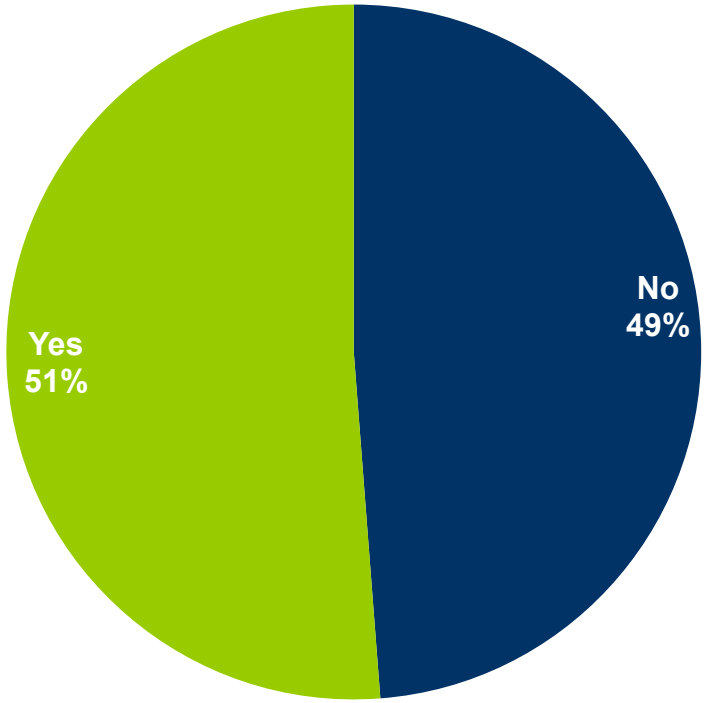
Question 3: Collateral Requirements

Can you support a step-down collateral structure that mirrors the diminishing risk profile over the contract term?

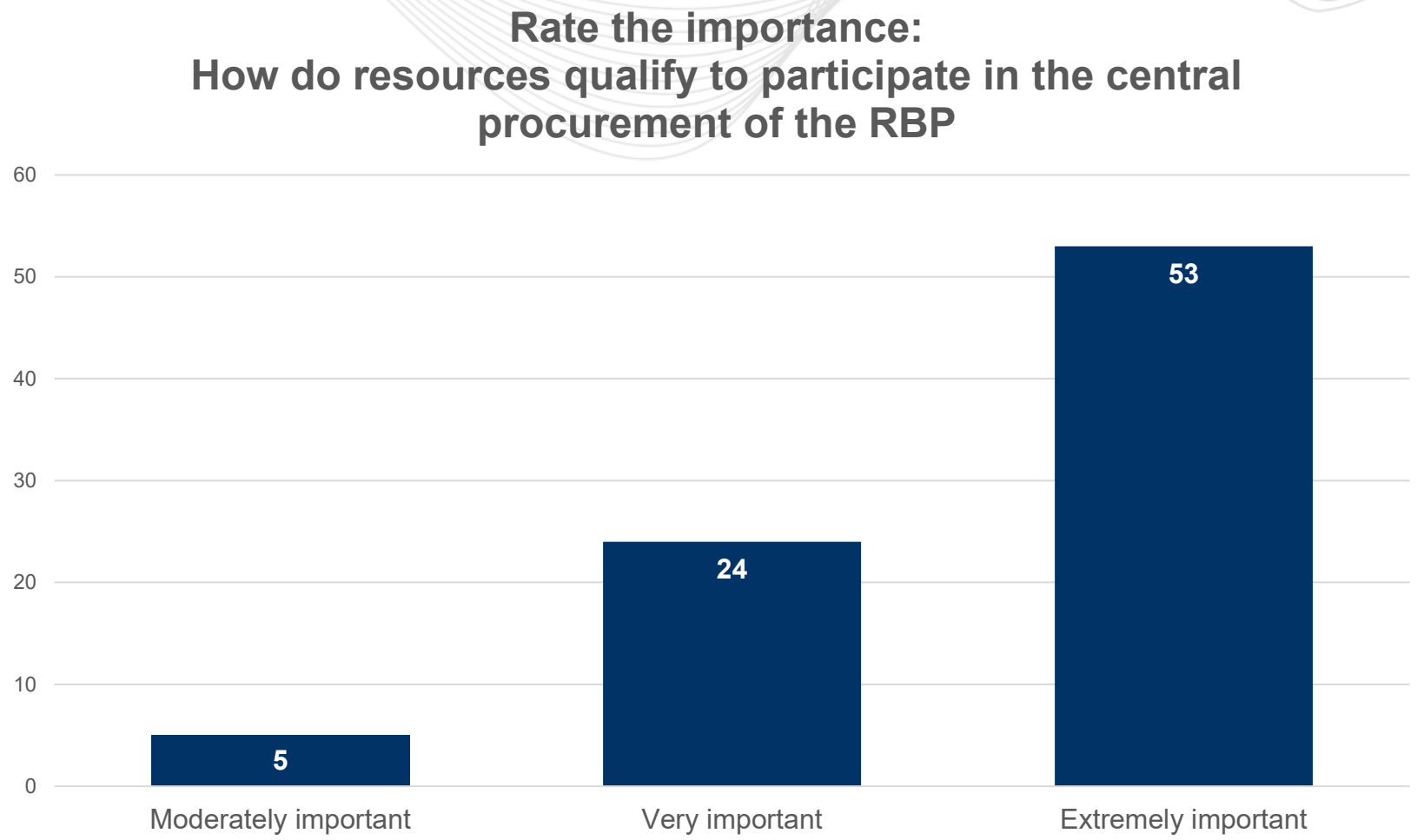


Question 3: Collateral Requirements

Can you support reducing the collateral amount to 50% upon reaching COD for the term of the contract?

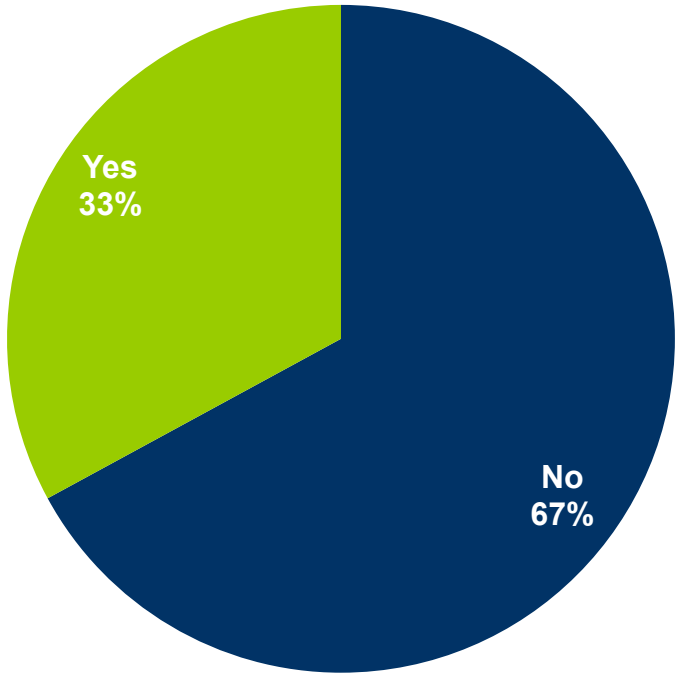


Question 4: Supply Eligibility



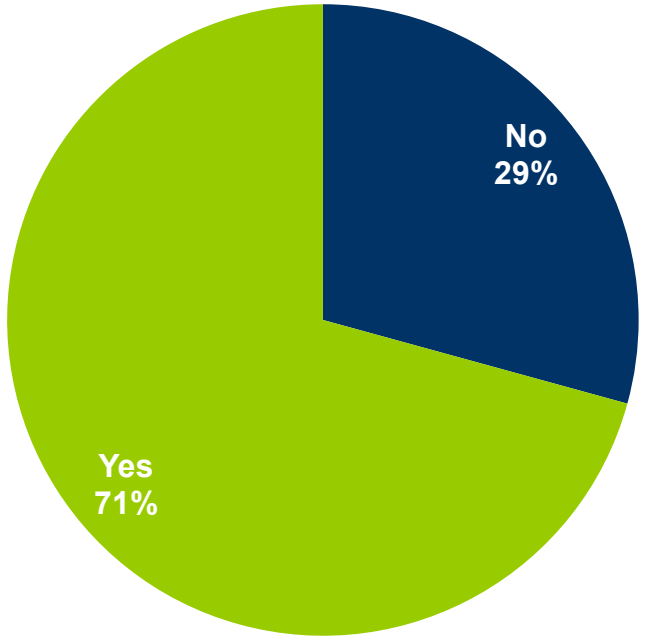
Question 4: Supply Eligibility

Can you support eligibility based on needing to bring new ICAP, new MFO, and new CIRS; and no prior RPM commitment for a future delivery year at the time of the RBP?



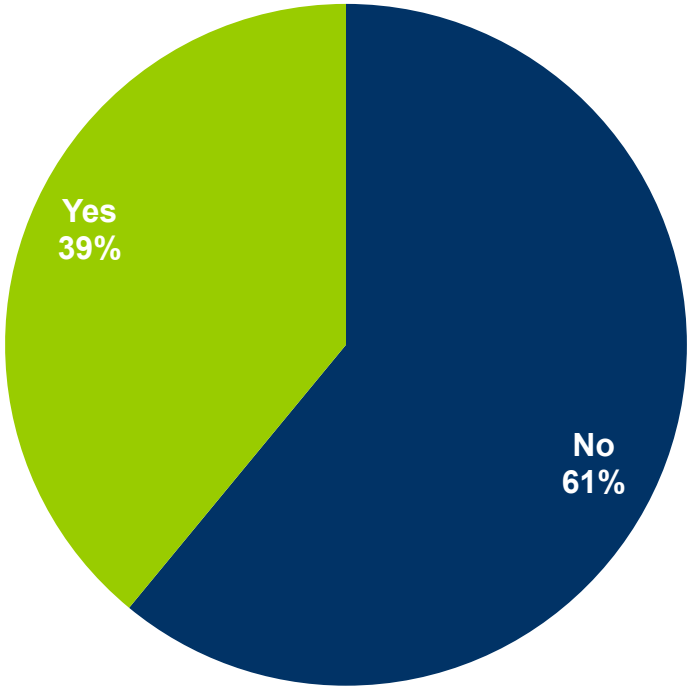
Question 4: Supply Eligibility

Can you support requiring supply resources needing to demonstrate new UCAP, excluding ELCC fluctuations; and no prior RPM commitment for a future delivery year at the time of the RBP to be eligible?

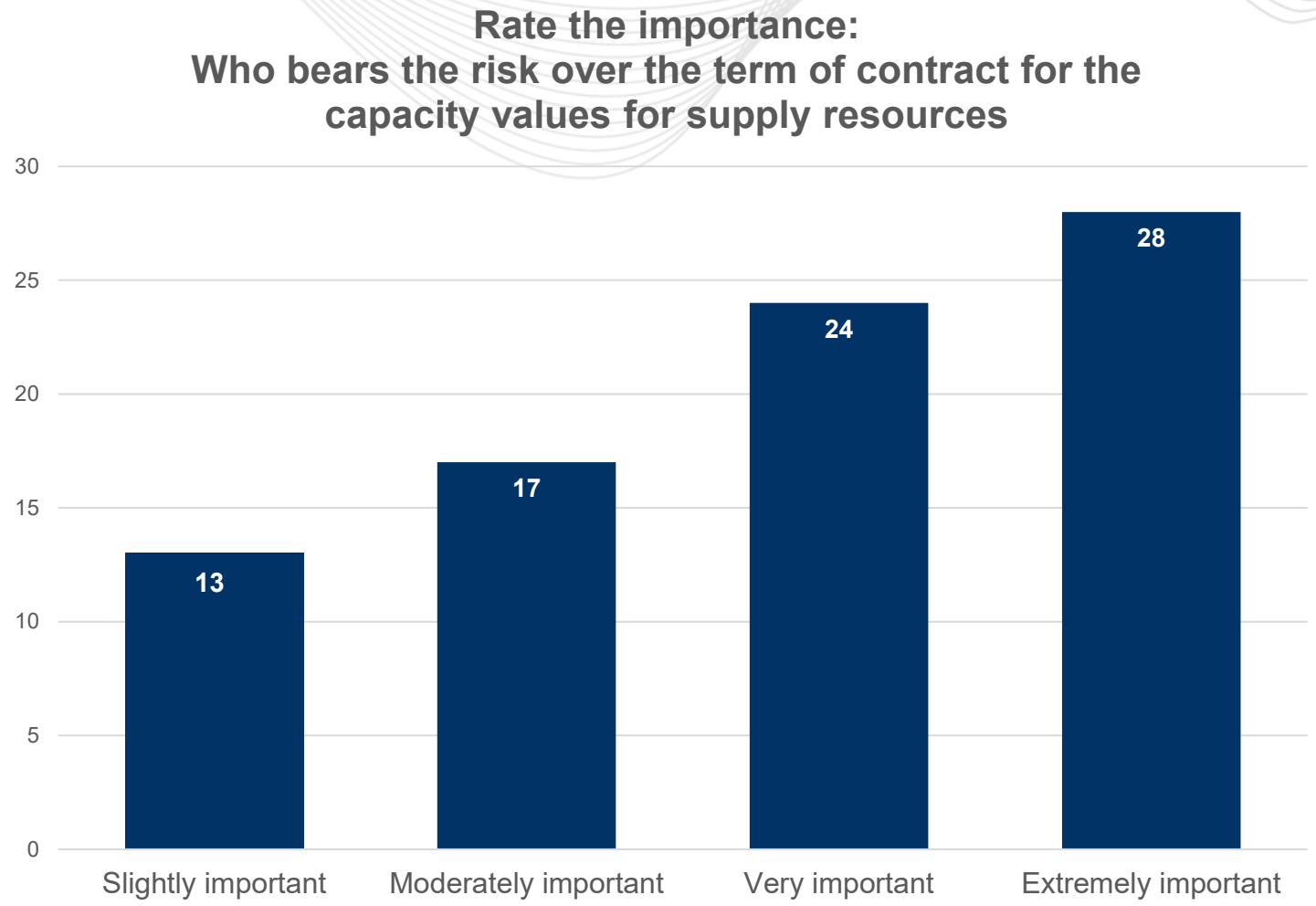


Question 4: Supply Eligibility

Can you support eligibility based on both retaining the existing supply and attracting new resources in the RBP central procurement process?

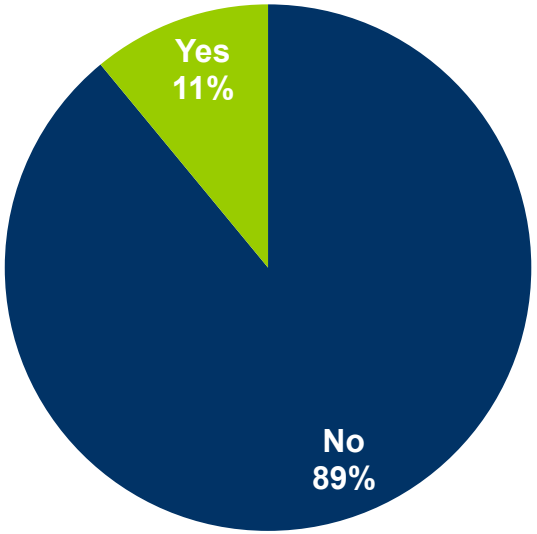


Question 5: ELCC Risk



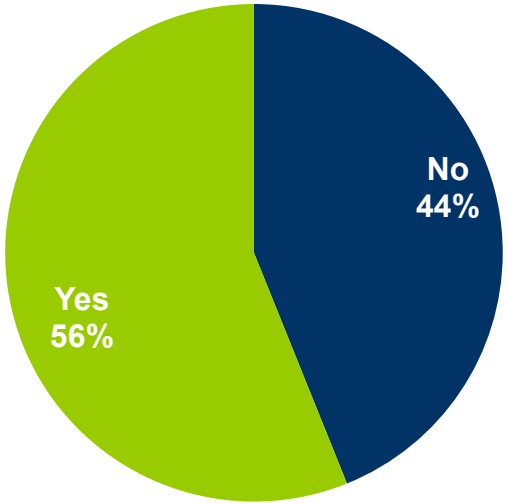
Question 5: ELCC Risk

Can you support a package that the RBP seller (supply) determines the UCAP value over the term of the contract, and is potentially exposed to shortfall charges if unable to meet the UCAP obligation at the time of applicable Delivery Year; ineligible to replace RBP MW?



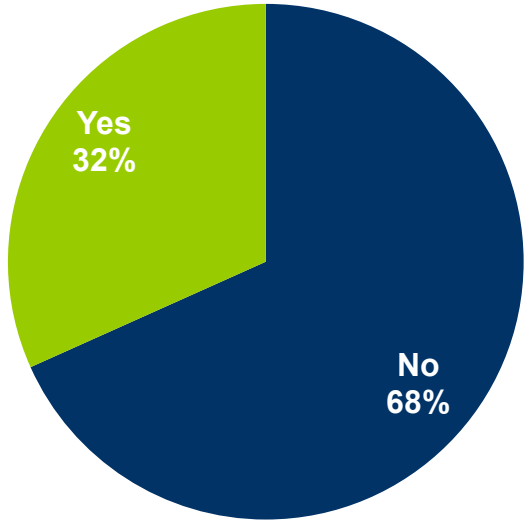
Question 5: ELCC Risk

Can you support a package that the RBP seller (supply) determines the UCAP value over the term of the contract, and is potentially exposed to shortfall charges if unable to meet the UCAP obligation at the time of applicable Delivery Year; eligible to replace RBP MW with eligible MW?



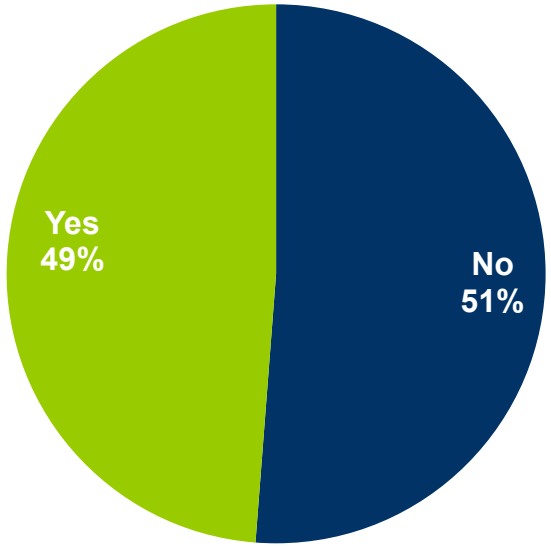
Question 5: ELCC Risk

Can you support a package that the RBP seller (supply) UCAP MW are equal to the ELCC Class Average value over the term of the contract, without being exposed to shortfall charges due to ELCC fluctuations; eligible to replace RBP MW with eligible MW?



Question 5: ELCC Risk

Can you support a package that the RBP seller UCAP MW are one fixed value based on the current preliminary ELCC values over the term of the contract, without being exposed to shortfall charges due to ELCC fluctuations; eligible to replace RBP MW with eligible MW?



Part 2 – Written Comments

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 1 - Cost Allocation	
Company Name	**Can you support PJM allocating costs of the RBP to Electric Distribution Companies (EDCs)? If "no", please explain.**
EDF Renewables	If EDCs don't currently have a way to pass them directly onto the large load, that exposes them to too much risk
Pennsylvania Office of Consumer Advocate	Could support if EDCs and not PJM have the final say in what the amount capacity for the centralized RBP.
CP Energy Marketing (US) Inc.	EDCs are largely pass-through entities and do not control procurement decisions or resource availability. Assigning costs to EDCs weakens cost causation relative to LSE-based approaches.
1. PJM Industrial Customer Coalition	Given the timing constraints, allocating the costs of the RBP to the EDCs is a viable path to facilitate cost allocation to the new qualifying Large Loads that have created the cost. The EDCs have visibility into the new Large Loads that are requesting service and have a direct customer relationship. In many cases, the EDC is (or can be) the LSE. There is accountability to a state regulatory entity (or otherwise in the case of other forms of EDCs) to foster cost allocation based on cost causation principles. To be clear, this approach will require state legislative/regulatory action to ensure that costs are allocated consistently with the pledge. Otherwise, all EDC customers will bear the costs.
1. AES Energy Storage, LLC 2. AES ES Holdings, LLC 3. AES Integrated Energy, LLC 4. AES Laurel Mountain, LLC 5. AES Ohio Generation, LLC 6. AES Solutions Management, LLC 7. Dayton Power & Light Company (The) 8. Great Cove Solar II LLC 9. Great Cove Solar LLC 10. Miami Valley Lighting, LLC 11. sPower Energy Marketing, LLC	Tremous financial liability to the EDC with only a promise to charge the Data Center. In addition, a default by Data Center means EDC or customers are stuck with bill. LDC, LDC as Data Center, token or FRR are all better ideas.
Zenobe Americas	EDCs are not signatories to the Reliability Assurance Agreement, sit outside FERC jurisdiction for most cost-of-service activity, and have no existing tariff role in PJM capacity settlement. The capacity shortfall the RBP is sized to address is driven by data-center growth. Charging EDCs on a MW basis socializes that cost across all distribution-zone load, including residential and small-commercial customers who are not the source of the procurement need.
New Jersey Board of Public Utilities	Staff prefers that costs are allocated as directly as possible to the New Large Loads (NLL) and thus prefers to see costs directed to NLLs themselves, or through LSEs. However, if PJM's initial proposal moves forward and costs from the central procurement are allocated to EDCs, Staff will work to implement it as best as possible to protect our ratepayers and regulated utilities from bearing unnecessary costs and risks from this procurement.
Talen Energy Marketing, LLC	Allocation of costs to EDCs need to be done at the state level. PJM (and FERC) lack jurisdiction under the Federal Power Act to allocate costs directly to the EDCs. The states need to quickly implement their own tariff changes in order for the costs to be allocated at the EDC-level.
Earthjustice	We are concerned that this approach may be legally controversial, and that PJM may lack experience allocating auction costs to EDCs, based on stakeholder input. Avoiding these risks may help the RBP succeed.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	Geronimo supports EDC-based allocation for Phase 2. EDCs have durable territorial franchises and are creditworthy counterparties, unlike competitive retail suppliers or single-purpose LSE entities that could default, resulting in socialized cost across all PJM members. However, this approach must be accompanied by appropriate state-level policy and regulation that effectively transfers all RBP costs to the large loads driving the procurement need. Cost allocation must be politically acceptable to the states, and the EDC-based approach provides the most stable administrative framework for that purpose For Phase 1, the costs should be allocated to the large loads via their bilateral agreements with the generator counterparty.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 1 - Cost Allocation	
PPL Electric Utilities Corporation d/b/a PPL Utilities	-Assigning these roles to Electric Distribution Companies (EDCs) creates significant risks for customers and fails to recognize that there may be a fundamental difference between LSEs and the EDCs who deliver power to customers but may not be the entities responsible for procuring capacity. This is especially true in states that have adopted deregulated/restructured utility models. -There is no mechanism that allows EDCs to allocate procurement costs to large load customers (default is allocation to customers across all customer classes.) -Data centers in states with restructured utility models are not expected to forego opportunities to shop for supply, and EDCs can't require data centers to take default supply service from the EDC. -State law, in restructured states, prohibits EDCs from taking on commodity risk. -If this responsibility is on the EDCs, the significant credit/assurance expenses associated with long-term commitment eventually falls on customers. EDCs will need mitigate these risks and potentially adjust PJM's initial procurement target for a zone to zero in order to avoid stranded costs. -PJM's proposal to assign the role of holding contracts procured through the RBP to EDCs effectively creates a secondary capacity market that puts EDCs in the position of buying and selling capacity outside of the PJM RPM structure (i.e., the capacity market). If implemented, this will further blur the lines between deregulated wholesale energy supply markets and state-regulated delivery of electricity. This outcome is particularly concerning in states with restructured utility models.
1. NRDC 2. Sustainable FERC Project	The "yes" only applies if the EDCs are placing their RBP bids with the approval of their RERRA. There should be no allocation of costs to an entity with resource to ratepayers without regulator oversight.
Voltus, Inc.	Assigning the costs directly to the large loads, or to their LSE representatives, will most effectively ensure cost allocation to those entities that benefit, protecting other ratepayers from pass-through allocations.
1. Old Dominion Electric Cooperative 2. TEC Trading, Inc.	The EDC are not the beneficiary of these transactions and should not be wearing the financial and contracting risk for a long term capacity commitment extending 20 years
1. Virginia Electric & Power Company 2. Dominion Energy Generation Marketing, Inc 3. Dominion Energy South Carolina, Inc. 4. Eastern Shore Solar LLC 5. Greensville County Solar Project, LLC 6. Hardin Solar Energy LLC 7. Southampton Solar LLC 8. Summit Farms Solar, LLC 9. TWE Myrtle Solar Project, LLC 10. Virginia Solar 2017 Projects LLC 11. Wilkinson Solar LLC	The current Manual 19 Large Load Adjustment process looks to EDCs — who typically are not responsible for supplying capacity — creating a "skin in the game" gap. PJM's RBP proposal addresses this but unnecessarily places EDCs in a middle-man role, requiring them to obtain commercially sensitive information and creating potential conflicts of interest.
Company Name	**Can you support PJM allocating costs of the RBP to Load Serving Entities (LSEs) based on information provided by the EDCs in the Delivery Year? If "no", please explain.**
Pennsylvania Office of Consumer Advocate	Could support if the LSEs and not PJM have the final say in what the amount capacity for the centralized RBP.
PJM Industrial Customer Coalition	This could be a valid pathway, assuming that there is a distinct "ticket" associated with the new Large Load and credit risks can be assuaged such that the costs do not become socialized to other customers (e.g., in the event of bankruptcy, etc.). It also requires the new Large Load to contract with an LSE many years in advance of energization, which may not be the case presently.
1. Constellation Energy Generation, LLC 2. Constellation NewEnergy, Inc. 3. Calpine Bethlehem, LLC 4. Calpine Energy Services, L.P. 5. Calpine Energy Solutions, LLC 6. Handsome Lake Energy, LLC 7. Champion Energy Marketing LLC 8. Champion Energy Services, LLC 9. Champion Energy, LLC 10. North American Power and Gas, LLC 11. Calvert Cliffs Nuclear Power Plant, LLC 12. Calpine Mid Atlantic Marketing, LLC	EDCs control the physical interconnection and are responsible for reporting the large load request to PJM as part of the Load forecasting process. A large load may shop for supply amongst several LSE both before and after its initial interconnect. Therefore, the allocation mechanism should maintain a close tie to the EDCs for practical implementation.
New Jersey Board of Public Utilities	Staff prefers that costs are allocated directly to NLLs. However, Staff acknowledges the practical considerations with this approach, primarily that not all NLLs may have a paired LSE at this time. We would support an approach in which NLLs are their own LSEs.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 1 - Cost Allocation	
1. NRG Business Marketing LLC 2. Helix Ironwood, LLC 3. Midwest Generation, LLC 4. NRG Curtailment Solutions, Inc. 5. Direct Energy Business, LLC 6. Energy Plus Holdings LLC 7. Green Mountain Energy Company 8. Reliant Energy Northeast LLC 9. Stream Energy Pennsylvania, LLC 10. Xoom Energy, LLC	The companies could support allocation to LSEs if the allocation followed the meter(s) associated with the large load and the LSEs that serve those meters. This approach must have an equitable way to address situations where load for which resources were procured does not materialize and those resource costs still need to be allocated. (This situation is applies to all allocation methodologies.)
Talen Energy Marketing, LLC	Talen does not agree that all LSEs should be subject to cost allocation. Instead, Talen agrees with allocating costs to the FERC-jurisdictional utilities in the locations that the large loads are located (i.e., the entity that is physically connecting the load to the grid).
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	For Phase 2, allocation to LSEs is far less effective than allocation to the EDCs. In deregulated states, loads can switch LSEs, which introduces instability into any LSE-based cost allocation over the 15 year contract terms contemplated by the RBP. An LSE serving a large load today may not be serving that load in five years, creating stranded cost and credit risk that undermines the long-term certainty this procurement requires. In regulated states where the EDC and LSE are the same entity, this distinction is less meaningful, yet RBP design must work across PJM's full footprint, including competitive retail markets. We believe EDC-based allocation is the more stable and administrable approach: EDCs have a durable territorial franchise and can work with their state commissions to determine how costs are ultimately passed through to LSEs or directly to the large loads driving demand. The EDC and the state are better positioned to manage potential LSE defaults and load-switching over the life of the contract. That said, our preferred approach is direct allocation to the large loads themselves, which avoids the EDC-versus-LSE complexity entirely and most directly connects costs to the entities whose demand growth is driving the need for the RBP.
PPL Electric Utilities Corporation d/b/a PPL Utilities	-Load-Serving Entities (LSEs) are the right entities to procure RBP supply on behalf of customers and, through retail supply contracts, pass the costs of procurement to large load customers. This is the only way to ensure that other ratepayers are insulated from these costs. LSEs are the entities that participate in the wholesale market to procure capacity for load within PJM. -LSEs are the right entity for assignment of RBP costs however, more clarity is needed as to the information PJM envisions provided by Electric Distribution Companies I(EDCs) in this poll question. PJM should obtain RBP capacity procurement information directly from LSEs and Large Loads through the creation of a registry as proposed by several utilities in the PJM RBP discussions. -Support cost allocation to LSEs with strong preference for this to be accomplished through bilateral contracts between LSEs and the large loads. -It is not appropriate to shift the risks and costs of wholesale market procurement to EDCs, especially those in states with restructured utility models.
1. NRDC 2. Sustainable FERC Project	Similar to above, EDC determination of RBP quantities must go through their RERRA, Given that, some kind of capacity-like cost allocation to LSEs is reasonable. Again, retail regulators must remain in charge of this cost allocation, as they are today with their control over PLCs.
Voltus, Inc.	As noted above, assigning the costs directly to the large loads avoids the need for more complicated pass-throughs while protecting other ratepayers. However, LSEs are best-positioned of the administrative/supply entities (TOs, EDCs, LSEs) to allocate costs to large loads. LLs have direct relationships with their LSEs, from whom they need to attain electric service. The incentives are aligned: LSEs gain financially from serving new LLs, and so can reasonably carry the obligation of ensuring that incremental capacity costs associated with serving those LLs are correctly allocated to those LLs in alignment with the WH+PJM Governors' directives, the Board's principles, and the pledges made by the LLs themselves.
1. Old Dominion Electric Cooperative 2. TEC Trading, Inc.	Yes. These entities need to be committing if they want to engage in a 20 year contract
Company Name	**Can you support PJM allocating costs of the RBP to Transmission Owners (TOs)? If "no", please explain.**
Pennsylvania Office of Consumer Advocate	Could support if the TOs and not PJM have the final say in what the amount capacity for the centralized RBP.
CP Energy Marketing (US) Inc.	TO allocation misaligns responsibility and incentives.
PJM Industrial Customer Coalition	We are concerned that there may be regulatory gaps with respect to allocating the RBP costs to TOs. Would FERC or state commissions then decide retail cost allocation? As a note, some TOs have attachment M-2s as part of the PJM tariff where TOs allocate capacity and transmission costs to retail customers, with varying degrees of regulatory oversight.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 1 - Cost Allocation	
1. AES Energy Storage, LLC 2. AES ES Holdings, LLC 3. AES Integrated Energy, LLC 4. AES Laurel Mountain, LLC 5. AES Ohio Generation, LLC 6. AES Solutions Management, LLC 7. Dayton Power & Light Company (The) 8. Great Cove Solar II LLC 9. Great Cove Solar LLC 10. Miami Valley Lighting, LLC 11. sPower Energy Marketing, LLC	Same answer as LDC.
Zenobe Americas	The RBP is a capacity procurement, not a transmission investment, and TO revenue requirements are set through separate FERC-jurisdictional rate filings that do not contemplate capacity market cost recovery. Routing RBP costs through TOs would (i) create a cross-subsidy from transmission ratepayers to capacity buyers, (ii) blur the line between transmission and capacity cost allocation that PJM has worked carefully to keep distinct, and (iii) provide no link to cost-causation as TOs are not the source of the data-center-driven shortfall.
1. Constellation Energy Generation, LLC 2. Constellation NewEnergy, Inc. 3. Calpine Bethlehem, LLC 4. Calpine Energy Services, L.P. 5. Calpine Energy Solutions, LLC 6. Handsome Lake Energy, LLC 7. Champion Energy Marketing LLC 8. Champion Energy Services, LLC 9. Champion Energy, LLC 10. North American Power and Gas, LLC 11. Calvert Cliffs Nuclear Power Plant, LLC 12. Calpine Mid Atlantic Marketing, LLC	EDC control the physical interconnection and are responsible for reporting the large load request to PJM as part of the Load forecasting process.
New Jersey Board of Public Utilities	The TOs and EDCs are generally the same entities in New Jersey. Staff is concerned that allocating costs to TOs could broaden cost socialization and shift risks away from the NLLs driving the procurement need.
Blue Ridge Power Agency, Inc.	I am concerned that TOs will not have the right authority or incentive to assign RBP costs to the appropriate entities. It is critical that data centers pay for the costs of the RBP.
Earthjustice	Allocating costs to LSEs is a better approach because it more closely mirrors cost allocation from the capacity market; utilizing that proven mechanism will likely help reduce risk.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	For Phase 2, transmission owners have no direct relationship with load or resource adequacy obligations and have no existing framework for allocating capacity costs. They are simply not the appropriate entity for this purpose.
PPL Electric Utilities Corporation d/b/a PPL Utilities	- Transmission owners (TOs)role in PJM is to move power through the PJM region. It makes no sense to consider TOs as the entity to bear the risk/costs of wholesale market supply procurement. - TOs are clearly not the correct party to be assigned RBP costs. - Any PJM costs assigned to TOs are passed, through FERC Formula Rates, on to network load so this would defeat the purpose of RBP and insulating other ratepayers from cost associated with LL capacity.
1. NRDC 2. Sustainable FERC Project	This might complicate jurisdiction over cost recovery from ratepayers, and TOs are too far from retail customers for this to lead to good decision making.
Voltus, Inc.	As discussed in answers to prior subparts of this question, assigning costs directly to large loads (or to their LSE direct representatives) effectively protects ratepayers and avoids administrative complication in passing costs through. Additionally, TOs and EDCs do not receive a clear benefit for holding the financial obligation.
Bluebird Solar LLC	We defer to PJM on the most appropriate party to be allocated costs. PJM should be prepared to address concerns that LSEs are better-placed to handle cost allocation since they transact capacity and generation with large load customers. In fact, the parties best placed for functions like defining the procurement target, handling cost allocation, and managing load shed allocations may all be different (e.g., EDCs, LSEs, and ROCs/SOCs, respectively). With this in mind, PJM will very likely need a large load registry that tracks the attributes of each large load, including things like its EDC, LSE, whether it has BYONC, and, if so, the resources associated with the load. Irrespective of whether TOs, EDCs, or LSEs are the recipients of CA, PJM should enforce credit and collateral requirements to mitigate counterparty risk.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 1 - Cost Allocation	
1. Old Dominion Electric Cooperative 2. TEC Trading, Inc.	Does not make sense
1. Virginia Electric & Power Company 2. Dominion Energy Generation Marketing, Inc 3. Dominion Energy South Carolina, Inc. 4. Eastern Shore Solar LLC 5. Greensville County Solar Project, LLC 6. Hardin Solar Energy LLC 7. Southampton Solar LLC 8. Summit Farms Solar, LLC 9. TWE Myrtle Solar Project, LLC 10. Virginia Solar 2017 Projects LLC 11. Wilkinson Solar LLC	Putting responsibilities on TOs to allocate costs would result in similar issues that will occur if EDCs are left responsible. Though TOs may have a relationship with data centers, it is ultimately up to LSEs to take on the obligation to serve data center customers.
Company Name	**Is there a different allocation of costs that should be considered?**
CPV Power Holdings, LP	The most important thing is for PJM to host a central auction to procure capacity and get new projects under construction, so that there are costs to be allocated. Sufficient time exists ahead of the delivery year for cost allocation discussions to continue beyond the Reliability Backstop Auction.
Pennsylvania Office of Consumer Advocate	Yes. The large loads that want to purchase centralized RBP capacity should be allocated the costs and no other entities. The default risk by large loads should entirely be borne by the selected suppliers in the centralized RBP.
CP Energy Marketing (US) Inc.	LSE allocation with zonal or locational adjustment where the backstop is driven by localized reliability risk, rather than system-wide socialization.
PJM Industrial Customer Coalition	Any cost allocation decision should further or effectuate the ratepayer protection pledge.
1. AES Energy Storage, LLC 2. AES ES Holdings, LLC 3. AES Integrated Energy, LLC 4. AES Laurel Mountain, LLC 5. AES Ohio Generation, LLC 6. AES Solutions Management, LLC 7. Dayton Power & Light Company (The) 8. Great Cove Solar II LLC 9. Great Cove Solar LLC 10. Miami Valley Lighting, LLC 11. sPower Energy Marketing, LLC	Either LDC, LDC as Data Center, token concept or FRR are all better ideas. FRR could be amended to allow partial FRR. Current design was punitive by those that didn't support FRR in settlement.
1. Constellation Energy Generation, LLC 2. Constellation NewEnergy, Inc. 3. Calpine Bethlehem, LLC 4. Calpine Energy Services, L.P. 5. Calpine Energy Solutions, LLC 6. Handsome Lake Energy, LLC 7. Champion Energy Marketing LLC 8. Champion Energy Services, LLC 9. Champion Energy, LLC 10. North American Power and Gas, LLC 11. Calvert Cliffs Nuclear Power Plant, LLC 12. Calpine Mid Atlantic Marketing, LLC	As per the Joint Stakeholder proposal, load that contracts with RBA eligible resources should be exempt from RBA cost allocation, while load that contracts with qualified incremental supply is responsible for RBA cost allocation at a 50% ratio
1. NRG Business Marketing LLC 2. Helix Ironwood, LLC 3. Midwest Generation, LLC 4. NRG Curtailment Solutions, Inc. 5. Direct Energy Business, LLC 6. Energy Plus Holdings LLC 7. Green Mountain Energy Company 8. Reliant Energy Northeast LLC 9. Stream Energy Pennsylvania, LLC 10. Xoom Energy, LLC	The companies offer that PJM could consider a methodology by which the EDCs identify the meters associated with the large load for which RBP supply was procured. Further, allow EDCs to identify those meters to PJM and the LSEs who serve said large load. Allow PJM to bill the LSEs for the RBP costs, noting that if load does not materialize (either due to delay or cancellation), an alternative allocation would be required. Following the meters associated with large load may also support Connect & Manage designs. This approach would require cooperative tariff revisions by both PJM and the EDCs to effectuate such methodology.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 1 - Cost Allocation	
Talen Energy Marketing, LLC	There must be a direct link between the forecasted Large Load and the cost allocation. The entity that provides the forecast must be able to determine the load (customer) that capacity is being procured for. This linkage is important because Large Loads that BYONC or have existing (grandfathered contracts) should not be allocated additional RBP costs and not be subject to Connect & Manage.
Earthjustice	Any allocation of costs should include careful mechanisms that protect ordinary ratepayers. To do so, the RBP must either ensure that all costs caused by data centers are allocated to data centers or at least provide state regulators with all necessary information to facilitate robust cost allocation.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	As discussed above, Geronimo's preferred approach is direct allocation of RBP costs to the large loads driving the procurement need. However, if it is deemed more effective and efficient to allocate to some other entities, as discussed, that should be the EDC. If costs are allocated to the EDC in the first instance, the EDC and the state should determine how to transfer those costs to the large loads and their LSEs, and manage any defaults. Loads that secure supply bilaterally in Phase 1, and are not participating in the central procurement, should not be allocated central procurement costs through any of the methods described in Questions 1–3. This creates a strong incentive for bilateral contracting and avoids double-charging proactive load.
PPL Electric Utilities Corporation d/b/a PPL Utilities	Strong preference for bilateral contracts with central procurement as a backstop only if large loads and LSEs do not contract. PJM should create a registry to link large load customers, the LSEs procuring supply on their behalf and associated costs as a transparent, simple and efficient way to set procurement targets and assign wholesale procurement costs.
1. NRDC 2. Sustainable FERC Project	LSEs and/or EUCs should be able to put in their own buy bids in the RBA and be responsible for those costs.
Voltus, Inc.	Yes – directly to the large loads through contractual arrangement. A variety of parties have raised the potential of Large Loads to directly relate to PJM as a way to greatly simplify both cost allocation and risk allocation. Voltus supports consideration of contractual relationships that allow LLs to transparently bring supply to PJM without impacting other ratepayers. LLs can have such a “minimal” relationship to PJM without becoming LSEs or PJM members.
1. Old Dominion Electric Cooperative 2. TEC Trading, Inc.	PJM contracting directly with the large load as a financial contract

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 2 - Selection Criteria	
Company Name	**Can you support selecting resources based on the average cost, $/MW-Day, over the length of the term? If "no", please explain.**
1. Constellation Energy Generation, LLC 2. Constellation NewEnergy, Inc. 3. Calpine Bethlehem, LLC 4. Calpine Energy Services, L.P. 5. Calpine Energy Solutions, LLC 6. Handsome Lake Energy, LLC 7. Champion Energy Marketing LLC 8. Champion Energy Services, LLC 9. Champion Energy, LLC 10. North American Power and Gas, LLC 11. Calvert Cliffs Nuclear Power Plant, LLC 12. Calpine Mid Atlantic Marketing, LLC	PJM needs to provide a clearer explanation of how the average cost, $/MW-Day, over the length of the term would be calculated.
New Jersey Board of Public Utilities	Staff has concerns that selecting resources based on average $/MW-Day across varying term lengths may introduce uncertainty regarding the duration and structure of resulting obligations for buyers. Staff prefers that term length parameters be established more clearly prior to the procurement to reduce uncertainty for buyers, as uncertainty regarding the contract duration could affect how market participants evaluate risk and credit exposure.
Talen Energy Marketing, LLC	The criteria must be cost plus COD.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	For Phase 2, price should be an important selection criterion, but if costs are properly allocated to the large loads, the risk of an above-market price falls primarily on the load that agreed to pay it. PJM should also have discretion to consider other factors beyond price alone, including demonstrated ability to execute and ensuring a diverse supply portfolio. We note that the more discretion PJM retains in the central procurement, the stronger the incentive for parties to reach deals in the bilateral phase on terms they control: an appropriate outcome. For Phase 1, price should be a cost that is contained between the parties to the bilateral supply arrangement (i.e., the load and the generator), and as such, the bilateral parties should be given the full discretion to determine price.
Bluebird Solar LLC	Recognizing the value of near-term UCAP, we think the RBP will work best if bids are prioritized based on COD. We also suggest that PJM require resources to bid in a single price that applies for their entire term. EDCs/LSEs/TOs should submit demand bids on behalf of their large loads that include desired MW quantity of UCAP by in service year with maximum willingness-to-pay price by start date. Thus, for example, a LL could submit two contingent bids: 200 MW of demand with a 2029 start date at $400/MW UCAP-Day, or 200 MW of demand with a 2030 start date at $300/MW UCAP-Day, with the 2030 bid being canceled if the 2029 demand was satisfied.
Company Name	**Can you support selecting resources based on prioritizing Commercial Operation Date? If "no", please explain.**
CPV Power Holdings, LP	PJM must choose COD requirements that align with resources in the queue actually capable of providing capacity to meet the shortfall. Setting COD requirements too soon will put an unreasonable limitation on the resources able to respond.
PJM Industrial Customer Coalition	If resources are selected based on a prioritization of COD, it could result in anomalous results. For example, what happens if the resource COD is delayed for reasons outside of the developer's control? Would the foregone project with a later COD be the "better" project? Could prioritizing this criterion result in unrealistically optimistic results? Also, prioritizing COD creates a risk that the new supply cannot be used to support existing load.
Zenobe Americas	• Structural bias toward existing assets and uprates. Resources already in commercial operation, or near-complete, can offer an earlier in-service date than any genuinely new build, regardless of how competitive the new-build offer is on price. Prioritizing COD over price converts the RBP from a least-cost auction into a 'first-available' auction, which advantages incumbents and undermines the policy goal of attracting new investment. Zenobe supports COD as a secondary screening criterion, i.e., a minimum in-service deadline, used as an eligibility gate, not as a price-displacing selection priority. This preserves the urgency of the procurement without distorting price-based selection.
New Jersey Board of Public Utilities	Staff thinks COD can be prioritized insofar as it aligns with the procurement target energization dates but does not support over procurement resulting from a significant mismatch between procurement timing and expected load energization. Further, Staff does not think COD should take priority over all price considerations.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 2 - Selection Criteria	
1. NRG Business Marketing LLC 2. Helix Ironwood, LLC 3. Midwest Generation, LLC 4. NRG Curtailment Solutions, Inc. 5. Direct Energy Business, LLC 6. Energy Plus Holdings LLC 7. Green Mountain Energy Company 8. Reliant Energy Northeast LLC 9. Stream Energy Pennsylvania, LLC 10. Xoom Energy, LLC	The companies are open to supporting COD as part of the selection process, but not the sole selection criteria.
Talen Energy Marketing, LLC	COD is one component of the selection criteria. Selection criteria should be a weighting of lowest cost over the term and prioritization of earlier CODs.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	For Phase 2, COD is important, but as a secondary factor. Projects with earlier CODs deliver reliability value sooner. However, COD should not be weighted so heavily that it administratively handicaps otherwise competitive projects with later online dates. If Connect and Manage rules are in place, the urgency around COD is primarily a concern for the load, where loads that need earlier supply will seek it out in the bilateral phase. The selection process should not penalize a lower-cost project simply because its COD is later, provided it falls within the eligible window. We also support extending the maximum COD to June 1, 2033, to reflect realistic development and network upgrade timelines. For Phase 1, COD should be left to the discretion of the contracting parties, perhaps with some appropriate boundaries – e.g. COD can be no later than a particular year. Connect and Manage should also drive loads to seek later-stage projects to reduce curtailment risk.
Bluebird Solar LLC	PJM should clear the RBP sequentially starting with the earliest COD that is bid in by demand. If supply resources can meet the earliest bid-in COD subject to the maximum willingness to pay by contract start date, per above, then that supply should be cleared first and its forecasted UCAP should be netted out of future DY targets.
Company Name	**Can you support selecting resources based on term length? If "no", please explain.**
PJM Industrial Customer Coalition	In answering yes, we support prioritizing resource selection based on longer term lengths on the basis that longer-term price certainty for resource development.
New Jersey Board of Public Utilities	Instead of selecting resources based on term length, Staff prefers a mechanism in which term length is set and clearly known before the auction is developed.
1. NRG Business Marketing LLC 2. Helix Ironwood, LLC 3. Midwest Generation, LLC 4. NRG Curtailment Solutions, Inc. 5. Direct Energy Business, LLC 6. Energy Plus Holdings LLC 7. Green Mountain Energy Company 8. Reliant Energy Northeast LLC 9. Stream Energy Pennsylvania, LLC 10. Xoom Energy, LLC	The companies are open to supporting term length as part of the selection process, but not the sole criteria.
Talen Energy Marketing, LLC	The term should be fixed to 15-years for every project selected, as outlined in the NEDC principles and to incent long-term investment.
Earthjustice	Prioritizing term length risks unnecessary compromises on affordability.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	GP rates this criterion medium to high. Relative to the goal of the initiative to facilitate speed to power for the relevant loads during the transition to a future ISO steady state that can effectively manage the integration of these types of loads, term is clearly relevant to facilitating effective integration of the relevant loads. However, in the Phase 2 centralized procurement, where the relevant loads will likely be far less than the initial tranche due to the Phase 1 bilateral matching, PJM may be interested in procuring generation with characteristics across a spectrum of technologies and term lengths to achieve an efficient outcome relative to system needs. As such, while still an important consideration, we believe this factor should be medium to high and should not be critical with respect to an inflexible minimum. For Phase 1, a floor minimum term length is arguably warranted given that the goal of this initiative is to accommodate these loads in a timely manner pending the ability of the grid and the ISO platforms to fully and efficiently accommodate them, which will take several years. Accordingly, for Phase 1, it is likely reasonable to set a minimum term to help facilitate the goal here. However, because Phase 1 should primarily give the bilateral parties the discretion to set the terms, perhaps shorter terms should be allowed, provided appropriate Connect and Manage rules are in place to curtail loads when shorter-term contracts expire, prior to the necessary grid build-out.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 2 - Selection Criteria	
Voltus, Inc.	Under PJM's present design, aggregations of BTM capacity will be required to show executed contracts and sites at time of bid. As explained in Voltus's presentation at the 5/5/26 CIFP-RBP meeting, this requirement is out of step with the requirement for generators to show "plans" and "MOUs" and, moreover, is out-of-step with the nature of the commercial development of distributed resources. All resources should be asked to show evidence of project feasibility, rather than full development, at time of bid. Under PJM's current design, BTM capacity aggregators will place offers with shorter contract lengths than otherwise because it is unrealistic to ask electric end-users to sign 15-year contracts beginning three years hence. A selection criteria favoring longer term-lengths will preference traditional generation, even though distributed resources are most quickly deployed, carry least stranded-asset risk, support local grid resiliency, and put revenues directly in the pockets of the electric end-users facing energy affordability challenges.
Bluebird Solar LLC	PJM should define the reliability risk period as the period where the market cannot respond to demand and ensure that all contracts cover at least through the end of this period. Then, PJM should select based on COD and price, as described above. In the event of a tie, PJM could select the project with the shortest term beyond the end of the reliability risk period. Trading off term length and price gets very complex, especially when lower priced contracts with longer terms are likely better for hedging future capacity price exposure than higher priced contracts with shorter terms.
1. Old Dominion Electric Cooperative 2. TEC Trading, Inc.	Cost needs to be the primary factor

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 3 - Collateral Requirements	
Company Name	**Can you support maintaining a static collateral requirement for the term of the contract? If "no", please explain.**
EDF Renewables	It should reduce as the resource reaches COD and as the risk of non-delivery decreases
CPV Power Holdings, LP	Maintaining a static collateral requirement for the term of the contract does not accurately reflect the supply's nonperformance risk. Unnecessarily high collateral requirements will drive costs higher, and suppliers will either be unwilling to participate in the procurement or will incorporate high collateral costs into their bids, driving capacity prices higher than necessary.
Pennsylvania Office of Consumer Advocate	Prefer reduction in collateral when the supplier is commercially operating.
Geenex Solar LLC	The collateral structure should mirror the diminishing risk profile over the RBP contract term.
American Clean Power Association	ACP cannot support a static collateral requirement. Locking in the full NPV of penalties at bid submission and holding it unchanged for the entire term front-loads the capital burden at precisely the wrong moment. Construction financing needs are most acute during the development and build period — exactly when a static requirement competes directly with credit facility capacity. As each delivery year passes and the resource demonstrates performance, the remaining risk profile declines, yet the static requirement ignores that de-risking entirely. For project-financed developers who must obtain letters of credit against finite credit facilities, this is not a theoretical concern — it flows directly into bid prices and disadvantages independent developers relative to integrated utilities with cheap balance sheet capacity. The alternative is a milestone-linked, declining collateral schedule that steps down as project risk is actually resolved — at financial close, notice to proceed, major equipment procurement, and COD — and then continues declining annually as each delivery year is successfully fulfilled. At any point, required collateral should reflect the NPV of remaining penalty exposure from that point forward, not from contract execution. This aligns financial assurance with actual remaining risk without compromising PJM's ability to ensure performance. ACP also urges PJM to replace its uniform 9.5% discount rate — derived from the Brattle CONE report and calibrated to a gas combustion turbine — with technology-specific WACCs that reflect the actual financing costs of each resource class. Storage and renewable developers carry higher WACCs, typically 11-13%, reflecting technology risk premiums and lender requirements that differ materially from a gas CT. Because the collateral formula discounts the future penalty stream to present value, applying a rate that understates a developer's actual cost of capital produces a collateral requirement disconnected from the true financial burden imposed, embedding an unnecessary cost premium in RBP bid prices.
PJM Industrial Customer Coalition	We would prefer a step-down collateral structure.
1. AES Energy Storage, LLC 2. AES ES Holdings, LLC 3. AES Integrated Energy, LLC 4. AES Laurel Mountain, LLC 5. AES Ohio Generation, LLC 6. AES Solutions Management, LLC 7. Dayton Power & Light Company (The) 8. Great Cove Solar II LLC 9. Great Cove Solar LLC 10. Miami Valley Lighting, LLC 11. sPower Energy Marketing, LLC	Collateral should decline with value amount.
Zenobe Americas	Collateral requirements during construction (pre-COD) are necessary to ensure projects manage construction risk, network-upgrade risk, equipment-delivery risk, permitting risk etc., and deliver projects. Post-COD project risks are significantly lower and once a resource has reached COD and passed interconnection commissioning, the main residual risks are from operational performance and ELCC accreditation. These are bounded risks that the shortfall-charge construct addresses. Continuing to hold the full pre-COD collateral against these much smaller residual risks ties up project equity and corporate credit unnecessarily, which projects will pass through in higher bid prices.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 3 - Collateral Requirements	
1.Aspen Generating, LLC 2. Bath County Energy, LLC 3. Seneca Generation, LLC 4. Cork Oak Solar LLC 5. Five Forks Solar, LLC 6. Fresh Air Energy XVIII, LLC 7. Fresh Air Energy XXXV, LLC 8. Hemlock Solar, LLC 9. Wyandot Solar LLC 10. Sunflower Solar LLC 11. Rockfish Solar LLC 12. North 301 Solar, LLC 13. Milford Solar LLC	Collateral should decrease upon COD at a minimum
Calibrant Energy	Once a project becomes operational, there is less risk that that project does not meet its contractual RBP commitments and this decreases each subsequent year of operation; therefore, the collateral requirements should step down once a project becomes operational. This is true for all types of supply resources.
Talen Energy Marketing, LLC	The collateral requirement should reflect the reduction in risk after COD. The initial collateral should be reduced at COD and by a pro-rata basis through the end of the contract.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	A static collateral requirement for the full contract term does not reflect the actual risk profile, which declines materially once a resource reaches COD. Collateral requirements should be calibrated to the risk they are intended to mitigate, and that risk diminishes over time. As described below, collateral structures that reflect declining risk over the contract term are more appropriate and will improve the competitiveness of the procurement by broadening participation without sacrificing risk mitigation.
1. NRDC 2. Sustainable FERC Project	Creates unnecessary carrying costs and untethers collateral from exposure.
Voltus, Inc.	A structure that returns collateral upon COD, recognizing reduced risk, would strike a better balance.
Tenaska, Inc	Security requirements should have step-downs
Bluebird Solar LLC	Consistent with industry practice, collateral requirements should drop once a project reaches COD.
Company Name	**Can you support a step-down collateral structure that mirrors the diminishing risk profile over the contract term? If "no", please explain.**
Earthjustice	Strong collateral requirements are an appropriate mechanism to protect ratepayers against the risk of supplier defaults; reducing those collateral requirements inappropriately shifts risks associated with supplier behavior to consumers instead of supply.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	We strongly support collateral structures that reflect the diminishing risk profile over the contract term. Collateral based on a 3-year multiplier pre-COD, stepping down by 50% at COD, with annual pro-rata reductions thereafter is the best approach. We would also be supportive of alternative structures that achieve the same principle of aligning collateral with actual risk exposure over time.
1. Old Dominion Electric Cooperative 2. TEC Trading, Inc.	PJM has only been managing settlement risk and FTR risk out three years. This 20 year commitment has far greater risk and PJM should establish these requirements up front
Company Name	**Can you support reducing the collateral amount to 50% upon reaching COD for the term of the contract? If "no", please explain.**
PJM Industrial Customer Coalition	A reduction by 50% seems inadequate for a 15-year term, for example.
1. AES Energy Storage, LLC 2. AES ES Holdings, LLC 3. AES Integrated Energy, LLC 4. AES Laurel Mountain, LLC 5. AES Ohio Generation, LLC 6. AES Solutions Management, LLC 7. Dayton Power & Light Company (The) 8. Great Cove Solar II LLC 9. Great Cove Solar LLC 10. Miami Valley Lighting, LLC 11. sPower Energy Marketing, LLC	Who would bear risk in a default?

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 3 - Collateral Requirements	
Zenobe Americas	If post-COD collateral is required, Zenobe supports an amortization structure (similar to what is proposed by REV/LS Power/Middle River Power) where collateral continues to step down (amortized) inequal increments over the remaining contract term. Staying at 50% throughout contract tenor is unnecessarily high.
Earthjustice	Strong collateral requirements are an appropriate mechanism to protect ratepayers against the risk of supplier defaults; reducing those collateral requirements inappropriately shifts risks associated with supplier behavior to consumers instead of supply.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	A 50% reduction at COD is a reasonable improvement, reflecting the material reduction in delivery risk once a resource is operational. We would prefer additional annual step-downs post-COD as described above, but a 50% COD reduction is a supportable minimum.
1. NRDC 2. Sustainable FERC Project	We could support this if COD is defined to mean full operation including CIRs and excludes interim deliverability.
1. Old Dominion Electric Cooperative 2. TEC Trading, Inc.	Gen collateral could possibly be reduced but load can shut down anytime and take there computers with them. So they need to stay in place

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 4 - Supply Eligibility	
Company Name	**Can you support eligibility based on needing to bring new ICAP, new MFO, and new CIRS; and no prior RPM commitment for a future delivery year at the time of the RBP? If "no", please explain.**
CPV Power Holdings, LP	All resources making an investment to increase their UCAP, including surplus, should be eligible for participation.
Geenex Solar LLC	PJM should be more expansive in regard to RBP eligibility and include CIR uprates and surplus interconnection resources.
1. AES Energy Storage, LLC 2. AES ES Holdings, LLC 3. AES Integrated Energy, LLC 4. AES Laurel Mountain, LLC 5. AES Ohio Generation, LLC 6. AES Solutions Management, LLC 7. Dayton Power & Light Company (The) 8. Great Cove Solar II LLC 9. Great Cove Solar LLC 10. Miami Valley Lighting, LLC 11. sPower Energy Marketing, LLC	Retired CIRs should be allowed to reenter market.
1. Constellation Energy Generation, LLC 2. Constellation NewEnergy, Inc. 3. Calpine Bethlehem, LLC 4. Calpine Energy Services, L.P. 5. Calpine Energy Solutions, LLC 6. Handsome Lake Energy, LLC 7. Champion Energy Marketing LLC 8. Champion Energy Services, LLC 9. Champion Energy, LLC 10. North American Power and Gas, LLC 11. Calvert Cliffs Nuclear Power Plant, LLC 12. Calpine Mid Atlantic Marketing, LLC	This definition is too narrow and ignores opportunities to bring supply that would meaningfully add capacity to the system and ensure successful procurement
New Jersey Board of Public Utilities	Staff supports recognizing incremental reliability contributions from resources and load reductions so long as they provide new UCAP. Staff is concerned that overly restrictive eligibility requirements could unnecessarily limit participation from resources capable of providing meaningful incremental reliability benefits in a short time. At the same time, Staff supports safeguards to ensure these resources are truly incremental.
1. NRG Business Marketing LLC 2. Helix Ironwood, LLC 3. Midwest Generation, LLC 4. NRG Curtailment Solutions, Inc. 5. Direct Energy Business, LLC 6. Energy Plus Holdings LLC 7. Green Mountain Energy Company 8. Reliant Energy Northeast LLC 9. Stream Energy Pennsylvania, LLC 10. Xoom Energy, LLC	The companies believe including MFO and CIRS as a predicate for eligibility eliminates DR/DER options.
Talen Energy Marketing, LLC	PJM's view of what is considered "new" is too narrow. By limiting the resources permitted to participate as long as they have not cleared in the 2027/2028 or 2028/2029 BRAs, you are able to avoid gaming of the process. In addition to PJM's definition of "new", it should also include fuel conversions for plants that would otherwise have retired and repowering previously retired plants. If the plants already did not participate in the 2027/2028 BRA in December 2025, then there is clear intent to retire and thus these MWs are incremental and "new" for purposes of resource adequacy.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	The eligibility criteria should be designed to maximize real, new MW additions to the system and mitigate the generation deficit that this initiative was created to address. Requiring new ICAP, new MFO, and new CIRS is unnecessarily restrictive and excludes resources that would deliver demonstrated, incremental UCAP through new technology investments. The eligibility standard should focus on whether the resource brings new, verifiable capacity to the system — not on a checklist of administrative prerequisites that screen out legitimate new supply.
1. NRDC 2. Sustainable FERC Project	Too restrictive, as it excludes several ways of adding real new capacity. Adding storage via SIS and improving ELCC by adding dual-fuel capability are both too important to exclude from the RBP.
Voltus, Inc.	Yes, if this standard is equally applied to DR/DER and where new ICAP for DR/DER is effectively defined to avoid broad exclusion based only on the site's past participation in a resource. For instance, a site may have participated with a nominal volume of load but then installs a new BTM asset that supports substantial new load curtailment.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 4 - Supply Eligibility	
Bluebird Solar LLC	The standard should be new ICAP and additional UCAP. Suppliers can make resource investment decisions that increase system UCAP without requiring the provision of new CIRs and MFO, e.g., battery retrofits on existing solar resources with CIRs that greatly exceed their UCAP value. In these cases, the investment in new ICAP/UCAP does not happen but for a long-term offtake agreement. If PJM desires, it could require the ICAP to be for a new resource type with an output that is complementary to the resource associated with the existing MFO and CIRs.
Company Name	**Can you support requiring supply resources needing to demonstrate new UCAP, excluding ELCC fluctuations; and no prior RPM commitment for a future delivery year at the time of the RBP to be eligible? If "no", please explain.**
EDF Renewables	I'm confused by the wording of the question regarding "excluding ELCC fluctuations" and don't know how to answer. My view is that if resources are on the hook for risk associated with ELCC fluctuations for the length of a possible 15-year contract term, they will be less likely to participate in the RBP.
1. AES Energy Storage, LLC 2. AES ES Holdings, LLC 3. AES Integrated Energy, LLC 4. AES Laurel Mountain, LLC 5. AES Ohio Generation, LLC 6. AES Solutions Management, LLC 7. Dayton Power & Light Company (The) 8. Great Cove Solar II LLC 9. Great Cove Solar LLC 10. Miami Valley Lighting, LLC 11. sPower Energy Marketing, LLC	Yes with above consideration.
1. Constellation Energy Generation, LLC 2. Constellation NewEnergy, Inc. 3. Calpine Bethlehem, LLC 4. Calpine Energy Services, L.P. 5. Calpine Energy Solutions, LLC 6. Handsome Lake Energy, LLC 7. Champion Energy Marketing LLC 8. Champion Energy Services, LLC 9. Champion Energy, LLC 10. North American Power and Gas, LLC 11. Calvert Cliffs Nuclear Power Plant, LLC 12. Calpine Mid Atlantic Marketing, LLC	This definition is too narrow and ignores opportunities to bring supply that would meaningfully add capacity to the system and ensure successful procurement
New Jersey Board of Public Utilities	Staff supports requiring supply resources demonstrate new incremental UCAP, excluding ELCC fluctuations.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	This is our preferred eligibility standard. New UCAP attributable to demonstrated technology upgrades or additions, rather than annual ELCC fluctuations, should be the test. This standard correctly includes CIR-only uprates and surplus resources where incremental UCAP comes from real physical additions. The distinction is critical: capacity added through capital investment in new equipment at an existing site is fundamentally different from paper MW appearing through accreditation methodology changes.
Voltus, Inc.	Yes. If ELCC fluctuations (against either the auction year ELCC or the auction year's prediction of the DY ELCC) are netted out, i.e. if UCAP is fixed based on the base year ELCC or the base year's prediction of the DY's ELCC, then a UCAP demonstration in future years is contractable. Voltus also supports "no prior RPM commitment for a future delivery year" if on the DR/DER side, a CSP's or DERA's additional MWs are considered net new as long as the sites providing those MWs will not be used to fill an existing RPM commitment.
Company Name	**Can you support eligibility based on both retaining the existing supply and attracting new resources in the RBP central procurement process? If "no", please explain.**
CPV Power Holdings, LP	Only truly incremental new capacity should be eligible.
Pennsylvania Office of Consumer Advocate	Supply must be new.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 4 - Supply Eligibility	
American Clean Power Association	ACP does not support expanding central procurement eligibility to include retained existing supply. ACP does not support expanding central procurement eligibility to include retained existing supply. Delayed retirements, re-licensing, and fuel switching preserve or reclassify capacity already embedded in the reliability baseline — they add nothing to closing the shortfall and including them would inflate procurement results without addressing the underlying reliability need. However, ACP urges PJM to reconsider its eligibility definition for resources that are genuinely new in the sense that matters for a capacity-only UCAP procurement. Conditioning central procurement eligibility on new CIRs — while excluding Surplus Interconnection Service resources that deliver identical net-new UCAP — is a category error. A SIS resource interconnected at a point of demonstrated deliverability contributes the same accredited capacity regardless of whether it is procured bilaterally in Phase I or through central procurement in Phase II. Excluding it from central procurement based on CIR status while permitting it as a bilateral counterparty creates a structural asymmetry with no reliability justification and removes some of the most shovel-ready supply in PJM's queue from the mechanism designed to close the most acute phase of the reliability gap. ACP recommends revising the eligibility definition to admit any resource delivering net-new UCAP not previously cleared in RPM for the committed delivery years, conditioned on a demonstrated accreditation pathway, regardless of CIR status.
CP Energy Marketing (US) Inc.	The RBP should be for new MW. Generators at risk of retirement should not be included.
PJM Industrial Customer Coalition	The RBP should only be targeting new supply; the BRA is available to support existing resources.
1. AES Energy Storage, LLC 2. AES ES Holdings, LLC 3. AES Integrated Energy, LLC 4. AES Laurel Mountain, LLC 5. AES Ohio Generation, LLC 6. AES Solutions Management, LLC 7. Dayton Power & Light Company (The) 8. Great Cove Solar II LLC 9. Great Cove Solar LLC 10. Miami Valley Lighting, LLC 11. sPower Energy Marketing, LLC	Existing units committed to RPM should not be allowed to participate
Zenobe Americas	The purpose of the RBP is to provide an investment signal and address the missing money problem for new capacity. Existing supply does not require a further price signal to stay online as the capacity market is clearing at high, albeit capped, prices. If PJM needs to address issues with supply retirements beyond the current capacity market then this should be a separate mechanism.
New Jersey Board of Public Utilities	Staff thinks we should be working to attract new resources in the RBP. While retaining existing resources is critical, Staff thinks the purpose of the RBP should be attracting new UCAP.
Calibrant Energy	Retaining existing supply should not be eligible for the RBP centralized procurement as this is not increasing the total pool of supply.
Talen Energy Marketing, LLC	There should be a recognition of executed contracts with existing supply before the RBP concept was put into play.
Earthjustice	The Statement of Principles from the National Energy Dominance Council and the Governors of PJM States specifically called for the Reliability Backstop Auction to procure new capacity resources. PJM must ensure that new demand is met with new supply to protect existing ratepayers.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	The RBP should focus exclusively on driving new supply for the large loads driving the capacity shortfall. Including existing supply retention risks, creating an incentive for existing resources to withdraw from serving existing load in order to capture above-cost payments through the RBP. This risks leaving existing customers vulnerable to a capacity deficit with no comparable focused mechanism to replace that supply. Existing resource retention is more appropriately addressed through Reliability Must Run (RMR) agreements (which are cost-based) and broader market reforms. The RBP eligibility rules should ensure that new large loads receive new supply, while existing generation continues to serve existing load under current market structures.
PPL Electric Utilities Corporation d/b/a PPL Utilities	Existing supply that may be eligible, if any, should be narrow and contribute new incremental MWs. Existing resource participation in the markets is through RPM and a broad diversion of existing resources to RBP should be discouraged.
1. NRDC 2. Sustainable FERC Project	Retaining existing supply" creates too many gaming opportunities.
Voltus, Inc.	Voltus does not support delaying the retirement of resources whose variable costs are uneconomic.
Company Name	**Please provide any additional comments.**
CPV Power Holdings, LP	PJM should prioritize resources that are advanced in the interconnection queue and have the ability to enter into construction in the near term.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 4 - Supply Eligibility	
1. Constellation Energy Generation, LLC 2. Constellation NewEnergy, Inc. 3. Calpine Bethlehem, LLC 4. Calpine Energy Services, L.P. 5. Calpine Energy Solutions, LLC 6. Handsome Lake Energy, LLC 7. Champion Energy Marketing LLC 8. Champion Energy Services, LLC 9. Champion Energy, LLC 10. North American Power and Gas, LLC 11. Calvert Cliffs Nuclear Power Plant, LLC 12. Calpine Mid Atlantic Marketing, LLC	This definition is too narrow. The RBP should provide opportunities to all resources that would meaningfully add capacity to the system and ensure successful procurement. Per the joint stakeholder proposal, RBP eligibility should include new resources (including resources using CIR transfers), all uprated MWs, uprated MWs and balance of plant (with an investment equal to or greater than $300 per kilowatt of the facility's post-uprate/expansion output), and reactivated generation (including resources that have completed the deactivation process), existing generation with an offer cap above the top of the VRR curve, any demand response committing for more than a year. Resources can be front or behind the meter.
1. Aspen Generating, LLC 2. Bath County Energy, LLC 3. Seneca Generation, LLC 4. Cork Oak Solar LLC 5. Five Forks Solar, LLC 6. Fresh Air Energy XVIII, LLC 7. Fresh Air Energy XXXV, LLC 8. Hemlock Solar, LLC 9. Wyandot Solar LLC 10. Sunflower Solar LLC 11. Rockfish Solar LLC 12. North 301 Solar, LLC 13. Milford Solar LLC	Preference to support new ICAP, MFO, CIRs and new UCAP, excluding ELCC fluctuations; and no prior RPM commitment for a future delivery year at the time of the RBP to be eligible
Calibrant Energy	Calibrant is strongly supportive of the inclusion of new Demand Response as an eligible technology in the centralized procurement. In addition to locations that have never participated in PJM's RPM, PJM should also include DR/DER "uprates" and "reactivations" at locations that have previously participated in PJM's RPM as eligible new resources in the Reliability Backstop Procurement. Like an existing generator, an existing location already participating in DR may see an opportunity to expand their DR offering in response to this procurement. For example, a 50 MW location that is enrolled for 25 MW of DR today, may seek to make additional investment in response to this procurement to provide an additional 25 MW of DR. This additional 25 MW of DR should be eligible for the RBP. Similarly, a location that has previously participated as DR in the RPM, but is not part of an aggregation that has a RPM commitment for current or future delivery years, may be willing to reenter the PJM market if it can secure a long term commitment through the reliability backstop procurement. This is new supply and should be eligible to participate in the RBP, similar to reactivations for generating resources.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	Geronimo Power has a number of projects in PJM that qualify as surplus resources under PJM's current definitions. These involve the addition of new technology at existing or planned sites, creating incremental UCAP attributable to real capital investment — not ELCC methodology changes. Excluding these resources narrows the supply pool, reduces competition, and risks higher procurement costs for the large loads bearing those costs. We urge PJM to adopt an eligibility framework that includes surplus resources and CIR-only uprates, where the new UCAP is due to demonstrated technology upgrades or additions, appropriately distinguishing between genuine new supply and paper MW from accreditation changes. Unlike other considerations and criteria, the eligibility criteria for Phase 1 and Phase 2 should be aligned based on the same guiding principles and goals. Accordingly, Geronimo's comments on this specific issue for Phase 2 apply equally to Phase 1.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 5 - ELCC Risk	
Company Name	**Can you support a package that the RBP seller (supply) determines the UCAP value over the term of the contract, and is potentially exposed to shortfall charges if unable to meet the UCAP obligation at the time of applicable Delivery Year; ineligible to replace RBP MW? If "no", please explain.**
EDF Renewables	We will not participate in the procurement if we are exposed to these charges that we have no control over. Our performance can remain constant, or even improve over the contract term, but PJM's ELCC calculation can devalue the resource and expose us to deficiency charges and potential penalties.
CPV Power Holdings, LP	A project should be at risk of shortfall charges for not meeting its obligations, but it should have the opportunity to replace its MW.
Geenex Solar LLC	RBP sellers and PJM generation resources should not have to face penalties due to forces outside of their control, especially changes in ELCC Class Ratings on a year-by-year basis.
American Clean Power Association	ACP cannot support ineligibility for replacement MW as a blanket rule. The treatment should depend on the source of the deficiency. For non-ELCC related UCAP deficiencies — forced outages, equipment failures, operational shortfalls within the supplier's control — the seller should retain the opportunity to remedy through replacement MW. Removing that option entirely is disproportionate and inconsistent with the risk management tools available to all other RPM-committed resources. Performance accountability does not require eliminating every remedial pathway. For ELCC-driven UCAP deficiencies the framework should be different. As discussed below, ELCC changes reflect PJM methodology decisions outside any individual party's control. Where a UCAP shortfall is caused by a decline in the ELCC class average, both the supplier and the contracted load share exposure to that outcome — the supplier faces a delivery gap and the load faces a degraded BYONC showing. ACP recommends that both parties bear a corresponding obligation to remedy: the supplier through replacement MW sourced from ELCC-eligible resources, and the load through supplemental procurement to restore its BYONC coverage to the contracted level. A de minimis threshold of 5% would filter routine class average volatility from triggering this obligation, reserving the shared remedy requirement for material methodology-driven shifts that genuinely impair the reliability value of the RBP commitment.
CP Energy Marketing (US) Inc.	This places asymmetric and largely uncontrollable ELCC risk on sellers, materially increasing costs or deterring participation.
1. AES Energy Storage, LLC 2. AES ES Holdings, LLC 3. AES Integrated Energy, LLC 4. AES Laurel Mountain, LLC 5. AES Ohio Generation, LLC 6. AES Solutions Management, LLC 7. Dayton Power & Light Company (The) 8. Great Cove Solar II LLC 9. Great Cove Solar LLC 10. Miami Valley Lighting, LLC 11. sPower Energy Marketing, LLC	It places full ELCC risks on developers.
Zenobe Americas	Zenobe strongly opposes this package as it is functionally unworkable and not bankable for BESS projects or any resource with significant ELCC accreditation exposure. In addition, making it ineligible to replace RBP MW means that the project has no cure. ELCC erosion is outside the seller's control and the class rating for 4-hour storage is a function of system-wide storage penetration and PJM's annual recalibration of class ratings. Individual resources cannot influence the class rating. Exposing BESS to potential shortfall charges is asking a resource to face cash penalties that is has no control over. The expected value of those penalties (plus contingency for caution) will be passed through into significantly higher bid price premiums, and even then will be hard to raise debt financing against.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 5 - ELCC Risk	
1. Constellation Energy Generation, LLC 2. Constellation NewEnergy, Inc. 3. Calpine Bethlehem, LLC 4. Calpine Energy Services, L.P. 5. Calpine Energy Solutions, LLC 6. Handsome Lake Energy, LLC 7. Champion Energy Marketing LLC 8. Champion Energy Services, LLC 9. Champion Energy, LLC 10. North American Power and Gas, LLC 11. Calvert Cliffs Nuclear Power Plant, LLC 12. Calpine Mid Atlantic Marketing, LLC	The non performance/shortfall penalty structure and replacement rules should mirror the existing capacity performance and RPM market rules.
1. Aspen Generating, LLC 2. Bath County Energy, LLC 3. Seneca Generation, LLC 4. Cork Oak Solar LLC 5. Five Forks Solar, LLC 6. Fresh Air Energy XVIII, LLC 7. Fresh Air Energy XXXV, LLC 8. Hemlock Solar, LLC 9. Wyandot Solar LLC 10. Sunflower Solar LLC 11. Rockfish Solar LLC 12. North 301 Solar, LLC 13. Milford Solar LLC	Suppliers do not have the ability to control ELCC changes, and therefore would have to include this unmanageable risk into offers, which creates a risk of high RBP offers.
New Jersey Board of Public Utilities	Staff has concerns with the RBP seller determining its own UCAP value in the central procurement, particularly if the penalties are not high enough to incentivize a reasonable determination of UCAP values. Staff prefers a structure that does not impose risks on the existing customers.
Calibrant Energy	Without an ability to manage ELCC risk in any way under a RBP contract, sellers are going to be unable to finance projects. Sellers cannot take actions at their facilities to protect themselves from declining class-level ELCC values. To the extent that the RBP is intended to be a mechanism to help finance projects in the near-term to meet the near-term load growth, we believe it is appropriate that RBP contracts help sellers manage ELCC uncertainty.
Talen Energy Marketing, LLC	RBP replacement capacity should be permitted if the need for replacement is limited to a reduction in UCAP while the ICAP of facility remains constant (no speculative projects but allows for replacing MWs due to ELCC changes).
Earthjustice	This approach unreasonably penalizes resources for changes that are beyond their control. This approach risks deterring participation from new supply that can come online quickly and provide affordable energy, because a supplier that performs perfectly as designed could nonetheless face shortfall charges.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	This option places the full burden of ELCC risk on the seller with no mitigation. The basic principle of risk management is that risk should be borne by the party best positioned to manage it. Suppliers cannot control or manage PJM's ELCC methodology, where PJM reserves the right to change accreditation values annually based on system conditions, load forecasts, and resource mix changes. Requiring sellers to bear this risk with no replacement eligibility means they must price that uncertainty into their bids, increasing procurement costs, which, in Phase 2, should be a concern. Combined with shortfall charges, this creates a risk profile that is extremely difficult to finance over a 10–15-year contract horizon.
1. NRDC 2. Sustainable FERC Project	Replacement must be an option. We appreciate concerns worry about gaming it, but replacement transactions are a vital tool for legitimate risk management.
Voltus, Inc.	Voltus can support supplier allocation of ELCC risk over the course of the RBP obligation if replacement capacity mechanisms are offered, as per the option in the next question. Otherwise, the risk is unhedgeable and will have the concrete impact of reducing offers volumetrically, contrary to the goals of RBP.
Tenaska, Inc	Uncontrollable risk

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 5 - ELCC Risk	
Bluebird Solar LLC	We could support a proposal where any deficiencies due to class ELCC changes are "penalized" at 100% of the contract price, i.e., a simple revenue clawback where we are only paid for the UCAP we provide. In this case, PJM will need to value resources based on price, and will need to take a view on what the quantity of a resource is worth. As explained in past proposals, our preference would be to offer two options: 1) pay-as-delivered or 2) fixed-for-floating based on the class ELCC forecast with supply retaining resource performance adjustment risk.
1. Virginia Electric & Power Company 2. Dominion Energy Generation Marketing, Inc 3. Dominion Energy South Carolina, Inc. 4. Eastern Shore Solar LLC 5. Greensville County Solar Project, LLC 6. Hardin Solar Energy LLC 7. Southampton Solar LLC 8. Summit Farms Solar, LLC 9. TWE Myrtle Solar Project, LLC 10. Virginia Solar 2017 Projects LLC 11. Wilkinson Solar LLC	As PJM is procuring new ICAP, the RBP seller should determine an ICAP value to offer; the accredited UCAP would be determined by forecasted accreditation values determined by PJM—risk from ELCC deviations should be borne by the seller, as is done today. Additionally, supply should have a way to remedy a UCAP shortfall due to ELCC changes.
Company Name	**Can you support a package that the RBP seller (supply) determines the UCAP value over the term of the contract, and is potentially exposed to shortfall charges if unable to meet the UCAP obligation at the time of applicable Delivery Year; eligible to replace RBP MW with eligible MW? If "no", please explain.**
EDF Renewables	This is overly complicated and still exposes resources to more risk than they are willing to accept
Geenex Solar LLC	See the answer to the question above, and RBP sellers should also not have to pay to replace RBP UCAP MW due to year-to-year fluctuations in ELCC Class Ratings.
American Clean Power Association	ACP can conditionally support this package. Allowing suppliers to self-determine their UCAP value gives developers the flexibility to bid conservatively against ELCC uncertainty — pricing in a downside accreditation scenario rather than being locked into a fixed obligation they cannot control. Restoring replacement MW eligibility is the critical improvement over PJM's original design; it gives suppliers a practical hedge against ELCC-driven shortfalls, allowing them to substitute eligible capacity rather than face naked daily penalty exposure with no remedy available. The residual concern is bid pricing distortion. A supplier self-determining UCAP under shortfall charge exposure will rationally price in a downside ELCC scenario, inflating bid prices and increasing costs to load — not because the resource is more expensive to build, but because the supplier is bearing a system-level methodology risk it cannot efficiently hedge. The de minimis threshold ACP recommended in prior comments would address this directly: ELCC class average changes within 5% of contracted accreditation are absorbed by the system with no shortfall charge and no obligation adjustment, removing the conservatism premium for routine volatility while preserving full supplier accountability for genuine performance shortfalls. Changes exceeding 5% trigger the standard shortfall and replacement MW framework. With that refinement, ACP can support this package. The supplier's Installed Capacity obligation remains unchanged throughout — this proposal addresses only ELCC-derived UCAP changes.
CP Energy Marketing (US) Inc.	Shortfall exposure tied to ELCC volatility still over-allocates risk to supply.
Zenobe Americas	This is better than the previous package as making it eligible to replace RBP MW with eligible MW introduces a cure to ELCC deficiency. However, replacing RBP MW with eligible MW is not straightforward due to the following reasons: potential land availability or permitting risks for expansion, finding offtake for additional MW for the non-capacity revenue in an uncertain future market, future BESS capex prices. These reasons means that a significant ELCC risk premium will still be prices into BESS bids.
New Jersey Board of Public Utilities	Staff recognizes the importance of attracting supply participation in the RBP. Staff supports the eligibility of supply to replace RBP MW insofar as the replacement MWs are new UCAP.
Calibrant Energy	The ability to replace RBP MW with eligible new MWs, through the procurement of additional MWs from other new supply resources or by taking actions at an RBP supply resource (e.g. adding storage capability to increase duration), is an important mechanism to manage seller risk; however, it does not go far enough to help sellers manage this risk because the availability/cost of new supply will be difficult to forecast and price into an RBP contract.
Talen Energy Marketing, LLC	RBP replacement capacity needs to be permitted if the need for replacement is limited to a reduction in UCAP while the ICAP of facility remains constant (no speculative projects but allows for replacing MWs due to ELCC changes.
Earthjustice	This option still risks deterring participation from affordable resources that are quick to deploy, because it makes the generator bear the risk of changes beyond its control.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 5 - ELCC Risk	
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	While replacement MW eligibility is an improvement, retaining shortfall charges for ELCC-driven UCAP reductions still penalizes suppliers for factors entirely outside their control. This is inconsistent with PJM's own 2025 RPM reforms removing deficiency penalties for ELCC-related shortages. If PJM retains the right to change ELCC values annually, suppliers should not face shortfall charges when their physical ICAP has not changed.
Tenaska, Inc	UCAP has associated ELCC risk
Bluebird Solar LLC	Allowing replacement runs the risk of subbing in MWs that didn't need RBP to come to market, particularly in the out years. As previously presented, the only conditions under which we think replacement MWs make sense is if a project that receives an award fails to achieve COD and its replacement is coming online in a year when the capacity market collar is in effect, which we think is an appropriate condition for proving additionality.
Company Name	**Can you support a package that the RBP seller (supply) UCAP MW are equal to the ELCC Class Average value over the term of the contract, without being exposed to shortfall charges due to ELCC fluctuations; eligible to replace RBP MW with eligible MW? If "no", please explain.**
Pennsylvania Office of Consumer Advocate	Prefer suppliers bear the UCAP risk, otherwise UCAP risk could be transferred to non-large loads.
American Clean Power Association	ACP conditionally supports this package. Using the ELCC Class Average as the commitment basis is consistent with how PJM already accredits these resources in RPM today — solar resources receive the solar class average, wind the wind class average — so this represents continuity with the existing accreditation framework rather than a new protection. Restoring replacement MW eligibility is a meaningful improvement over PJM's original design and gives suppliers a standard risk management tool to address delivery gaps without disproportionate penalties. However, the ELCC Class Average itself is not static. PJM's class-level ELCC values have shifted materially in recent years — the solar class average has declined as the fleet has grown and marginal stress hours have shifted — and further changes are anticipated as renewable penetration increases. A supplier committing to deliver 100 MW of UCAP over 15 years under a fixed class average obligation remains exposed to class-level methodology shifts outside its control. A decline from 100 MW to 97 MW still leaves the supplier's obligation stranded, the contracted load's BYONC showing exposed on the uncovered 3 MW, and no mechanism to cure C&M curtailment through financial settlement alone. ACP recommends supplementing this package with a de minimis threshold applied to class average changes. Movements within 5% of contracted accreditation are absorbed by the system with no adjustment to any party's obligation — filtering routine class-level volatility without churning EDC allocations and load BYONC showings. Changes exceeding 5% trigger a full reset to actual class accreditation, with the supplier's obligation and the load's BYONC showing adjusting automatically and the system absorbing the gap through a marginally more inelastic BRA supply curve. This applies solely to ELCC-derived UCAP changes — the supplier's Installed Capacity obligation remains unchanged throughout.
PJM Industrial Customer Coalition	We could support this approach only if a unit-specific ELCC were used.
1.Aspen Generating, LLC 2. Bath County Energy, LLC 3. Seneca Generation, LLC 4. Cork Oak Solar LLC 5. Five Forks Solar, LLC 6. Fresh Air Energy XVIII, LLC 7. Fresh Air Energy XXXV, LLC 8. Hemlock Solar, LLC 9. Wyandot Solar LLC 10. Sunflower Solar LLC 11. Rockfish Solar LLC 12. North 301 Solar, LLC 13. Milford Solar LLC	This option is a minimum requirement, though still maintains a high level of unmanageable risk to the seller
New Jersey Board of Public Utilities	Staff understands the risks involved and acknowledges that the ELCC risk must be borne somewhere. Staff prefers a structure that does not impose risks on the existing customers. If PJM proceeds with this package, Staff encourages PJM to mitigate any downstream impacts on how the capacity contributed by RBP supply is accounted for in the BRA.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 5 - ELCC Risk	
1. NRG Business Marketing LLC 2. Helix Ironwood, LLC 3. Midwest Generation, LLC 4. NRG Curtailment Solutions, Inc. 5. Direct Energy Business, LLC 6. Energy Plus Holdings LLC 7. Green Mountain Energy Company 8. Reliant Energy Northeast LLC 9. Stream Energy Pennsylvania, LLC 10. Xoom Energy, LLC	The companies are open to solutions that reduce ELCC risk, but not when they apply exclusively to the RBP resources.
Earthjustice	Average ELCC changes over time and presents significant risk for generators that perform 100% as designed. A fixed ELCC value is a better approach.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	Using the ELCC Class Average provides a reasonable benchmark while insulating sellers from shortfall charges for class-wide accreditation changes. Paired with replacement MW eligibility, this appropriately balances risk. However, we have a slight preference for Option 4 as described below.
1. NRDC 2. Sustainable FERC Project	Forecasting class average ELCC over a long term contract seems very uncertain. Can't form an opinion on this without knowing how the initial reliability surplus and later reliability gap will be handled.
1. Bluebird Solar LLC	We could support a resource's ELCC in each DY that is set at the forecast ELCC Class Average value for the corresponding year according to a PJM forecast that is set at the time of offering into the auction, and would also factor in a resource's ELCC performance adjustment (RPA) to its UCAP. Shortfalls due to an RPA<1 should be penalized at 100% of the contract price (i.e., revenue clawback), surplus due to an RPA>1 should be allowed to keep their surplus RPM revenues. This model is Option 2 described in our comments above.
1. Virginia Electric & Power Company 2. Dominion Energy Generation Marketing, Inc 3. Dominion Energy South Carolina, Inc. 4. Eastern Shore Solar LLC 5. Greensville County Solar Project, LLC 6. Hardin Solar Energy LLC 7. Southampton Solar LLC 8. Summit Farms Solar, LLC 9. TWE Myrtle Solar Project, LLC 10. Virginia Solar 2017 Projects LLC 11. Wilkinson Solar LLC	PJM needs to demonstrate that this would not impact the calculations of the reliability requirement.
Company Name	**Can you support a package that the RBP seller (supply) UCAP MW are one fixed value based on the current preliminary ELCC values over the term of the contract, without being exposed to shortfall charges due to ELCC fluctuations; eligible to replace RBP MW with eligible MW? If "no", please explain.**
Pennsylvania Office of Consumer Advocate	Prefer suppliers bear the UCAP risk, otherwise UCAP risk could be transferred to non-large loads.
New Jersey Board of Public Utilities	As in the previous response, Staff prefers a structure that does not impose risks on the existing customers. If PJM proceeds with this package, Staff encourages PJM to mitigate any downstream impacts on how the capacity contributed by RBP supply is accounted for in the BRA.
1. NRG Business Marketing LLC 2. Helix Ironwood, LLC 3. Midwest Generation, LLC 4. NRG Curtailment Solutions, Inc. 5. Direct Energy Business, LLC 6. Energy Plus Holdings LLC 7. Green Mountain Energy Company 8. Reliant Energy Northeast LLC 9. Stream Energy Pennsylvania, LLC 10. Xoom Energy, LLC	The companies are open to solutions that reduce ELCC risk, but not when they apply exclusively to the RBP resources.
Calibrant Energy	It is important to reflect expectations of the annual UCAP value in the RBP contracts based on the expectation of UCAP at the time of the contract. This is consistent with PJM's proposal related to Connect and Manage which evaluates BYONC based on the year 1 UCAP of a resource.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 5 - ELCC Risk	
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	This is Geronimo's preferred option. PJM should publish an official long-term ELCC forecast prior to the procurement, and UCAP commitments should be benchmarked to that forecast for the contract term. If UCAP decreases due to ELCC changes while ICAP remains unchanged, the resource should be paid on its original contract amount, be eligible for replacement MW, and not face shortfall charges. Importantly, this is not a one-sided ask: if ELCC values increase above the forecast, the resource would not capture that upside, and the benefits would flow to the system. Fixing the ELCC value at contract execution is a symmetric approach that provides revenue certainty to suppliers while protecting buyers from overpaying if accreditation values improve. This mirrors the 2025 RPM precedent and reflects the basic principle that risk should be borne by the party best positioned to manage it, and suppliers cannot manage PJM's methodological decisions.
1. NRDC 2. Sustainable FERC Project	Can't form an opinion on this without knowing how the reliability gap from decreasing ELCC will be made up.
Bluebird Solar LLC	This is functionally the same as taking a fixed ELCC profile.
1. Virginia Electric & Power Company 2. Dominion Energy Generation Marketing, Inc 3. Dominion Energy South Carolina, Inc. 4. Eastern Shore Solar LLC 5. Greensville County Solar Project, LLC 6. Hardin Solar Energy LLC 7. Southampton Solar LLC 8. Summit Farms Solar, LLC 9. TWE Myrtle Solar Project, LLC 10. Virginia Solar 2017 Projects LLC 11. Wilkinson Solar LLC	No, sellers should be exposed to shortfall charges. PJM also needs to demonstrate that this would not impact the calculations of the reliability requirement.
Company Name	**Please provide any additional comments.**
CP Energy Marketing (US) Inc.	Capital Power supports an RBP design that allocates costs to Load Serving Entities consistent with cost causation and existing capacity market frameworks. LSE-based allocation appropriately aligns responsibility for meeting load with the entities best positioned to manage resource adequacy and procurement decisions. More broadly, the RBP should remain focused on attracting incremental capacity through clear eligibility rules and transparent, least-cost selection to address reliability needs efficiently.
Zenobe Americas	Zenobe supports package 3 & 4 as both being workable and bankable for BESS projects. Our preference would be for package 3 as it best aligns risks to what the project can control (resource performance vs class average)
1. Constellation Energy Generation, LLC 2. Constellation NewEnergy, Inc. 3. Calpine Bethlehem, LLC 4. Calpine Energy Services, L.P. 5. Calpine Energy Solutions, LLC 6. Handsome Lake Energy, LLC 7. Champion Energy Marketing LLC 8. Champion Energy Services, LLC 9. Champion Energy, LLC 10. North American Power and Gas, LLC 11. Calvert Cliffs Nuclear Power Plant, LLC 12. Calpine Mid Atlantic Marketing, LLC	PJM should include a mechanism that recognizes the interplay between the RBP and RPM markets and ensures long-term resource adequacy. Several stakeholders, including the Joint Stakeholders and Shell, have provided mechanisms to address this issue. Failure to include such a mechanism undermines resource adequacy by sending a signal that new resources should rely on future backstop procurements rather than competitive market signals for development and commencing commercial operation. It also may result in existing supply retiring of leaving the PJM market, further exacerbating resource adequacy issues.
1. Aspen Generating, LLC 2. Bath County Energy, LLC 3. Seneca Generation, LLC 4. Cork Oak Solar LLC 5. Five Forks Solar, LLC 6. Fresh Air Energy XVIII, LLC 7. Fresh Air Energy XXXV, LLC 8. Hemlock Solar, LLC 9. Wyandot Solar LLC 10. Sunflower Solar LLC 11. Rockfish Solar LLC 12. North 301 Solar, LLC 13. Milford Solar LLC	If there is a UCAP decrease due to ELCC change compared to the PJM long-term ELCC forecast, but ICAP is the same as committed, then the resource should be paid based on its original UCAP contract amount, should be allowed to procure replacement MW, and is not subject to the 20% shortfall charge for the ELCC-related UCAP MW difference.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Question 5 - ELCC Risk	
1. NRG Business Marketing LLC 2. Helix Ironwood, LLC 3. Midwest Generation, LLC 4. NRG Curtailment Solutions, Inc. 5. Direct Energy Business, LLC 6. Energy Plus Holdings LLC 7. Green Mountain Energy Company 8. Reliant Energy Northeast LLC 9. Stream Energy Pennsylvania, LLC 10. Xoom Energy, LLC	It is reasonable to expect ELCC risk to be reflected in offers, whether in volume or price. Efforts to reduce such risk are welcome, but cannot be done without consideration of impacts on the remainder of the supply resources. PJM may wish to consider additional ELCC classes to better reflect differentiated asset types.
Talen Energy Marketing, LLC	In addition to the survey above, Talen would like to provide additional holistic comments. PJM's proposal is also glaringly lacking in locational goals (e.g., PJM should issue locational-based targets for the procurement, within a range for each area) and some sort of 90-day interconnection study for the "top portion" of likely-to-be-selected projects. In addition, PJM's proposal should not have a COD cut-off, due to the risk that not enough resources are procured. Finally, the RBP portion of this process needs to run sooner, and for the bilateral contracting period to overlap with the procurement period such that when large load customers contract during this process those amounts are removed from the total procurement goals.
1. Green River Holdings, LLC 2. Geronimo Power Marketing, LLC	ELCC risk allocation is the single most important design element for financing of long-term contracts under the RBP. ELCC values are subject to significant volatility driven by changes in the resource mix, load shapes, and PJM's accreditation methodology – none of which individual suppliers can control. Placing uncapped ELCC risk on sellers will require them to price that uncertainty into their bids, increasing procurement costs for the large loads bearing those costs. We note that the 2025 RPM reforms already recognized this principle. RBP should be at least as protective given the longer contract terms involved. A fixed ELCC forecast benchmark provides a symmetric risk allocation: suppliers give up ELCC upside in exchange for protection from downside, giving both parties a transparent and auditable basis for long-term commitments.
Voltus, Inc.	ELCC fluctuations are one factor impacting obligations or capacity needs over the course of the contract term; another is that the LL doesn't ramp as quickly as expected. In the current PJM proposal, EDCs can trade their obligations. Whichever entity is allocated the cost of RBP (TO, EDC, LSE, LL), Voltus supports true-up mechanisms to manage shifting obligations over extended contracts.

Stakeholder Feedback on Reliability Backstop Procurement Survey Responses

Company Name	Please provide any feedback on the PJM initial proposal presented on April 16, 2026 or any stakeholder proposals presented at the CIFP – Reliability Backstop Procurement meetings on May 4 and May 5, 2026.
1. Alpha Generation, LLC 2. Parkway Generation Operating LLC	Cost Allocation - Allocating costs to the EDCs will encourage more accurate load forecasting by EDCs. EDCs have direct contact with the retail customers during the interconnection process, providing them with the best insight as to the likelihood of load interconnecting. Plus, in competitive states, LSEs have little visibility into the forecasting sausage making process, forcing them to take on the risk of over- and under-forecasting. Selection criteria for both the RBA and Connect and Manage - the selection criteria should include 1) cost, 2) financial viability of the entity, 3) speed to market, 4) expected accreditation values, 5) certainty of interconnection costs, and 6) term length Collateral - Both suppliers and load need to post collateral with a reduction of collateral on the supply side over time as the resources complete milestones and become COD Eligibility - Eligibility for both the RBA and Connect and Manage should be new, incremental MW only. AlphaGen strongly opposes the participation of any existing resources on either the RBA or Connect and Manage. However, If the stakeholders decide that certain existing resources are eligible because they are at risk of retirement, the economic viability of the existing resource must undergo the full economic review by the IMM (per current protocol.). ELCC Risk - ELCC risk should be borne by the supplier. Suppliers have the ability to price and manage the risk. In order for the supplier to manage the risk, the supplier needs 1) have the discretion to offer in below its full ELCC value into the RBA for the resource; and/or 2) be able to cover its shortfall with both new and existing resources in the delivery year of the shortfall. AlphaGen, in general and with some modifications, supports PJM's RBA and Connect and Manage approaches.