Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM

THE **Brattle** GROUP

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Summary

The implementation of the PJM capacity market as an annual design made sense in the historical context with summer having both the highest demand and shortest supply. However, significant changes to the resource mix and the nature of reliability concerns in both seasons have introduced a more prominent need to establish resource adequacy in both the summer and winter seasons. To address winter supply adequacy and enable summer resources, PJM has introduced a series of reforms, from the prior summer-only demand response program, to Capacity Performance, to a new resource matching program for some seasonal resources.

Despite these reforms, the current PJM capacity market design maintains several shortcomings that limit the full participation of seasonal capacity resources to more cost-effectively meet seasonal reliability needs. Because it maintains an annual design, PJM effectively imposes the same reliability requirement in both the summer and winter seasons even though winter peak load is substantially lower and could be met reliably with 13,538 to 16,172 UCAP MW less capacity.[1] Ignoring that reality means that summer-only capacity cannot participate without being matched with an equivalent amount of winter-only capacity. This results in inefficiently little reliance on summer-only resources, and inefficiently high procurement of annual capacity. The effects are exacerbated by limitations of the seasonal resource matching program.

We estimate that approximately 10,000 MW of winter-only supply remains non-committed in the capacity market, primarily from higher winter ratings of combustion turbines and other thermal resources that are categorically excluded from seasonal matching. In the summer season, we estimate that 1,700 to 6,000 MW of summer-only supply is not offering or not clearing in the auction due to the matching requirement, the limited nature of the seasonal matching program, and under-remuneration of summer capacity that does clear. Prices awarded to seasonally-matched resources are based on a simple 50/50 split of the annual resource price, rather than differentiating payments based on the incremental cost and value of supply between seasons.

These challenges can be addressed by applying standard economic principles of supply and demand. The most important elements of any effective design solution should include:

- **Separate Summer and Winter Reliability Requirements** that measure the true reliability need in each season. To maximize efficiency, the reliability risk borne in each season should be adjusted to equalize the marginal cost of avoiding load shed events. Under current and near-term market conditions with excess of winter supply, this suggests that the large majority of reliability risk should continue to be borne in the summer season.

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[1] See PJM, Winter Season Resource Adequacy Analysis, February 2, 2018. The range corresponds to the requirements under Scenario 5A, as discussed in the main text.

- **Separate Summer and Winter Capacity Ratings for All Resources** to maximize the ability of every resource type to contribute to one or both seasons' capacity needs. This would better incentivize performance in both seasons and more fully enable a wider variety of seasonal resources: summer-only demand response, energy efficiency, and solar photovoltaics; winter-focused wind and thermal generation; and other resources including seasonal imports/exports, and mid-year entry/exit.

- **Differentiated Summer and Winter Capacity Payments** that are reflective of the marginal cost of supply and incremental reliability value of capacity in each season. Such pricing will appropriately signal the market to attract and retain the most valuable resources in the system and most cost-effectively meet reliability objectives.

PJM's prior approach to accommodating summer-only demand response subject to constraints incorporated some, but not all, of these key design elements. The prior approach implicitly (though not explicitly) imposed separate summer and winter requirements by allowing some summer resources to clear without a winter match. However, the mechanism did not account for the variations in resources' seasonal capacity ratings, did not enable participation of seasonal resources other than summer demand response, and was not designed to produce prices consistent with marginal reliability value across the two seasons.

One solution that would incorporate all of these key design elements would be a comprehensive two-season capacity market with co-optimized auction clearing. A two-season market would establish separate reliability requirements and capacity demand curves for summer and winter needs. Demand curve quantity and price parameters would consider peak load and marginal cost of meeting supply in each season (to help produce efficient prices reflecting the same value per unit of avoided load shed event between seasons). On the supply side, every resource would be awarded separate summer and winter capacity ratings, with the option to offer separate prices for summer-only, winter-only, or annual supply. Auction clearing would be conducted on a co-optimized basis to maximize total surplus across the two seasons. Resources offering and clearing on an annual basis would be guaranteed to earn annual revenues at least as high as their annual offer price (although revenues might be concentrated in one of the two seasons).

This two-season capacity market design would have several advantages. It would enable seasonal capacity of all resource types and more accurately address seasonal capacity supply and demand in every location. By significantly reducing winter procurements and enabling lower-cost resources, we estimate that such a design could achieve long-run societal benefits of roughly $100-600 million per year on an enduring basis. Short-run *customer benefits* could be substantially higher if clearing prices decreased temporarily with the introduction of more efficient seasonal construct and the inclusion of many more low-cost resources.

Over the long term, an efficient seasonal construct is likely to become increasingly important as the resource mix continues to shift toward non-traditional resources with differentiated seasonal capability such as wind, solar, distributed resources, and imports, and as load patterns change with the potential electrification of transportation and heating.

I. The Current Annual Capacity Market Design Has Several Shortcomings

The current PJM capacity market is designed primarily to meet summer resource adequacy needs, consistent with the historically tighter supply-demand conditions in the summer season. Over the past decade, the supply mix has shifted toward a different composition of resources with more variation in seasonal availability. In response, PJM has introduced several reforms aimed at addressing specific concerns with winter reliability or seasonal resource participation, but has not yet addressed other challenges. The most significant shortcomings related to efficiently meeting seasonal capacity needs are: (a) that winter capacity procurements far exceed the quantity needed to maintain reliability; (b) that many seasonal resources are undervalued or excluded from selling capacity into the PJM capacity market; and (c) payments awarded to seasonally-matched resources are not reflective of the difference in marginal cost or marginal value across the two seasons. We discuss each of the shortcomings as follows.

A. WINTER CAPACITY PROCUREMENTS FAR EXCEED THE RELIABILITY NEED

PJM's current capacity market is designed as if winter capacity needs were as high as summer capacity needs, which they are not. PJM establishes an annual reliability requirement based on a reserve margin above summer peak load, and requires that same quantity of capacity to be available throughout the year. As a consequence, PJM procures the same quantity of capacity for winter as for summer, far exceeding the winter reliability need. As illustrated in Figure 1, the annual reliability requirement is 16.6% above the summer peak load in installed capacity (ICAP) terms. This translates to a 34.9% reserve margin above winter peak load.[2]

The 34.9% winter reserve margin imposed implicitly by the annual capacity construct significantly exceeds the reserve margin needed to maintain reliability. PJM explains that such high reserve margins are consistent with a traditional approach to reliability that sought to meet the more challenging summer peak with just enough capacity to meet the annual reliability target while maintaining essentially zero probability of supply shortages in winter.[3] However, recent analyses conducted by PJM staff indicate that the PJM region could reduce winter capacity procurements by 13,538 to 16,172 UCAP MW without compromising the reliability overall if PJM adopted different LOLE distributions between summer and winter.[4]

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[2]   See PJM, Winter Season Resource Adequacy Analysis Status Report, October 26, 2017, slide 5.

[3]   See PJM, FERC Docket No. EL17-32-000, Answer of PJM Interconnection, L.L.C., January 23, 2017.

[4]   See PJM, Winter Resource Adequacy, February 2, 2018. We refer to Scenario "5A" for two reasons: (1) it excludes the 2014 Polar Vortex from outage rates, reflecting improved PJM and market participant operating procedures, and the improved quality of UCAP MW achieved through the Capacity Performance mechanism; and (2) that scenario assumes no scheduled maintenance during winter peaks, a reasonable assumption if winter reserve margins tightened as part of a seasonal capacity construct.

Reducing the winter requirement would correspond to increasing the allowable reliability risk in the winter season from nearly zero under the current construct to a modest level of 0.01–0.03 loss of load events (LOLE), or 10–30% of the annual target. To maintain the "1-in-10" (or 0.1 LOLE) annual target, the summer requirement would increase by 433–1,461 UCAP MW.

Figure 1
Summer and Winter Procurement Under the Annual Capacity Market in 2020/21
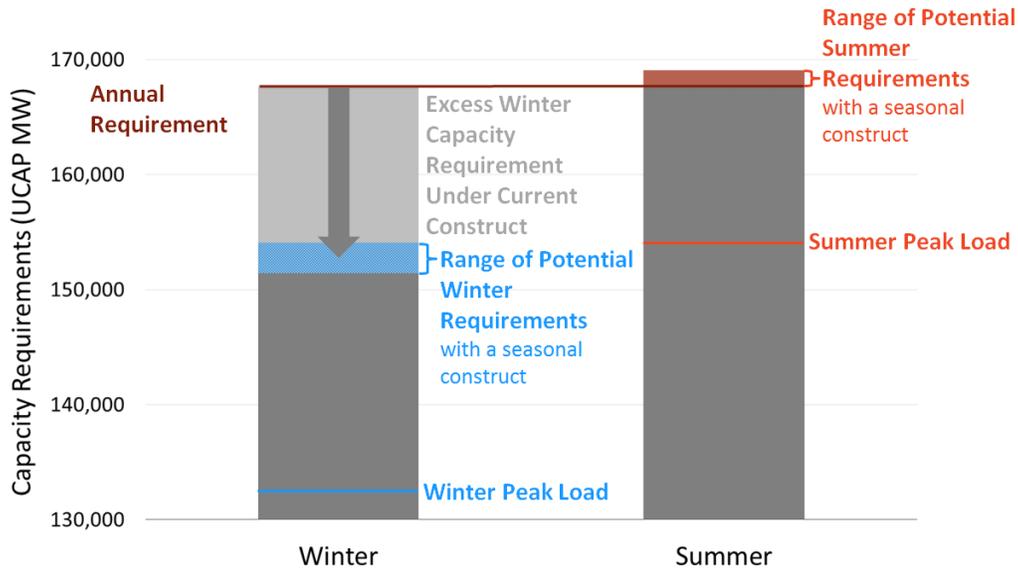
Sources and Notes:
   Annual reliability requirement and summer peak load are from the 2020/21 RPM BRA Planning
      Period Parameters. Reliability requirement includes fixed resource requirement.
   Winter peak load is from the 2017 PJM Load Forecast Report, p. 57.
   Potential winter/summer requirements with a seasonal construct are based on Scenario 5A of
      PJM's Winter Resource Adequacy with 90/10, 80/20, and 70/30 summer/winter LOLE.

B.   MANY SEASONAL RESOURCES ARE UNDERVALUED OR EXCLUDED

The current annual capacity market design is largely developed around an assumption that capacity is annual in nature, and that most capacity suppliers will have similar capacity value in both summer and winter seasons. Most capacity resources that have different capacity ratings in summer and winter seasons are awarded the lower of the two capacity ratings, although this rule is not uniformly applied to all resource types. As a partial solution to enabling seasonal resources with very different summer and winter capacity ratings, PJM has adopted a seasonal matching mechanism. However, this matching mechanism is not open to all resource types and has so far enabled participation of only a small fraction of the seasonal resources within the PJM footprint.

The current approach to accommodating seasonal resources results in a variety of inconsistencies and inefficiencies for different resource types, with the challenges being most acute for resources that have significantly different capacity value across the two seasons:

- **Summer Demand Response:** PJM's current approach excludes summer-only demand response from participation, except when matched with winter capacity. This

inefficiently restricts participation because: (a) matching should not be required since the winter need is much lower, as discussed above; (b) matching opportunities are artificially limited by thermal generators not being allowed to offer their higher winter ratings for matching; and (c) split payments between matched resources understate the reliability value provided by summer-only resources. Consequently, only 289 MW of summer-only demand response cleared in the last PJM auction, leaving 1,191 MW of offered summer-only demand response uncleared.[5] Furthermore, we expect that a large additional quantity of potential summer demand response did not even offer into the auction due to under-remuneration and restricted participation opportunities. Participation levels in the 2019/20 auction that did admit summer-only DR as Base capacity indicate an additional 4,300 MW of summer-only demand response potential that was not offered into the last PJM auction.[6] Thus the total excluded summer-only demand response could be 1,200 to 5,500 MW based on past participation, and potentially more in the future.

- **Summer Energy Efficiency:** Summer-focused energy efficiency programs are excluded or under-remunerated in PJM, with the same challenges as summer demand response. In the last BRA, 300 MW of summer energy efficiency was offered but did not clear.[7] There may be additional summer-focused energy efficiency that remained unoffered.

- **Wind:** Wind resources are allowed to sell their summer UCAP rating into the capacity auction as annual capacity. Wind resources with higher winter ratings are also allowed to offer an additional quantity of winter-only capacity that can be aggregated with summer-only capacity. The total quantity of this matching in the last capacity auction from wind resources amounted to only 383 MW, or only 37% of the total 1,047 MW of winter-only wind capacity that likely exists in the PJM region, leaving 664 UCAP MW of wind winter-only capacity not offered in the most recent auction.[8] Over time we expect

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[5] See PJM, 2020/21 RPM Base Residual Auction Results, p. 11.

[6] The 4,300 MW is approximately the difference between the 5,772 MW of cleared capacity as Base Capacity demand response in the 2019/20 auction and the 1,480 MW of offered capacity as Summer-only demand response in 2020/21. See PJM, 2019/2020 RPM Base Residual Auction Results, p.14. Note that it is possible that some of the prior Base Capacity demand response converted to Capacity Performance that cleared in the most recent auction, but not likely very much of the prior Base demand response that had offered as "Base Capacity-Only" (other demand response resources that cleared as Base Capacity demand response had offered a Capacity Performance alternative at a higher price; these are more likely to have converted to Capacity Performance in the most recent auction that excluded Base and severely limited participation by summer-only demand response).

[7] See PJM, 2020/21 RPM Base Residual Auction Results, p. 11.

[8] To estimate the unoffered wind winter-only capacity in the last auction, we first calculate the winter wind UCAP if all annual wind cleared capacity (504 UCAP MW) had offered its winter capacity at the maximum allowed winter rating (40%) to the standard summer rating (13%). This leads to 1,552 UCAP MW available winter wind capacity. Then we subtract the 504 MW cleared annual capacity and 383 MW of cleared winter-only capacity, resulting in 664 UCAP MW of unoffered wind winter

that wind participation in the seasonal matching program would likely increase even under the current design, though the eventual participation rate may not be at an efficient level unless winter/summer prices are corrected (see the following section).

- **Solar:** Solar resources provide greater capacity value in summer than winter. Unlike summer-only demand response, PJM allows solar resources to participate seasonally (with matching) or annually. However, limited matching opportunities restrict seasonal participation. When participating as annual resources, they must absorb the risk of performance penalties during any supply shortages during winter peaks. This discourages participation, as evidenced by offers decreasing by 210 UCAP MW or 63% between the 2019/20 and 2020/21 Base Residual Auctions even as planned solar installations grew.[9]

- **Thermal Generation:** Combustion turbines (including the CTs within CCs) have substantially higher winter than summer capacity ratings, and other thermal generators have slightly higher winter ratings. Yet only the lower summer rating is accounted for as qualified capacity, and the additional winter capacity is not allowed to engage in seasonal matching. On a fleet-wide basis, this amounts to approximately 9,500 MW of winter capacity supply that is excluded from capacity market participation.[10]

- **Seasonal Imports/Exports:** Seasonal capacity imports are not readily incorporated into the PJM capacity market. Capacity importers must have firm pseudo-tie arrangements for the full planning year in order to sell capacity into PJM.[11] This precludes opportunities for seasonal reserve sharing arrangements such as summer-only imports from winter-peaking regions that could have the potential to reduce total capacity costs across both regions.[12] Seasonal exports are similarly difficult because suppliers within the PJM region would have to lose an entire year of capacity revenue in order to export capacity to a neighboring system for just one season. Enabling seasonal capacity imports and exports has the potential to enable efficiency gains across multiple neighboring systems, as already enabled in NYISO, proposed in Ontario, and discussed in MISO.[13]

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only capacity in the last auction. Maximum winter rating is informed by the PJM RPM hotline, while the summer rating is reported in 2020/21RPM BRA p. 13.

[9]   See PJM, 2020/21 RPM Base Residual Auction Results, p. 13 and 2019/20 RPM Base Residual Auction Results p. 16.

[10]   We estimate the higher winter capacity of thermal generation by using the NERC summer and winter capability ratings data compiled by ABB Energy Velocity to estimate the winter to summer ICAP ratio for each fuel type and applying this to the cleared summer UCAP from the 2007/08 - 2020/21 BRAs.

[11]   See PJM, Manual 12, Section F.2 Generation Dynamic Transfer Business Rules, p. 96.

[12]   Although this type of reserve sharing arrangement does not have a large historical precedent between PJM and other neighboring regions (which are primarily summer-peaking), there are many examples of this type of sharing across the US and between US and Canadian systems.

[13]   See NYISO ICAP Manual Section 4.9, IESO Incremental Capacity Auction Phase 2, and MISO Seasonality Conceptual Design and Business Rules.

- **Mid-Year Entry/Exit:** Resources entering or exiting the PJM market in the midst of a planning year are either excluded for the entire planning year or else assessed deficiency penalties for the months of non-delivery. Breaking the planning year into two seasonal segments would at least partly address this issue, for example by allowing a resource to supply capacity for the entire summer season before retiring at the start of winter.

The nature of seasonality concerns differ by resource type, but on an aggregate fleet-wide basis result in a significant quantity of over-supply or undervalued supply in both seasons, as illustrated in Figure 2. In the summer season, approximately 1,700 to 6,000 MW of summer-only demand response, energy efficiency, and solar supply is either not offered or not cleared in the capacity auction. The current seasonal matching approach provides a partial solution to these seasonality challenges, but only 398 MW out of a total 2,068 MW of summer-only capacity that offered found a winter match in the auction for 2020/21.[14] In the winter season, excess capacity from wind and thermal resources that is either not offered or not allowed to participate amounts to over 10,000 MW of excess winter supply (which is above and beyond the excess procurement due to a flat annual reliability requirement).

Figure 2
Undervalued or Excluded Seasonal Capacity Under PJM's Annual Approach
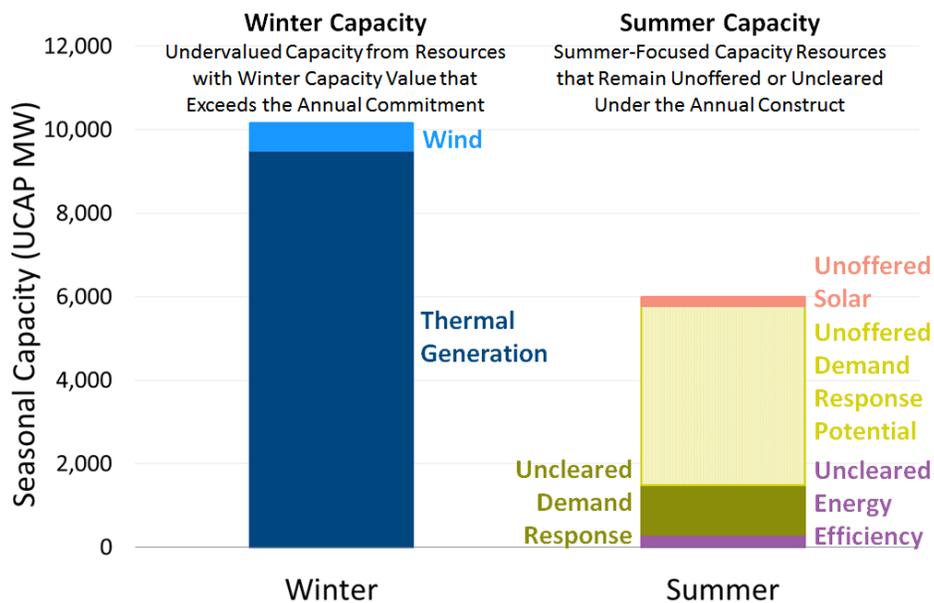
Sources and Notes:
Uncleared energy efficiency and demand response: difference in offered and cleared of each resource type in the 2020/21 BRA.
Unoffered demand response potential: difference of demand response cleared as base capacity in 2019/20 BRA and summer-only demand response offered in 2020/21 BRA.
Unoffered solar resources: difference between solar resources cleared as base capacity in 2019/20 BRA and solar resources cleared in 2020/21 BRA.
Undervalued thermal generation: see footnote 10; undervalued wind resources: see footnote 8.

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[14] See PJM, 2020/2021 RPM Base Residual Auction Results, Table 3C.

C. Prices Do Not Reflect Marginal Costs for Seasonally-Matched Resources

The current approach to seasonal matching awards the same price to summer and winter resources on a daily basis, *e.g.*, in the last auction awarding the same system-wide clearing price across the six summer and six winter months.[15] This approach results in under-payment to the more valuable summer-only supply and over-payment to less valuable winter-only supply, and for three reasons: (1) winter supply is artificially restricted from offering in the auction (see above); (2) winter demand is artificially large compared to the winter need (see above); and (3) the price formation approach does not consider the differentiated marginal value of incremental summer versus winter capacity.

To illustrate the disconnect between pricing and marginal cost of supply between seasons, consider a case where summer capacity supply is more expensive than winter supply but the matched summer and winter resource is cost effective (but marginal) on an aggregated basis.[16] The current PJM matching algorithm would use the average of the summer/winter offer prices to set the annual capacity market price. This results in clearing the least-cost mix of offers and setting annual prices at the efficient level. However, an inefficiency is introduced because the summer and winter capacity resources are each awarded the same price on a daily basis (or half of the total annual payment). This results in the higher-cost summer resource being paid less than its offer price, introducing the possible need for uplift payments not just for the marginal price-setting resource but also for the summer component of a number of infra-marginal matched resources. For winter resources, this results in over-payment. A more efficient price outcome would be to set summer and winter prices based on the offer price for the marginal price-setting resource in each season (which would average to the annual price).[17]

II. Key Elements of a Cost-Effective Solution

Reliability needs throughout the year could be met more cost effectively by fully recognizing differences in seasonal needs and differences among resources' seasonal capabilities and costs. An

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[15] See FERC Docket No. ER17-367-000, Order on Tariff Filing, February 23, 2018, p.8.

[16] For simplicity in this discussion, we consider only a case in which summer supply is more expensive than winter-only supply, for example in a case with a summer resource offering at $125/MW-day being matched with a winter resource offering at $75/MW-day to participate as an aggregated annual resource at $100/MW-day. The opposite case could also occur if winter supply were more restricted or more expensive than summer supply (as may have been the case in the last capacity auction). If the various other adjustments to reduce winter requirements and increase winter supply were enacted, we expect that summer would prove to be the tighter season in PJM.

[17] This same number could also be calculated based on the shadow price for meeting the summer and winter needs, or increase to the objective function achieved by adding 0.1 MW of summer-only or winter-only supply in each location.

auction mechanism could then set prices and sort out the best overall solution, as long as it incorporates the following three key design elements to:

- Allocate PJM's annual reliability target to summer and winter in way that is economically rational;

- Enable resources to participate based on their separate summer and winter capabilities and costs, while still retaining the ability to offer on a strictly annual basis; and

- Send efficient price signals that accurately reflect the fundamentals of supply and demand each season, and structure cost allocation to enable load serving entities to see seasonal price signals.

These three key elements are not addressed well by the existing construct, as discussed above. Below we elaborate on these key elements. Section III will then assess how well these elements were addressed in PJM's prior approach that admitted a certain amount of summer-only capacity. Finally, Section IV will discuss how these three key elements could be incorporated into a two-season capacity construct.

Allocation of Reliability Requirements. PJM's current approach allocates all reliability risk to the summer while over-procuring in the winter. This is not economically efficient because it implies over-procurement of winter capacity that has very little marginal reliability value. A better approach would allow some risk in winter and some in summer. The most rational approach would equalize the marginal cost of capacity per unit of reliability across seasons. That is, the price paid per unit of loss-of-load expectation (LOLE) would be the same for each season. This criterion is analogous to ISO-NE's economically rational criterion for procuring capacity in different *locations* through its Marginal Reliability Impact (MRI) approach to locational capacity demand curves.[18]

This approach would result in different amounts of LOLE allocated to each season if the marginal costs of supporting reliability differ. Because winter peak loads are lower and largely met by annual capacity resources, winter reserve margins will naturally be higher and reliability risks lower. Therefore optimal allocation might place, say, 5-30% of the reliability risk in winter and the rest in the summer in the near term, an allocation that could vary over time (and location) as needs and resources evolve. Perhaps there is a way for an auction to determine the optimum risk allocation endogenously. Even if not, a near-optimal allocation could be established through analysis and periodic updating, particularly in a framework that reveals a transparent capacity price for each season. It would not be difficult to establish a more economically rational allocation than the current approach that allocates all reliability risk to summer.

Resource Participation. An efficient solution should enable seasonal resources to participate based on their separate summer and winter capabilities and costs, and enable annual capacity to participate without risk of clearing in only one season. Summer-only demand response and solar

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[18]   See FERC Approval of ISO-NE Proposed MRI Zonal Demand Curves, June 28, 2016.

resources should be able to participate based on their ability to help meet summer reliability needs; wind resources should be allowed to offer their higher winter capacity to help meet winter reliability needs; and thermal generation with higher winter ratings but varying cost of firming up their winter performance should be able to offer at different prices to meet annual and winter needs respectively. This is not what PJM's current construct does.

Seasonal Pricing. Unlike the current construct that offers no price to unmatched resources and splits capacity payments evenly between matched resources, a more efficient construct would send every resource price signals that reflect marginal reliability values and marginal costs. In other words, seasonal prices should reflect supply and demand fundamentals. Only then can the market sort out an efficient solution.

III. PJM's Prior Maximum Summer-Only Design Approach Missed Some of the Key Elements

The FERC notice asks for comments on "the advantages and disadvantages of (a) procuring this capacity by using annual and summer-only capacity products in a single auction, as PJM did in the past, versus (b) creating two distinct auctions, and procuring summer capacity in one auction and non-summer capacity in the other."[19] We discuss here PJM's prior approach and in the next section a two-seasonal approach.

PJM's prior approach set a total annual requirement according to the capacity demand curve. Most capacity had to be annual, but some could be summer-only, subject to a maximum of 9.3% in the forward auction for 2017/18.[20] The cap was established based on a reliability study that allowed 0.01 LOLE in winter (in addition to 0.1 in summer, for a total of 0.11). PJM's prior approach at least partially incorporated the key elements identified above to cost-effectively meet seasonal needs: it recognized different seasonal requirements; it allowed summer-only resources to participate; and it provided differentiated price signals for summer-only and annual capacity. Reverting to such a construct could address some (but not all) of the shortcomings with PJM's current approach. Several relatively straightforward enhancements to the prior approach would be to conduct an economic re-examination to establish a more efficient allocation of reliability risk in each season, and enable a broader set of summer-only resources to participate. However, other shortcomings of the prior approach could prove to be intractable.

The prior PJM approach is not fully efficient because it does not account for variations in resources' winter capabilities. Wind resources would not be compensated for winter capacity in excess of summer ratings. Thermal resources would not be recognized for higher winter ratings of 9,500 MW. We understand that PJM's reliability study used to determine summer-only-capacity limits does not recognize higher winter capacity ratings for which generation owners

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[19] See FERC, Notice of Request for Comments and Technical Conference, March 16, 2018.

[20] See PJM, 2017/18 BRA Planning Parameters.

have not made an annual commitment, except to the limited extent generation owners may indicate higher ratings in the GADS data against which their outage rates are measured.

In addition, the "maximum summer-only" limit works like a vertical demand curve in the auction, not a sloped demand curve. The benefits of a sloped demand curve have long been recognized by PJM and the Commission. The maximum constraint introduces one-way (downside) price volatility for summer-only resources. Even under tight market conditions when the region is paying high prices for annual supply, the maximum summer constraint could result in very low prices and fail to clear summer-only resources that offer 90% of the reliability value of annual resources.

In the long run, the inefficiency with this approach may become more pronounced with more renewable penetration and potentially higher winter peak load (e.g., electrification of heating). As such, a more seasonal approach will be superior, as described in the next section.

IV. A Co-Optimized Two-Season Capacity Market Would More Efficiently Meet Seasonal Capacity Needs

One solution that would incorporate all of these key design elements would be a comprehensive two-season capacity market that reflects the underlying supply and demand fundamentals in each season. Under a two-season capacity market construct, summer and winter would have separate capacity requirements, demand curves, resource ratings, and clearing prices. This construct would achieve significant societal benefits on the order of $100-600 million per year by fully enabling existing and new seasonal resources to more accurately and cost-effectively meet each season's capacity needs.

A. A SEASONAL CONSTRUCT COULD MORE ACCURATELY REPRESENT BOTH SUPPLY AND DEMAND

Under a two-season capacity market construct, summer and winter would have separate capacity requirements and associated demand curves. Each season's demand curve would reflect the needs of that season (with relative LOLE targets rationally allocated seasonally as discussed above). Every resource would have separate capacity ratings for each season.

In comparison to the current construct, a two-season construct could more accurately represent each supply resource's capabilities by awarding a summer and winter capacity value based on its seasonal output level and outages. Thermal generators and wind would have higher capacity ratings in winter; solar would have higher capacity ratings in summer. Some resources such as summer-only demand response would only have a capacity rating in summer, and would not participate in the winter season. Capacity sellers could offer at different prices in different seasons depending on the nature of their availability (and associated Capacity Performance penalty exposure) and the costs of firming up performance in each season. Altogether, the increased specificity of resource capabilities and costs across seasons would enable the auction to find a more efficient solution than is possible under the current construct.

On the demand side, a seasonal construct would allow PJM to set separate seasonal requirements to reflect seasonal peak loads and a more cost-effective LOLE allocation between seasons, as discussed above. The summer and winter demand curve pricing points would also have to be established, following similar principles of economic rationality and the relative costs of meeting the reliability requirement in each season. For example, suppose meeting summer needs requires investment in new gas-fired generation, whereas meeting winter needs depends primarily on firming up annual resources' winter fuel supplies. The summer demand curve could concentrate annual Net CONE into half the year (raising the reference price for the summer VRR curve), and the reference price in winter could reflect the costs of firming up the reference resource's winter fuel supply. As a result, the winter curve could be downshifted as well as left-shifted.[21]

B. CO-OPTIMIZED AUCTION CLEARING WOULD PRODUCE MORE EFFICIENT PRICES WITHOUT INTRODUCING INVESTMENT UNCERTAINTY

The procurement of resources for summer and winter would be conducted in one auction that co-optimizes procurement across seasons, as follows: suppliers would submit their offers as summer-only, winter-only, and/or annual supply resources. Summer-only and winter-only resources would offer the minimum $/MW-day needed to take on a capacity obligation over the six-month period. Annual resources would offer the total annual revenue requirement needed to take on a capacity obligation in both summer and winter.[22]

The market would determine the resource procurement through a co-optimization that maximizes social welfare across the two seasons as illustrated in Figure 3. In this example, the tighter summer supply-demand balance sets the clearing price at a somewhat higher price, e.g. $150/MW-day for the summer period, and the longer winter supply-demand balance sets the clearing price at a lower level, e.g. $50/MW-day. Annual resources would earn the winter and summer prices in each respective season, or $100/MW-day over the year. Winter and summer

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[21] Fully optimizing the market so that market clearing prices always produce the same marginal cost per unit of reliability gained in each season likely would not be achievable unless the mechanism for enforcing that price and quantity substitution between summer and winter supply were incorporated into the auction clearing. The approach we describe here is a more simplified implementation that would achieve the same result on average across years (but not in every year) via periodic adjustments to the demand curve position and price levels.

[22] We express this annual offer in terms of total dollar payment rather than a $/MW-day price because it can reflect any combination of summer and winter prices, as long as the (summer price) × (summer UCAP) plus (winter price) × (winter UCAP) is high enough to cover the resource's annual net going-forward offer. Annual resources would also have the option to offer at a different price to clear based on a 6-month summer-only or winter-only capacity obligation. This would allow for a seasonal export or mothballing arrangement. If offering under more than one arrangement, the offers would be treated as contingent supply offers in that a single supply resource could clear as summer-only, winter-only, or annual (but never in ways that would double-count supply).

resources would clear if they had offered below the respective season's clearing price; annual resources would clear as long as they offered below $100/MW-day on an annual basis.[23]

As a result, resources would earn different seasonal prices that reflect the supply and demand balance in each season. This would send efficient price signals to for resource investment and retention in each season, as well as providing more efficient price signals to customers.

Figure 3
Co-Optimized Seasonal Capacity Auction Clearing
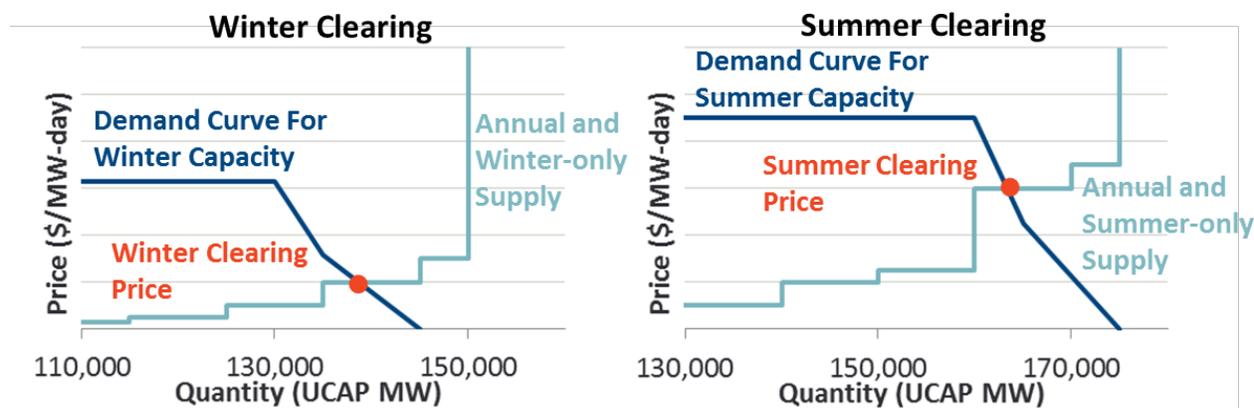
C. Adopting a Two-Season Market Could Reduce Societal Costs by Approximately $100–600 Million per Year

The greater efficiency from adopting a seasonal capacity market design through lower winter procurement, full utilization of seasonal supply, and more efficient price signals can help PJM to reduce costs while still meeting reliability standards. In Table 1 we provide an indicative, order-of-magnitude estimate of potential societal cost savings from a seasonal capacity auction based on the following assumptions largely reflecting current market conditions:

- **Reduction in Annual Capacity Needed to Meet Winter Requirements.** A two-season capacity market would reduce the quantity and total cost of annual capacity through:
  - *Lower Winter Capacity Requirement:* Based on PJM's Scenario 5A with 90/10 allocation of summer/winter LOLE, we assume the winter reliability requirement

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[23] When drawn as part of the total summer or total winter supply curve, an annual resource would be considered at its "effective" offer price in each season. Consider an annual resource that offered at $90/MW-day in this example; the "effective" offer price in the winter seasons depends on the final price earned in summer. Knowing that the summer price is $150/MW-day, this annual resource would require another $30/MW-day winter price in order to earn the total $90/MW-day annual revenue requirement. Thus the annual resources as illustrated in the figure should be interpreted as the "effective" price in each season (once the clearing price in the other season is known).

would be reduced by 13,538 UCAP MW compared to the current construct.[24] This reduces the amount of annual capacity needed.

- *Liberated Winter-Only Capacity:* We assume that a seasonal construct would liberate the currently un-counted 9,500 MW higher winter capacity ratings from thermal generation to participate as winter-only capacity.[25] We further assume that the 664 MW winter-only capacity from wind that was unoffered or uncleared in the latest auction is liberated. This reduces the amount of annual capacity needed to meet winter needs.

- *Cost Savings from Procuring Less Annual Capacity:* We assume an avoided cost of $115/MW-day of annual capacity based on the average clearing prices in PJM RTO for the last three BRA auctions (2018/19, 2019/20, and 2020/21).[26] This will be partially offset by replacing the annual resources with summer-only resources.

- **Replacement by Summer-Only Capacity:** Recognizing lower winter requirements and increased winter capacity significantly reduces the amount of annual capacity needed creates an opportunity for summer-only capacity:

- *Liberated Existing Summer-Only DR Capacity:* We assume a seasonal construct would admit 5,500 MW of low-cost summer-only demand response that cleared in 2019/20 as summer-only (Base Capacity) product but did not clear in 2020/21, as discussed in Section I.B. We assume a cost of $33/MW-day, based on ISO New England's estimate of the cost of demand response for large commercial and industrial customers that it uses for its Offer Review Trigger Price (ORTP).[27]

- *Liberated Existing Solar PV Capacity:* We assume 210 MW of incremental solar capacity that cleared in the 2019/20 BRA but not in the 2020/21 auction.[28] Since this capacity presumably already exists or is under development, we assumed zero cost of providing summer capacity.

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[24] Footnote 4 above explains our rationale for selecting this scenario.

[25] In our cost savings estimate, we assume PJM does not account for the full 9,500 MW of higher winter capacity from thermal generation in its winter reliability assessment. The cost saving could be slightly overstated to the extent some resources' winter capacity is already counted. We understand that PJM's winter reliability analysis accounts for higher winter ratings, but only to the extent that generation owners specify higher ratings in their GADS data submitted to PJM. We expect that these ratings typically reflect the summer ratings that resources commit to provide (and be paid for) in the current annual construct. A seasonal construct, where resources could be rated and committed and compensated seasonally, would encourage full recognition of winter capabilities.

[26] See PJM, 2020/21 BRA Results, p. 6.

[27] See ISO-NE ORTPs for FCA 12, slide 25. The estimated cost for commercial and industrial load management and/or previously installed demand resources is $1.008/kW-month, which equates to $33/MW-day.

[28] See footnote 9 and footnote to Figure 2 for estimation explanation.

- *Liberated Existing Energy Efficiency:* We assume 300 MW of incremental energy efficiency capacity at $0 cost, grounded in the same data and reasoning as for solar.
- *Generation Relieved of Having to Firm up Winter Performance:* We assume that the remaining 17,692 MW of summer-only capacity replacing annual capacity would derive from annual-type resources that can operate with lower costs because they no longer have to firm up their winter performance. We assume the avoided cost is approximately $15/MW-day (from $115 for annual commitments down to $100/MW-day for summer-only commitments) based on the price difference between Base Capacity and Capacity Performance products observed in the 2018/19 BRA.[29]

- **Increase in Summer Requirement:** PJM's Scenario 5A with 90/10 LOLE allocation indicates that the summer requirement would increase by 433 UCAP MW. We assume adding such capacity would cost $100/MW-day, similar to our assumption for other summer capacity not met by low-cost summer-only resources.

Based on these assumptions and as summarized in Table 1, we estimate that a seasonal capacity market could reduce societal costs by approximately $270 million per year on a sustained basis. Savings could increase over time as the market evolves based on the opportunities presented. But there is substantial uncertainty surrounding the nature and quantities of participating resources, and their costs. By adjusting our assumptions within a reasonable uncertainty range, we estimate that the societal benefits could range from $100 to $600 million per year.[30]

We did not estimate customer benefits associated with temporary changes in prices and associated wealth transfers from suppliers. Short-run customer benefits could be substantially higher than societal benefits if clearing prices decreased with the introduction of more efficient seasonal construct and the inclusion of many more low-cost seasonal resources.

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[29] See PJM, 2018/19 BRA Results, p. 2.

[30] The low case reflects only 1,200 MW of low-cost summer-only capacity, corresponding to the amount offered but not matched and cleared in the 2020/21 BRA, and a $10/MW-day cost savings per MW of capacity relieved of firming winter performance. The high case reflects 11,000 MW of low-cost summer-only capacity (almost twice as much as the base estimate), a $165/MW-day cost of annual capacity (based on the highest RTO price seen in the past three BRAs), and a $20/MW-day cost savings per MW of capacity relieved of firming winter performance.

Table 1
Indicative Societal Cost Savings Estimate

	Quantity (UCAP MW)	Cost ($/MW-day)	Cost Impact ($millions/year)
Reduction in Annual Capacity Needs	**(23,702)**	**$115**	**($995)**
Lower Winter Requirement	(13,538)	$115	($568)
Liberated Thermal Winter-only Capacity	(9,500)	$115	($399)
Liberated Wind Winter-only Capacity	(664)	$115	($28)
Replacement by Summer-Only Capacity	**23,702**	**$82**	**$712**
Liberated Existing Summer-only DR	5,500	$33	$66
Liberated Existing EE	300	$0	$0
Liberated Existing Solar	210	$0	$0
Generation without Firm Winter Delivery	17,692	$100	$646
Increase in Summer Requirement	**433**	**$100**	**$16**
Net Change in Societal Costs			**($267)**

D. THE TWO-SEASON CONSTRUCT WOULD FACILITATE EFFICIENT TRANSFORMATION OF THE FLEET AND LOAD PATTERNS

The resource mix within PJM's footprint has already undergone a significant transformation with the incorporation of a large number of non-traditional resources that do not always follow traditional assumptions regarding seasonal availability. A two-season capacity market would more efficiently and effectively utilize the full capability of these new resources, as well as fully utilizing the seasonal potential of thermal generation resources, seasonal imports/exports, and mid-year entry and exit.

Over the coming years, we expect that the resource mix will continue to evolve in potentially unanticipated ways and continue to incorporate greater quantities of non-traditional resources. There could also be significant changes in load patterns such the electrification of transportation and heating loads that may cause a deviation in the traditional relationship between summer and winter peaking needs. In this context, the flexibility of a two-season auction could become increasingly valuable. The two-season approach would continue to rely on basic economic principles of supply and demand to reflect reliability needs, and the ability of both traditional and new resources to meet those needs most cost-effectively.

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