COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC TARIFF FILING OF BIG RIVERS ELECTRIC COPRORATION FOR APPROVAL OF PROPOSED CHANGES TO ITS QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES TARIFFS	**))))))**	**Case No. 2023-00102**

PETITION FOR REHEARING

I. Introduction

Comes Big Rivers Electric Corporation ("*Big Rivers*"), by counsel, and respectfully petitions the Kentucky Public Service Commission ("*Commission*") pursuant to KRS 278.400 for rehearing of its December 15, 2023, Order (the "*December 15 Order*") in this matter on the grounds that the December 15 Order is arbitrary, unlawful, unreasonable, unreasonably discriminatory, and unsupported by the evidence in violation of KRS Chapter 278 and Sections 2 and 3 of the Kentucky Constitution. More specifically:

A. the rates approved by the Commission in the December 15 Order are arbitrary, unreasonable, and unsupported by the evidence;

B. the rates approved by the Commission in the December 15 Order arbitrarily, unreasonably, and without evidence treat the capacity from a QF Customer under a two- or five-year contract equal to the capacity from an NGCC unit with a useful life in the decades;

C. the requirement in the December 15 Order to offer two- and five-year contract terms is arbitrary, unreasonable, and unsupported by the evidence;

D. the December 15 Order unreasonably and unlawfully requires other customers on the Big Rivers system to pay higher rates to subsidize customers installing their own generation;

E. the December 15 Order unreasonably and unlawfully denies Big Rivers the right to collect fair, just, and reasonable rates by requiring Big Rivers to subsidize customer-owned generation at arbitrary rates;

F. the December 15 Order is arbitrary and unsupported by evidence because it fails to provide rates for 2029 and beyond; and

G. the December 15 Order is arbitrary and unreasonable because there is no evidence in the record supporting the rates adopted in that Order.

Each of these issues is discussed in more detail below.

II. <u>Rehearing Requests</u>

A. The rates approved by the Commission in the December 15 Order are arbitrary, unreasonable, and unsupported by the evidence.

In the December 15 Order, the Commission requires Big Rivers to offer two- and five-year contracts to retail customers that qualify under the QF tariff ("*QF*

Customers").[1] But instead of using two- and five-year bilateral capacity purchases as a proxy for Big Rivers' avoided capacity costs, the Commission leaps to the conclusion that Big Rivers should be required to purchase a QF Customer's capacity **now** based on the projected cost of a natural gas combined cycle ("NGCC") unit that will not be built until at least 2029.[2]

In making this leap, not only does the Commission fail to point to any evidence that the capacity offered by QF Customers will ever enable Big Rivers to avoid or delay constructing the NGCC unit, the Commission fails to show in particular that Big Rivers can avoid the cost of an NGCC unit in 2024 or 2025 or 2026 or 2027 or 2028, since no NGCC unit is planned or could be feasibly be constructed in those years.

807 KAR 5:054 requires a QF rate schedule to be based on avoided costs, which are the "incremental costs to an electric utility of electric energy or capacity or both which, ***if not for the purchase from the qualifying facility***, the utility would generate itself or purchase from another source."[3] A utility's "avoided capacity cost is determined at the time the utility incurs the obligation to purchase capacity from a QF...."[4] However, the utility's "avoided capacity cost may later change as additional capacity acquisitions are avoided…."[5] Thus, even if Big Rivers

[1] December 15 Order at p. 12.

[2] *See id.* at p. 8.

[3] 807 KAR 5:054 Sections 1(1), 7(4) (emphasis added).

[4] 85 Fed. Reg. 54,684 (Sept. 2, 2020).

[5] *Id.*

may build new generation in the future, absent a showing that any planned generation is being avoided or delayed ***as a consequence of purchasing from the QF***, Big Rivers' avoided cost now is the cost it can avoid now by purchasing a QF's Customer's capacity.

At a minimum, for years prior to when an NGCC unit could feasibly be constructed, no QF Customer is enabling Big Rivers to avoid the NGCC generator costs. Instead, for those years, Big Rivers would purchase the capacity otherwise provided by the QF Customer in the MISO Planning Resource Auction ("*PRA*").[6] As such, in the near term, the cost to construct an NGCC in 2029 is not a reasonable proxy for Big Rivers' avoided capacity cost, and the rates approved by the Commission in the December 15 Order are therefore arbitrary, unreasonable, and unsupported by the evidence.

Moreover, in the longer term, absent evidence that a QF Customer's capacity will actually enable Big Rivers to avoid or delay the construction of an NGCC, then the NGCC cost is still not a reasonable proxy of Big Rivers' avoided costs. A utility's avoided cost is the upper limit on QF rates allowed by PURPA.[7] This limit "implements Congress's intent that QFs not be subsidized. It ensures that the purchasing utility cannot be required to pay more for power purchased from a QF

[6] Big Rivers' response to Item 7 of the Commission Staff's First Request for Information.

[7] *See Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 413, 103 S. Ct. 1921, 1928, 76 L. Ed. 2d 22 (1983).

than it would otherwise pay to generate the power itself or to purchase power from a third party."[8]

Even though Big Rivers' generation planning includes the construction of a new NGCC, utilizing that cost as Big Rivers' avoided cost for purposes of QF capacity purchase rates would be appropriate ***<u>if and only if</u>*** the QF Customers' capacity causes Big Rivers to be able to avoid or delay the new unit. As FERC has explained:

> Certain commenters expressed concern that, ***<u>when a purchasing electric utility is not avoiding the construction or purchase of capacity as a consequence of entering into a contract with a QF</u>***, under the NOPR's proposed rules a state could limit the QF's contract rate to variable energy payments. However, ***<u>in that event, the only costs being avoided by the purchasing electric utility would be the incremental costs of purchasing or producing energy at the time the energy is delivered</u>***.[9]

---

[8] 85 Fed. Reg. 54,642 (Sept. 2, 2020); *see also* 85 Fed. Reg. 54,650 (Sept. 2, 2020) ("If there were any doubt from the statutory language that incremental costs (avoided costs) are intended to be a hard cap on QF rates, such doubt is dispelled by the Conference Report to PURPA, which provided: 'This limitation on the rates which may be required in purchasing from a cogenerator or small power producer *is meant to act as an upper limit on the price* at which utilities can be required under this section to purchase electric energy.' The Conference Report also described the reason for the avoided cost cap on QF rates. 'The provisions of this section *are not intended to require the rate payers of a utility to subsidize* cogenerators or small power produc[er]s'") (citations omitted) (emphasis in original).

[9] 85 Fed. Reg. 54,683 (Sept. 2, 2020) (citations omitted) (emphasis added); *cf.* 45 Fed. Reg. 12,216 (Feb. 25, 1980) ("If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rates for such a purchase will be based on the avoided capacity and energy cost"); 45 Fed. Reg. 12,227 (Feb. 25, 1980) ("If purchases from qualifying facilities enable a utility to defer or avoid these new planned capacity additions, the rate for such purchases should reflect the avoided costs of these additions"); 85 Fed. Reg. 54,681 (Sept. 2, 2020) ("Capacity costs, as relevant here, include the cost of constructing the capacity being avoided by purchasing utilities as a consequence of their purchases from QFs").

Thus, the cost to construct a new NGCC unit is only representative of Big Rivers' avoided costs if capacity from QF Customers would actually cause Big Rivers to delay or avoid that construction.

There is currently only one QF Customer that sells its capacity to Big Rivers.[10] That customer is under 5 MW of generation.[11] The record is devoid of any evidence that that customer's capacity will delay or avoid the construction of a new 635 MW NGCC unit.

In a recent Order, the Commission denied East Kentucky Power Cooperative's ("*EKPC*") request for rehearing in a case involving EKPC's QF capacity purchase rates. In that Order, the Commission ruled that "if a need for additional capacity arises during the length of a contract it is appropriate to set the avoided capacity costs above $0, even for the periods of time in the contract where there is no need for additional capacity":

> The Commission's decision is further supported by the FERC which, in discussing the establishment of non-zero avoided capacity costs rates over the length of a contract where a utility has no need for additional capacity when the contract begins found:
>
> > [I]f a utility is able to avoid constructing a new generation facility with a capacity cost of $10/MW-month as a result of purchasing power from a QF, its avoided capacity cost is the $10/MW-month capacity cost that it would have been incurred to construct the new facility. Once the utility commences its purchases from the QF, it may not need additional capacity, and its avoided capacity cost for the next QF would drop to $0/MW-month. It would not be appropriate to then reduce the original QF's avoided capacity charge to $0/MW-month, however,

---

[10] *See* Big Rivers' response to Item 1(c) of the Commission Staff's First Request for Information.

[11] Big Rivers' response to Item 1(a) of the Commission Staff's First Request for Information.

> because the only reason that the utility does not need additional capacity is because it already purchased capacity from the original QF in order to avoid the $10/MW-month capacity cost. That is, without the purchase from the original QF, the utility would have incurred a capacity cost of $10/MW-month, and that is the utility's avoided capacity cost for the term of its contract with the original QF. It would be inappropriate, in other words, for avoided cost capacity rates to change after they are first set at the time a LEO (such as a contract) is established.
>
> In the scenario discussed above, if a need for additional capacity arises during the length of a contract it is appropriate to set the avoided capacity costs above $0, even for the periods of time in the contract where there is no need for additional capacity.[12]

The Commission entirely misreads the FERC order it quotes from in that EKPC Order. In FERC's example, the first QF customer's capacity actually enables the utility to avoid the construction of a new generating facility. Therefore, it was appropriate in that example for the customer to receive a capacity payment, and to continue to receive that capacity payment during the length of the contract because the utility actually avoided a $10/MW-month capacity cost the utility otherwise would have incurred "***<u>for the term of its contract with the original QF</u>***." FERC also found it appropriate that a second QF would receive no capacity payment if that QF's capacity would not itself cause the utility to avoid or delay construction.

The FERC order cited by the Commission does not stand for the proposition that a utility can be forced to subsidize a QF even when the QF is not causing the utility to avoid any capacity costs. In fact, the Commission's reading of FERC's

[12] *In the Matter of: Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and its Member Distribution Cooperatives for Approval of Proposed Changes to their Qualified Cogeneration and Small Power Production Facilities Tariff,* Case No. 2023-00153, Order (Dec. 8, 2023), a pp. 7-8 (citations omitted).

order is at odds with the order itself.[13] The FERC order reaffirms that a utility's avoided cost capacity purchase rate would include the cost of a new unit only when the QF enabled the utility to avoid or delay construction of that unit.

In Big Rivers' case, because there is no evidence that any QF has or will enable Big Rivers to avoid constructing a new NGCC unit, the cost of constructing that unit is not a reasonable proxy for Big Rivers' avoided costs. As such, the rates approved by the Commission in its December 15 Order are arbitrary, unreasonable, and unsupported by the evidence.

B. The rates approved by the Commission in the December 15 Order arbitrarily, unreasonably, and without evidence treat the capacity from a QF Customer under a two- or five-year contract equal to the capacity from an NGCC unit with a useful life in the decades.

The Commission states in the December 15 Order, "The Commission reiterates that it has no interest in allowing Kentucky's regulated, vertically integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time."[14] Yet, the Commission fails to point to any evidence showing that depending on two- and five-year contracts for capacity from customer-

---

[13] In the order, FERC held that if a utility went through the proper competitive solicitation, and the utility's self-build option was selected over a QF offer, then capacity rates could be zero. In other words, even when the utility is constructing generation, capacity rates can be zero if the QF's capacity does not enable to utility to avoid any capacity costs. *See, e.g.,* 85 Fed. Reg. 86,687 (Dec. 30, 2020) ("The Commission has already determined, and affirmed in the final rule, that capacity rates can be zero. The possibility of a zero capacity rate does not mean that the Commission has determined that utilities have no obligation to purchase capacity from QFs. It just means that, under our precedent, if a purchasing utility avoids no capacity costs due to the QF purchase, then the avoided cost for capacity will be zero").

[14] December 15 Order at p. 7.

owned renewable generation is in any way equivalent to constructing a base load generating unit that will last for decades.

In the December 15 Order, the Commission adopts the "estimated cost of an NGCC unit in 2029 dollars discounted back to 2024 as the ***proxy*** for BREC's avoided capacity cost."[15] But unless a QF Customer has a legally enforceable obligation ("*LEO*") to provide capacity for a term similar to the life of a base load generating unit, there is no evidence in the record that the cost of constructing a base load generating unit that has a decades-long useful life is a reasonable proxy for the cost Big Rivers avoids by purchasing a QF Customer's capacity over the next two or five years. Instead, the ***actual*** cost Big Rivers avoids by having a two- or five-year contract with a QF Customer is the capacity cost Big Rivers would otherwise incur over that same time frame. Because Big Rivers was not planning to and could not construct an NGCC unit in the next five years, no matter how many QF Customers joined the two existing QF Customers, the cost to construct an NGCC unit is not Big Rivers' avoided cost over that time frame. Even in the long term, absent evidence that QF Customers enable Big Rivers to delay or avoid construction of an NGCC unit, the cost of constructing an NGCC unit in the future is not representative of Big Rivers' actual avoided costs.

Instead, as noted above, Big Rivers procures the capacity needed to fulfill its obligations in the annual MISO PRA. As such, the reduction in capacity Big Rivers must purchase in the MISO PRA as a result of a QF Customer's capacity times the

[15] *Id.* at p. 9 (footnote omitted) (emphasis added).

applicable auction price is Big Rivers' ***actual*** avoided cost. The Commission's apparent belief that short-term contracts for capacity from customer-owned renewable generation can substitute for long-term, base load generating unit is unsupported by the evidence, and therefore, the rates approved by the Commission in the December 15 Order arbitrarily and unreasonably treat the capacity from a QF Customer under a two- or five-year contract equal to the capacity from an NGCC unit with a useful life in the decades.

C. The requirement in the December 15 Order to offer two- and five-year contract terms is arbitrary, unreasonable, and unsupported by the evidence.

As noted above, the December 15 Order requires Big Rivers to offer two- and five-year contract terms to QF Customers.[16] In adopting this requirement, the Commission relies primarily not on evidence presented in this case but on simple citations to cases to which Big Rivers was not a party and that do not apply to Big Rivers.[17]

In its attempt to support requiring two-year contract terms, the Commission also cites 807 KAR 5:054 Section 5(1)(a). But that subsection only applies to electric utilities with more than 500 million kWhs of annual retail electric sales. Big Rivers does not have any retail electric sales, and so, it is arbitrary and unreasonable to rely on that subsection to support a requirement for Big Rivers.

[16] *Id.* at p. 12.

[17] *See id.*

In adopting five-year contract terms, the Commission states, "Additionally, the Commission notes that BREC has indicated that it plans to build additional generation in 2029, which would be approximately five years from the effective date of this Order. Therefore, a five-year term contract option would also be appropriate."[18] But it does not follow that Big Rivers should pay for capacity for the next five years based on the cost of an NGCC unit that will not be constructed for at least five years, especially where there is no evidence that that unit will be delayed or avoided as a consequence of the capacity provided by QF Customers.

A five-year contract term requirement at this time could only be reasonable if the contract was based on the capacity costs that Big Rivers can avoid over the next five years. In that time frame, the only costs Big Rivers can possibly avoid by having a QF Customer on its system are the reduction in capacity costs Big Rivers incurs to purchase capacity in the seasonal MISO PRA. Therefore, the evidence supports using the reduction in MISO PRA costs resulting from the QF Customer's capacity as Big Rivers' avoided capacity cost.

Further, if the MISO PRA is used as Big Rivers' avoided capacity cost, there is no benefit to either Big Rivers or the customer of requiring the customer to enter into a five-year contract versus a one-year contract that renews annually (as Big Rivers proposed in its QF tariff filing). The one-year renewable term aligns with the MISO PRA and enables the QF Customer to determine each year whether to

[18] *Id.*

obligate itself to MISO's requirements.[19] Requiring two- and five-year contract terms is arbitrary, unreasonable, and unsupported by the evidence.

D. The December 15 Order unreasonably and unlawfully requires other customers on the Big Rivers system to pay higher rates to subsidize customers installing their own generation.

KRS 278.170(1) prohibits unreasonable discrimination as to rates or service, but the December 15 Order forces residential, commercial, and small industrial customers on the Big Rivers system to subsidize retail customers who chose to install their own renewable generation. As noted above, the December 15 Order overcompensates a QF Customer by requiring Big Rivers to pay a rate based on the cost of an NGCC unit that will not be constructed until at least 2029, instead of a rate based on the cost Big Rivers avoids in the annual MISO PRA over the two- or five- year term of the QF Customer's contract. That additional cost is passed on to other retail customers on the Big Rivers system through a reduction in the MRSM bill credits those customers would otherwise receive. Thus, the December 15 Order unlawfully and unreasonably discriminates against some customers on the Big Rivers system by requiring them to subsidize the choice of other customers to install their own generation.[20]

The December 15th Order treats Big Rivers as if it is always capacity short and needs to purchase capacity. But this is not the case, as there as seasons when

[19] *See* Big Rivers' response to Item 5 of the Commission Staff's Third Request for Information.

[20] *See* 18 CFR § 292.304(a)(2) ("Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases").

Big Rivers is projected to be short capacity and seasons when Big Rivers is projected to be long capacity.[21]

Under the rates adopted by the Commission, when Big Rivers is short capacity, Big Rivers would be purchasing capacity from the QF Customer at the Commission-approved rates, even though Big Rivers could otherwise purchase that capacity in the MISO PRA. When Big Rivers is long capacity, Big Rivers would be paying the QF Customer at the Commission-approved rates, even though it can only sell its own surplus capacity at the MISO PRA price.

The capacity rates approved by the Commission in the December 15 Order are $33.87/kW-year for 2024, which is equivalent to $92.79/MW-day.[22] The MISO PRA results for Planning Year 2023-24 were $10/MW-day for Summer, $15/MW-day for Fall, $2/MW-day for Winter, and $10/MW-day for Spring.[23] Thus, in Winter, under the Commission-approved rates, assuming Big Rivers is long capacity, it would be paying the QF Customer $92.79/MW-day for capacity at the same time it is selling its own capacity at $2/MW-day. If Big Rivers were to be short capacity, it would be by paying the QF Customer $92.79/MW-day when it could otherwise acquire that capacity in the MISO PRA for $2/MW-day.

---

[21] *See* the Attachment to Big Rivers' response to Item 6 of the Commission Staff's Third Request for Information.

[22] ($33.87/kW-year * 1,000 kW per MW) / 365 days per year = $92.79/MW-day.

[23] *See* the *2023 Planning Resource Auction (PRA) Results*, a copy of which is attached hereto as Exhibit A; Big Rivers' response to Item 3 of the Commission Staff's Second Request for Information in *In the Matter of: An Electronic Examination of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2020 through October 31, 2022*, Case No. 2023-00013;

Clearly, the rates approved in the December 15 Order unlawfully exceed the cost Big Rivers would otherwise incur to purchase the capacity from the MISO PRA but for the purchase of that capacity from QF Customers.[24] Those rates are therefore not fair, just, and reasonable. The approved rates are also unreasonably discriminatory because they require Big Rivers, its Members, and the retail customers in Big Rivers' service area to subsidize QF Customers at rates far in excess of the rates at which Big Rivers can otherwise purchase capacity to meet its needs when it is short or the rates at which Big Rivers can sell its capacity when it is long.

On the other hand, and regardless of whether Big Rivers has capacity shortfalls or has excess capacity, Big Rivers' proposal to use the MISO PRA price as Big Rivers' avoided costs is fair both to the QF Customer and to non-QF customers. Under Big Rivers' proposed capacity purchase rates, whether Big Rivers is long or short on capacity, Big Rivers would purchase capacity from the QF Customer at the exact rate it would otherwise pay to procure that capacity or sell capacity in the MISO PRA. For example, because Big Rivers can purchase capacity or sell its capacity in the MISO PRA for $2/MW-day during Winter 2023-34, then Big Rivers would also pay the QF Customer $2/MW-day for its capacity during that same time

---

[24] *See* 18 CFR § 292.304(a)(2) ("Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases"); *Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 416, 103 S. Ct. 1921, 1929, 76 L. Ed. 2d 22 (1983), at n. 9 ("Of course, even when utilities purchase electric energy from qualifying facilities at full avoided cost rather than at some lower rate, the rates the utilities charge their customers will not be increased, for by hypothesis the utilities would have incurred the same costs had they generated the energy themselves or purchased it from other sources").

frame. Thus, the QF Customer is not forcing other customers to subsidize it, but the QF Customer does receive the same payment for its capacity as Big Rivers' actual avoided cost.

E. The December 15 Order unreasonably and unlawfully denies Big Rivers the right to collect fair, just, and reasonable rates by requiring Big Rivers to subsidize customer-owned generation at arbitrary rates.

KRS 278.030(1) provides, "Every utility may demand, collect and receive fair, just and reasonable rates for the services rendered or to be rendered by it to any person." For the reasons explained in Section II.D above, the December 15 Order unlawfully requires Big Rivers to subsidize customer-owned generation. Capacity provided by a QF Customer reduces the capacity Big Rivers would otherwise procure in the MISO PRA. However, instead of Big Rivers paying the QF Customer the value that customer's capacity realized in the MISO PRA, the December 15 Order requires Big Rivers to pay the QF Customer more than it would have cost Big Rivers to procure the same capacity in the MISO PRA. As such, the December 15 Order unreasonably and unlawfully denies Big Rivers the right to collect fair, just, and reasonable rates by requiring Big Rivers to subsidize customer-owned generation.

F. The December 15 Order fails to provide rates for 2029 and beyond.

The December 15 Order requires Big Rivers to offer five-year contract terms to QF Customers. Any five-year contract entered into in 2024 would extend into 2029. Yet, the Commission only approved rates through 2028.

G. The December 15 Order is arbitrary and unreasonable because there is no evidence in the record supporting the rates adopted in the Order.

The rates adopted by the Commission in the December 15 Order are based on projected cost information Big Rivers filed in a separate case, which is not a part of the record in this proceeding. Further, there is nothing in the record showing how the Commission used those costs to arrive at the selected rates. As such, the December 15 Order is arbitrary and unreasonable because there is no evidence in the record supporting the rates adopted in that Order.

III. <u>Conclusion</u>

Based on the foregoing, the December 15 Order is arbitrary, unlawful, unreasonable, and unsupported by the evidence. As such, the Commission should grant rehearing of the Order, and approve the rates proposed by Big Rivers instead of the rates in that Order.

WHEREFORE, for the reasons set forth above, Big Rivers respectfully requests that the Commission grant the petition for rehearing, and approve the rates proposed by Big Rivers.

On this the 5th day of January, 2024,

/s/ Tyson Kamuf

Tyson Kamuf
Senthia Santana
Big Rivers Electric Corporation
710 West Second Street
Owensboro, Kentucky 42301
Phone: (270) 827-2561
Facsimile: (888) 231-0321
tyson.kamuf@bigrivers.com
senthia.santana@bigrivers.com

Counsel for Big Rivers Electric Corporation

Planning Resource Auction

Results for Planning Year 2023-24

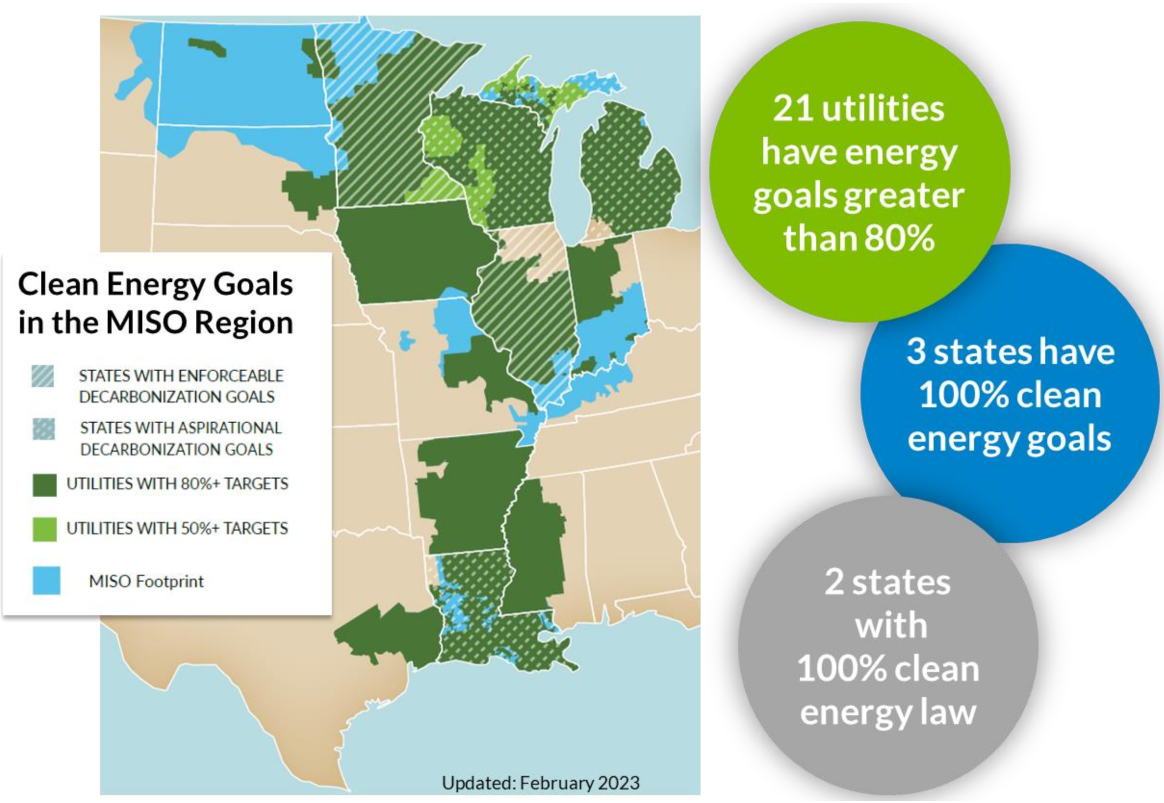
May 19, 2023

Seasonal resource adequacy construct sets the stage for several other key initiatives necessary to ensure a sustainable response to the Reliability Imperative

- The changing resource fleet driven by aggressive member decarbonization strategies continues to dramatically shift the reliability risk profile in our region.

- Coordinated reform of Resource Adequacy, Market Design and Transmission evolution is necessary to ensure continued reliability.

- Implementation of the seasonal construct is one step in the overall work needed to meet the Reliability Imperative.



MISO

Market response to high prices from the 2022 auction helps mitigate Resource Adequacy risk for Planning Year 2023-24

- MISO's seasonal PRA improves reliability planning by identifying requirements, resource accreditation and risks for individual seasons.
- MISO is projected to have adequate capacity to meet resource adequacy requirements for PY 2023-24 at the regional, sub-regional & zonal levels.
  - Auction Clearing Prices are flat across the region:
    Summer: $10, Fall: $15, Winter: $2, Spring: $10/MW-day
  - Exception: Zone 9 (LA/TX) with $59 in Fall and $19 in Winter (required higher priced supply within the zone to meet its Local Clearing Requirement).
- Actions taken by Market Participants such as delaying retirements and making additional existing capacity available to the region, resulted in adequate capacity.
- Many of these actions may not be repeatable and the residual capacity and resulting prices do not reflect the risks posed by the portfolio transition.
- MISO's response to the Reliability Imperative reinforces need for urgent reforms to MISO's resource adequacy construct and market design.

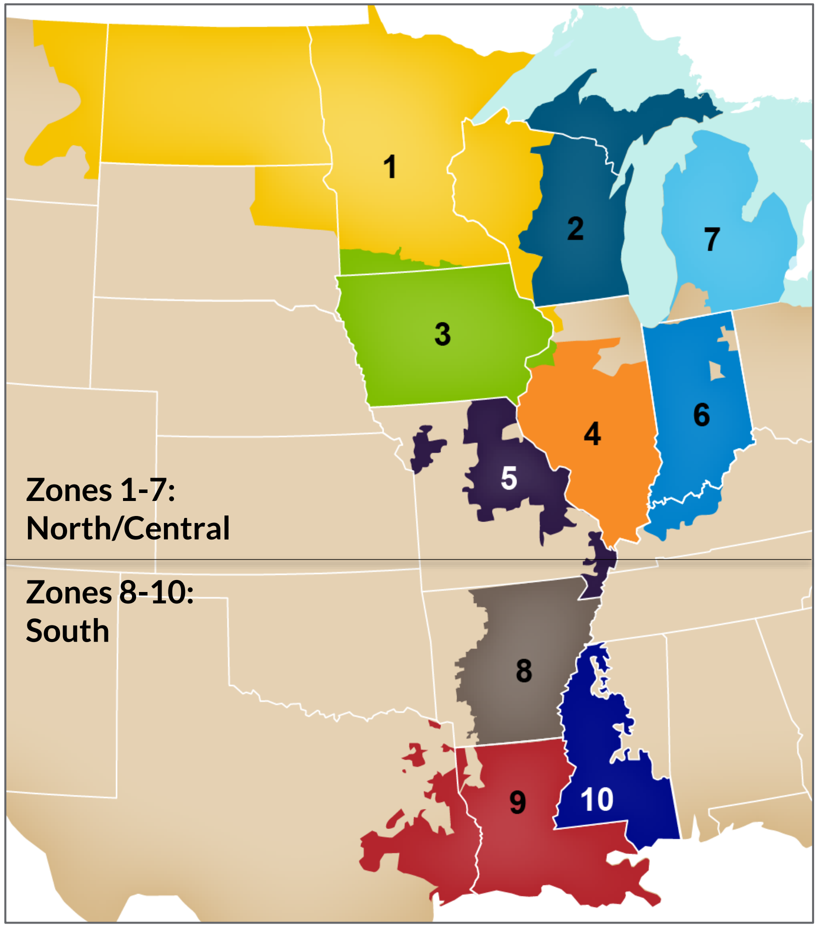
PRA: Planning Resource Auction

2023 PRA demonstrated sufficient capacity at regional, sub-regional and zonal level to meet PRMRs and LCRs

2023 PRA Results

Zone	Local Balancing Authorities	Price $/MW-Day			
		Summer	Fall	Winter	Spring
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$10.00	$15.00	$2.00	$10.00
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$10.00	$15.00	$2.00	$10.00
3	ALTW, MEC, MPW	$10.00	$15.00	$2.00	$10.00
4	AMIL, CWLP, SIPC, GLH	$10.00	$15.00	$2.00	$10.00
5	AMMO, CWLD	$10.00	$15.00	$2.00	$10.00
6	BREC, CIN, HE, IPL, NIPS, SIGE	$10.00	$15.00	$2.00	$10.00
7	CONS, DECO	$10.00	$15.00	$2.00	$10.00
8	EAI	$10.00	$15.00	$2.00	$10.00
9	CLEC, EES, LAFA, LAGN, LEPA	$10.00	$59.21	$18.88	$10.00
10	EMBA, SME	$10.00	$15.00	$2.00	$10.00
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	$10.00	$15.00	$2.00	$10.00

MISO Resource Adequacy Zones



PRMR: Planning Reserve Margin Requirement

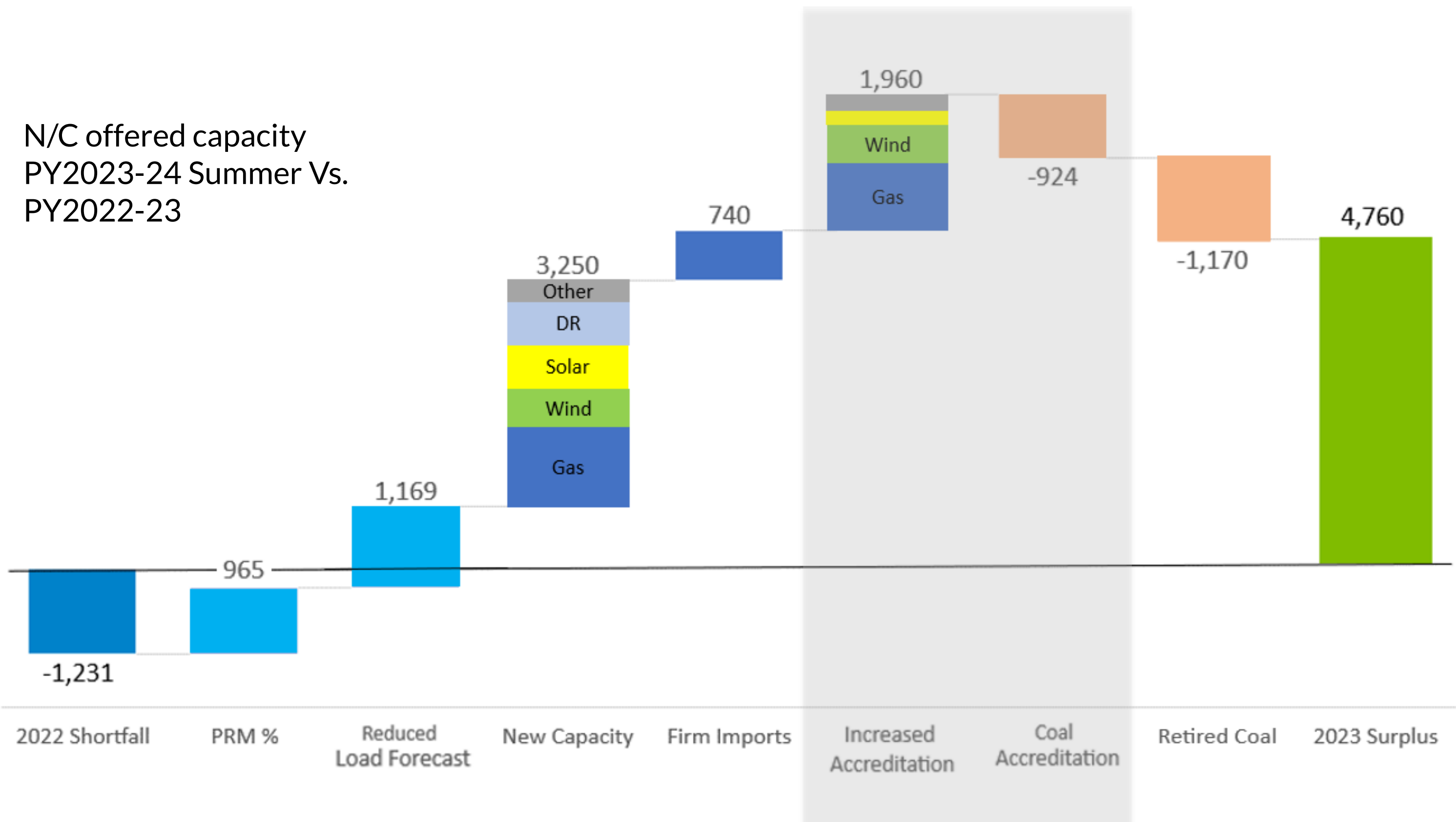
LCR: Local Clearing Requirements

ERZ: External Resource Zone

 Highlighted prices show price separation for the zone/season.

North/Central region demonstrated adequate supply driven by a combination of lower demand, new generation, delayed retirements, additional imports and higher accreditation

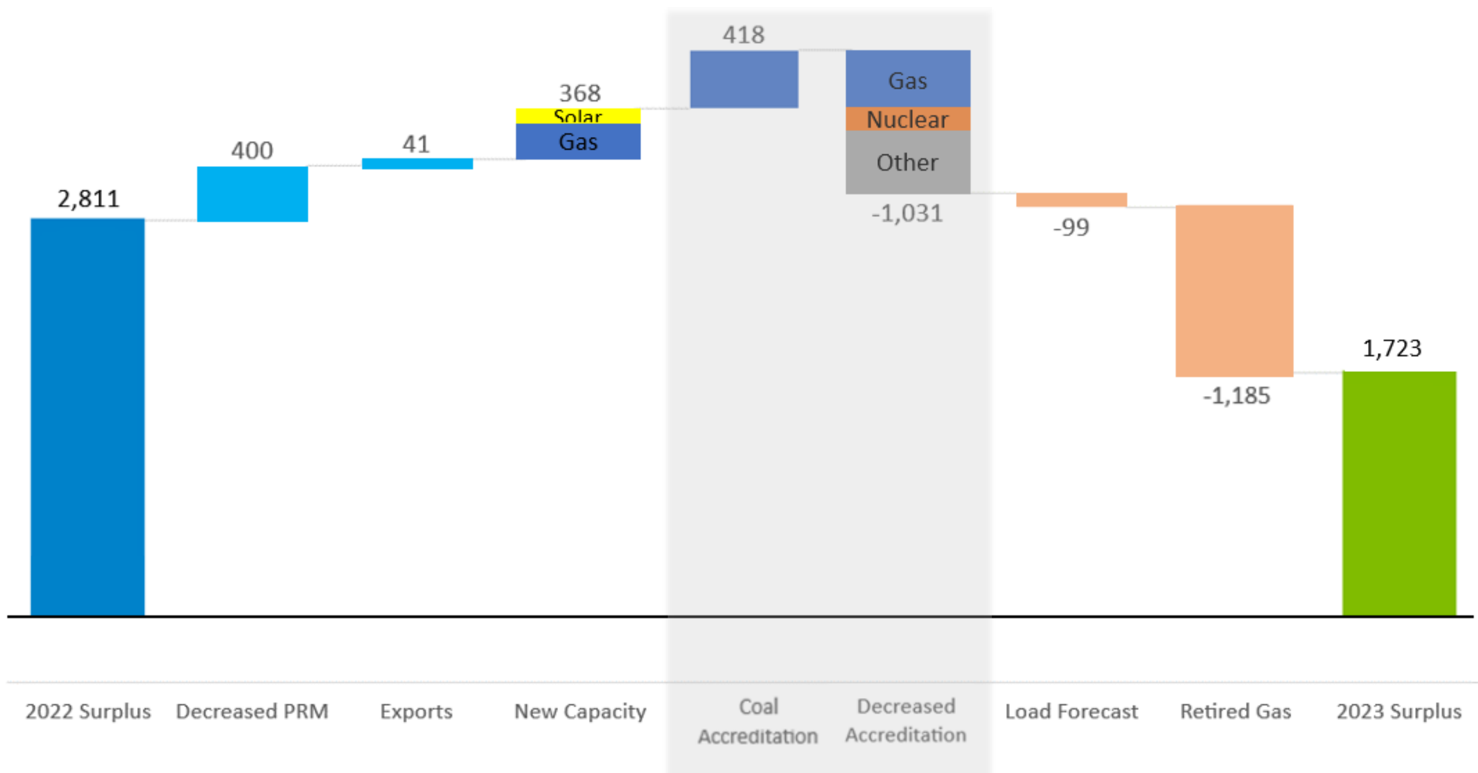
Capacity offered in N/C exceeds requirements by 4,760 MW (4.7%)



Capacity indicated is all accredited values.

South region continues to remain adequate in PY 2023-24 however offered capacity shows decline driven largely by retirements.

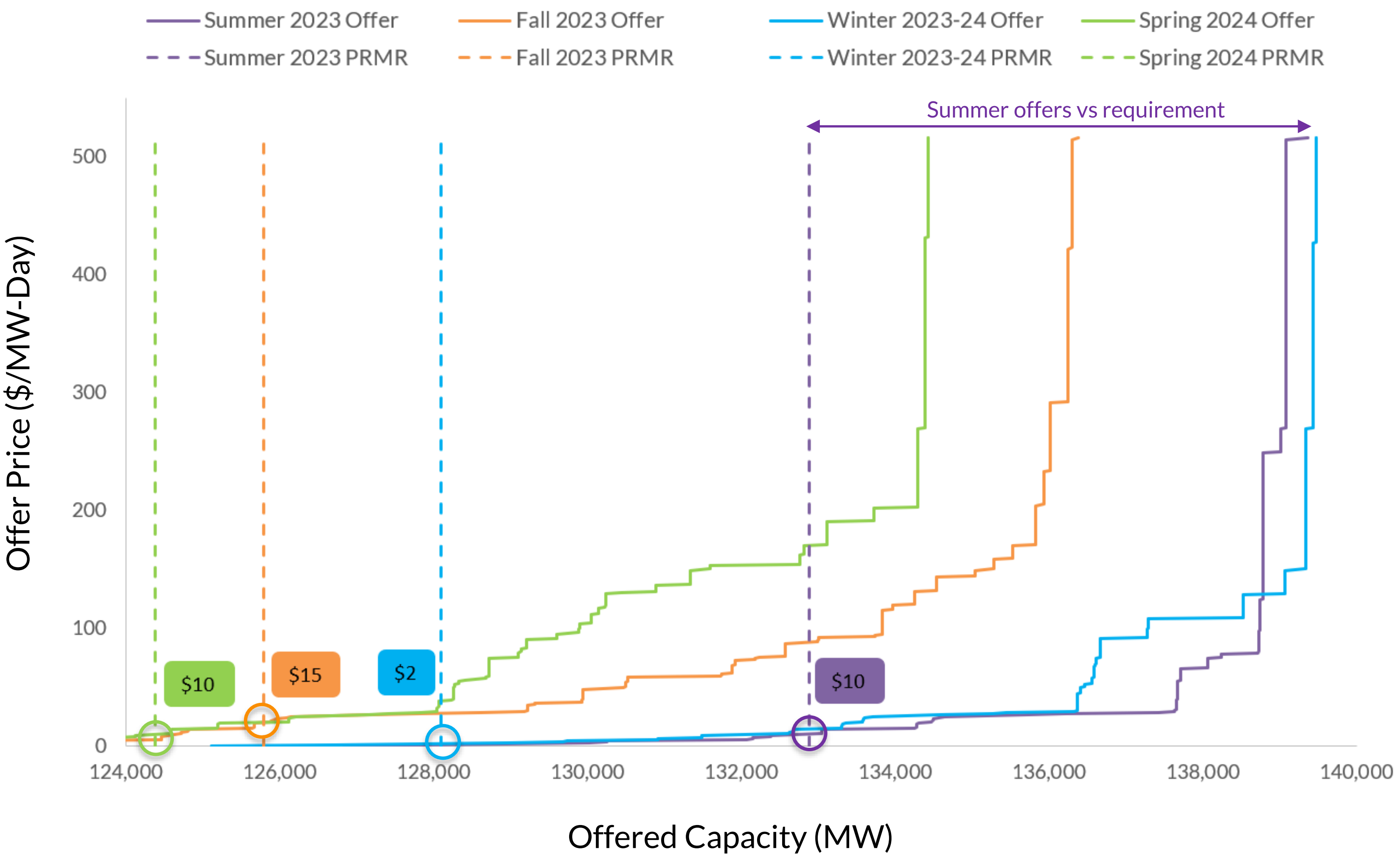
Capacity offered in South exceeds requirements by 1,723 MW (5.1%)



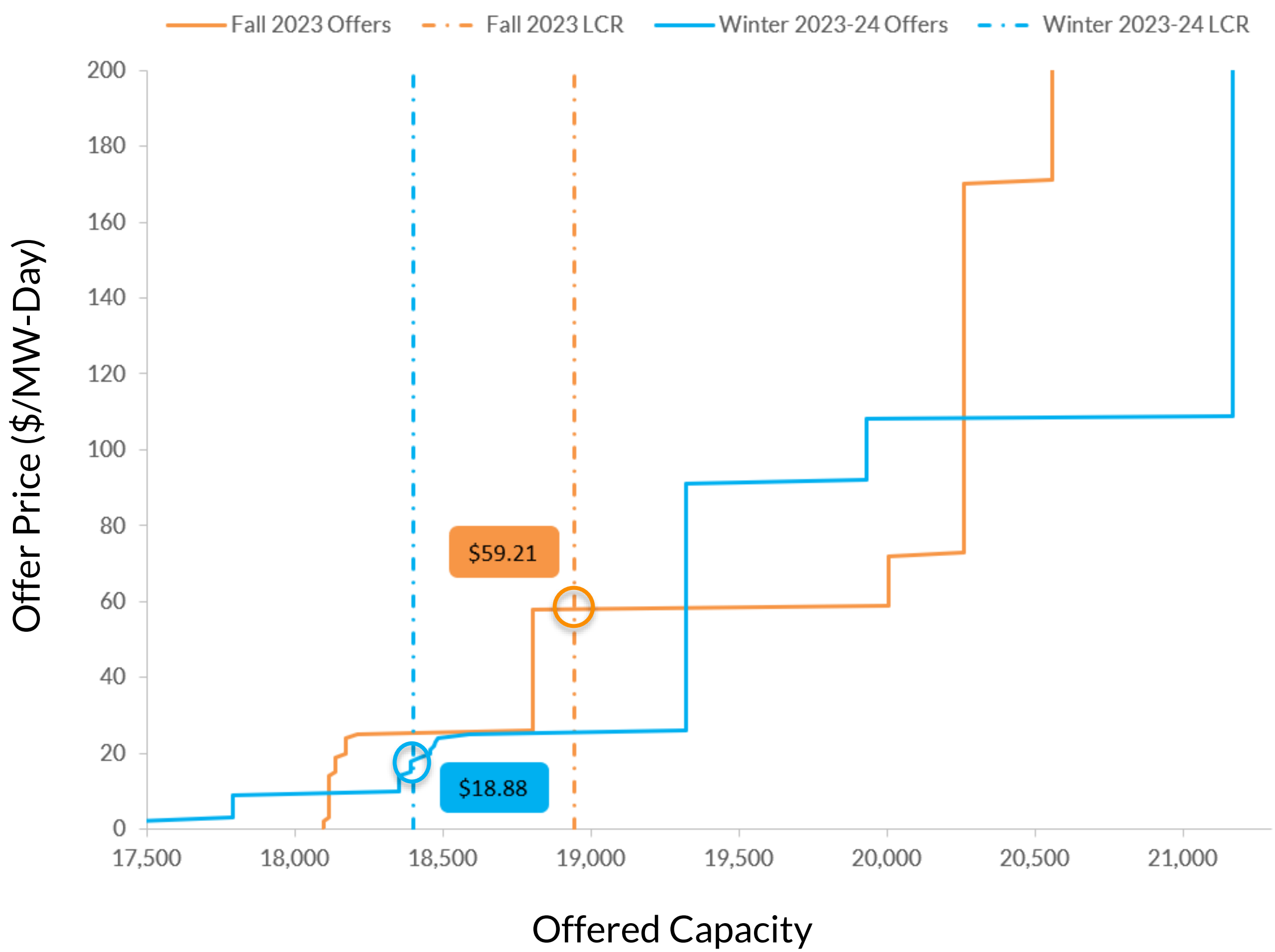
South offered capacity PY2023-24 Summer Vs. PY2022-23

Capacity indicated is all accredited values.

Adequate supply resulted in flat auction clearing prices across the footprint for all seasons, with the exception of Zone 9



In Fall and Winter, LRZ9 required higher priced supply within the zone to meet its local clearing requirement

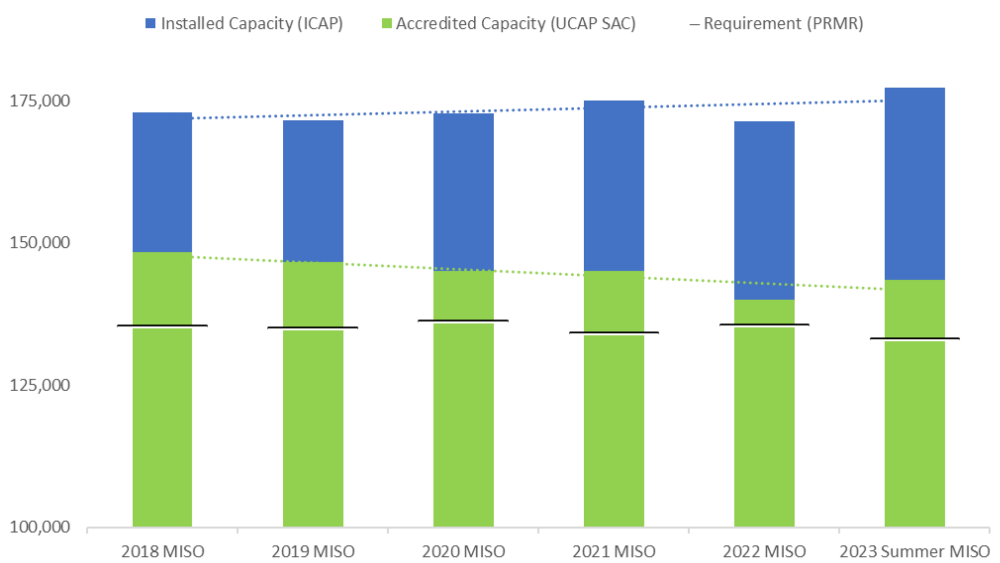


Note: Generation used to meet the Summer and Spring LCR was priced at or lower than MISO South region Auction Clearing Price.

Chart with all seasons included in appendix on slide 36.

Adequate supply this summer and the resulting prices do not reflect the continued risks posed by the portfolio transition

- Impacts of the seasonal construct such as reduced summer PRM and seasonal accounting of retirements contributed to the surplus capacity.
- Reduced load forecasts and actions taken by members such as delayed retirements and increased imports may not be repeatable.
- Historic trends and projections based on member-announced plans* show a continued decline in accredited capacity even as installed capacity increases.



Urgent reforms to MISO's resource adequacy and market design are necessary to ensure continued reliability.

PRM: Planning Reserve Margin

[* From 2022 Regional Resource Assessment Survey Results]

MISO's workplan includes the work needed to evolve our plans and processes to meet the Reliability Imperative

Issue	Challenges	Mitigation
Fleet Change	Declining accredited capacity, declining reserve margins, and changing risk profile	• Continue developing attributes criteria and improved accreditation for resources
Reliability Planning	Reliability is not a yes/no criteria, it's a continuum that considers numerous factors and range or risk tolerance	• Update loss-of-load assessments • Develop Reliability Based Demand Curve • Ensure alignment of market and reliability procedures during extreme events
Forecasting	Load and intermittent generation forecasting needs to be more accurate	• Improve forecasting data and methods, including uncertainty forecasting. • Enhance control room automation
Intraregional and Interregional Support	Increased reliance on geographic scope Increased reliance on gas industry performance during critical events	• Continue developing transmission (JTIQ and LRTP Tranche 2) • Improved agreements with neighbors for emergency scenarios • Improve gas/electric coordination

Next Steps

- **May 19** – Conference call presentation of PRA results
- **May 23**
  - Zonal Deliverability Benefits presented at the May RASC
  - MISO publishes cleared LMRs to Operations tools
- **June 1** – New Planning Year starts
- **June 19** – Posting of PRA masked offer data per Module E 69.A.7.4

https://help.misoenergy.org/support/

Appendix

Table of Contents – page 1/2

Table of Contents – page 2/2

Acronyms

ACP: Auction Clearing Price
ARC: Aggregator of Retail Customers
BTMG: Behind the Meter Generator
CIL: Capacity Import Limit
CEL: Capacity Export Limit
CONE: Cost of New Entry
DR: Demand Resource
EE: Energy Efficiency
ER: External Resource
ERZ: External Resource Zones
FRAP: Fixed Resource Adequacy Plan
ICAP: Installed Capacity
IMM: Independent Market Monitor
LCR: Local Clearing Requirement
LMR: Load Modifying Resource
LRZ: Local Resource Zone
LSE: Load Serving Entity
PRA: Planning Resource Auction
PRM: Planning Reserve Margin
PRMR: Planning Reserve Margin Requirement
RASC: Resource Adequacy Sub-Committee
SAC: Seasonal Accredited Capacity
SS: Self Schedule
SFT: Simultaneous Feasibility Test
UCAP: Unforced Capacity
ZIA: Zonal Import Ability
ZRC: Zonal Resource Credit

Summer 2023 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,234.4	13,371.2	10,491.9	9,559.5	8,115.3	18,107.7	21,232.8	7,915.8	21,234.3	4,628.3	N/A	132,891.2
Offer Submitted (Including FRAP)	21,293.8	14,191.9	11,323.8	8,482.5	7,392.0	15,473.9	21,730.0	11,083.2	21,198.7	4,755.5	2,448.6	139,373.9
FRAP	14,042.9	11,237.4	4,245.7	537.4	0.0	949.7	1,457.5	535.2	166.2	1,315.6	309.1	34,796.7
Self Scheduled (SS)	5,302.9	2,431.7	6,557.7	5,673.2	7,372.0	9,940.7	19,918.7	9,777.1	19,359.6	3,071.6	1,569.6	90,974.8
Non-SS Offer Cleared	168.9	443.5	517.4	1,312.0	20.0	3,423.1	4.4	449.4	331.5	321.7	127.8	7,119.7
Committed (Offer Cleared + FRAP)	19,514.7	14,112.6	11,320.8	7,522.6	7,392.0	14,313.5	21,380.6	10,761.7	19,857.3	4,708.9	2,006.5	132,891.2
LCR	15,076.1	10,552.0	6,806.3	2,935.0	6,529.5	11,567.6	18,785.5	7,134.5	18,931.4	3,690.0	-	N/A
CIL	5,301	3,477	6,108	7,884	3,576	8,492	5,087	4,139	5,268	3,064	-	N/A
ZIA	5,299	3,477	6,043	6,992	3,576	8,092	5,087	4,091	4,456	3,064	-	N/A
Import	0.0	0.0	0.0	2,036.9	723.3	3,794.2	0.0	0.0	1,377.0	0.0	-	7,931.4
CEL	3,959	2,550	4,310	NLF*	NLF*	2,703	3,953	5,503	1,574	1,794	-	N/A
Export	1,280.3	741.4	828.9	0.0	0.0	0.0	147.8	2,845.9	0.0	80.6	2,006.5	7,931.4
ACP ($/MW-Day)	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	N/A

Values displayed in MW UCAP　　**NLF = No Limit Found: Tier 1 & 2 source capacity is less than the study transfer limit*

Fall 2023 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	16,789.4	12,181.8	9,979.6	8,811.7	7,645.6	17,237.2	19,760.9	7,580.1	21,082.1	4,727.0	N/A	125,795.4
Offer Submitted (Including FRAP)	20,783.4	14,173.2	11,628.6	8,303.0	6,793.8	15,298.0	20,849.7	10,546.1	20,848.3	5,087.3	2,070.8	136,382.2
FRAP	12,864.0	10,064.9	3,936.7	428.5	0.0	926.5	1,410.5	469.8	164.4	1,354.3	169.8	31,789.4
Self Scheduled (SS)	4,950.8	2,858.9	6,104.5	5,850.8	6,740.3	9,203.7	18,745.0	8,815.1	17,527.4	3,307.5	1,528.5	85,632.5
Non-SS Offer Cleared	691.0	580.0	689.7	1,211.5	0.0	3,160.7	4.5	157.9	1,250.9	370.6	256.7	8,373.5
Committed (Offer Cleared + FRAP)	18,505.8	13,503.8	10,730.9	7,490.8	6,740.3	13,290.9	20,160.0	9,442.8	18,942.7	5,032.4	1,955.0	125,795.4
LCR	13,064.2	8,764.3	0.0	4,552.3	4,358.7	13,290.9	20,059.0	5,608.2	18,942.7	4,307.8	-	N/A
CIL	6,528	4,411	14,375	5,173	5,380	6,070	4,285	4,705	6,045	2,425	-	N/A
ZIA	6,526	4,411	14,310	4,281	5,380	5,670	4,285	4,657	5,233	2,425	-	N/A
Import	0.0	0.0	0.0	1,320.9	905.3	3,946.3	0.0	0.0	2,139.4	0.0	-	8,311.9
CEL	3,804	3,577	4,354	NLF*	1,992	1,701	3,990	5,080	1,526	2,878	-	N/A
Export	1,716.4	1,322.0	751.3	0.0	0.0	0.0	399.1	1,862.7	0.0	305.4	1,955.0	8,311.9
ACP ($/MW-Day)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	59.21	15.00	15.00	N/A

Values displayed in MW UCAP   **NLF = No Limit Found: Tier 1 & 2 source capacity is less than the study transfer limit*

Winter2023/24 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,245.5	11,708.9	10,215.4	9,093.9	8,231.1	18,290.9	16,927.7	8,518.6	22,110.4	4,761.8	N/A	128,104.2
Offer Submitted (Including FRAP)	22,178.0	13,934.4	13,349.6	7,738.9	6,906.5	14,999.3	21,569.9	10,042.5	21,215.3	5,058.7	2,489.4	139,482.5
FRAP	13,361.7	9,638.1	4,464.0	459.1	0.0	854.0	1,316.7	396.9	149.3	1,788.9	299.5	32,728.2
Self Scheduled (SS)	7,639.4	2,649.7	6,626.9	6,286.2	6,906.5	10,182.7	19,356.0	9,642.9	17,283.8	3,145.6	1,817.7	91,537.4
Non-SS Offer Cleared	64.7	1,024.6	379.3	645.2	0.0	710.3	4.3	0.0	965.0	29.1	16.1	3,838.6
Committed (Offer Cleared + FRAP)	21,065.8	13,312.4	11,470.2	7,390.5	6,906.5	11,747.0	20,677.0	10,039.8	18,398.1	4,963.6	2,133.3	128,104.2
LCR	15,797.1	8,596.5	3,628.8	6,009.0	6,022.8	10,854.4	15,693.1	5,691.3	18,398.1	4,519.4	-	N/A
CIL	4,937	4,905	11,039	3,928	3,811	8,818	6,340	4,729	6,080	2,396	-	N/A
ZIA	4,935	4,905	10,974	3,036	3,811	8,418	6,340	4,681	5,268	2,396	-	N/A
Import	0.0	0.0	0.0	1,703.4	1,324.6	6,543.9	0.0	0.0	3,712.3	0.0	-	13,284.2
CEL	3,501	4,198	7,002	NLF*	6,348	1,242	4,350	5,351	877	1,980	-	N/A
Export	2,820.3	1,603.5	1,254.8	0.0	0.0	0.0	3,749.3	1,521.2	0.0	201.8	2,133.3	13,284.2
ACP ($/MW-Day)	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	18.66	2.00	2.00	N/A

Values displayed in MW UCAP

**NLF = No Limit Found: Tier 1 & 2 source capacity is less than the study transfer limit*

Spring 2024 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	17,304.2	12,009.8	9,590.0	8,033.5	7,392.2	17,552.4	19,038.9	7,678.5	21,272.9	4,516.7	N/A	124,389.1
Offer Submitted (Including FRAP)	19,822.1	14,216.1	11,399.5	8,082.2	7,180.0	14,991.5	19,772.5	10,728.6	20,962.5	4,931.4	2,351.8	134,438.2
FRAP	12,916.5	10,051.5	3,934.4	411.2	0.0	892.0	1,320.2	362.7	151.0	1,388.7	307.4	31,735.6
Self Scheduled (SS)	5,624.3	2,842.2	6,037.4	5,762.5	6,014.5	9,298.6	17,395.3	9,377.4	18,162.1	3,125.0	1,540.1	85,179.4
Non-SS Offer Cleared	54.9	1,031.4	888.5	1,325.8	0.0	2,742.4	104.0	413.7	714.9	79.2	119.3	7,474.1
Committed (Offer Cleared + FRAP)	18,595.7	13,925.1	10,860.3	7,499.5	6,014.5	12,933.0	18,819.5	10,153.8	19,028.0	4,592.9	1,966.8	124,389.1
LCR	13,171.6	8,039.5	5,175.3	3,539.5	5,829.2	10,978.3	15,654.3	5,907.1	18,105.2	4,303.5	-	N/A
CIL	6,185	4,454	7,675	5,906	3,881	8,162	5,559	4,606	6,250	2,144	-	N/A
ZIA	6,183	4,454	7,610	5,014	3,881	7,762	5,559	4,558	5,438	2,144	-	N/A
Import	0.0	0.0	0.0	534.0	1,377.7	4,619.4	219.4	0.0	2,244.9	0.0	-	8,995.4
CEL	4,321	3,679	6,173	NLF*	3,724	2,344	4,413	5,472	2,240	2,720	-	N/A
Export	1,291.5	1,915.3	1,270.3	0.0	0.0	0.0	0.0	2,475.3	0.0	76.2	1,966.8	8,995.4
ACP ($/MW-Day)	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	N/A

Values displayed in MW UCAP

**NLF = No Limit Found: Tier 1 & 2 source capacity is less than the study transfer limit*

Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	2021-22	2022-23	Summer 23-24	2021-22	2022-23	Summer 23-24
Generation	125,225	121,506.5	122,375.6	118,884	118,745.0	116,989.7
External Resources	3,914	3,638.9	4,514.6	3,798	3,638.9	4,072.5
Behind the Meter Generation	4,131	4,169.3	4,175.2	4,068	4,169.3	4,129.4
Demand Resources	7,294	7,591.4	8,303.5	7,152	7,541.5	7,694.6
Energy Efficiency	0.0	0.0	5.0	0.0	0.0	5.0
Total	**140,564**	**136,906.1**	**139,373.9**	**133,903**	**134,094.7**	**132,891.2**

2023-2024 Seasonal Supply Offered and Cleared

	Offered (ZRC)				Cleared (ZRC)			
Planning Resource	Summer 2023	Fall 2023	Winter 2023-2024	Spring 2024	Summer 2023	Fall 2023	Winter 2023-2024	Spring 2024
Generation	122,375.6	121,403.5	122,375.6	121,403.5	116,989.7	111,713.8	116,989.7	110,195.8
External Resources	4,514.6	4,095.4	4,514.6	4,095.4	4,072.5	3,979.6	4,072.5	3,409.1
Behind the Meter Generation	4,175.2	3,874.2	4,175.2	3,874.2	4,129.4	3,842.8	4,129.4	4,058.9
Demand Resources	8,303.5	7,004.2	8,303.5	7,004.2	7,694.6	6,254.4	7,694.6	6,720.0
Energy Efficiency	5.0	4.9	5.0	4.9	5.0	4.8	5.0	5.3
Total	**139,373.9**	**136,382.2**	**139,373.9**	**136,382.2**	**132,891.2**	**125,795.4**	**132,891.2**	**124,389.1**

Historical Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-$5.00</td></tr>
<tr><td>2021-2022</td><td colspan="7">$5.00</td><td colspan="3">$0.01</td><td>$2.78-$5.00</td></tr>
<tr><td>2022-2023</td><td colspan="7">$236.66</td><td colspan="3">$2.88</td><td>$2.88-236.66</td></tr>
<tr><td>Summer 2023-2024</td><td colspan="11">$10.00</td></tr>
</table>

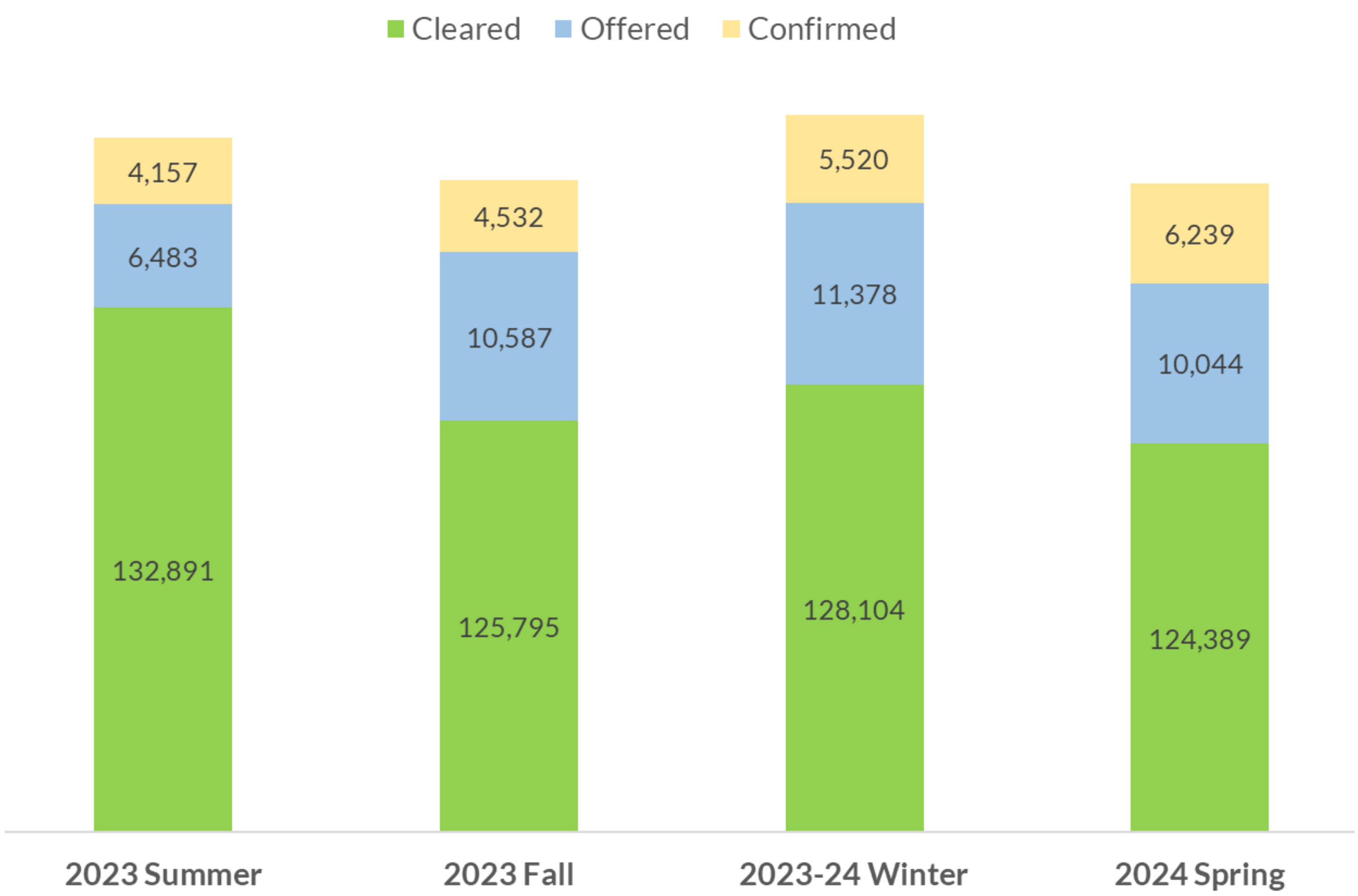
- Auction Clearing Prices shown in $/MW-Day

2023-2024 Seasonal Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>Summer</td><td colspan="11">$10.00</td></tr>
<tr><td>Fall</td><td colspan="8">$15.00</td><td>$59.21</td><td colspan="2">$15.00</td></tr>
<tr><td>Winter</td><td colspan="8">$2.00</td><td>$18.88</td><td colspan="2">$2.00</td></tr>
<tr><td>Spring</td><td colspan="11">$10.00</td></tr>
<tr><td>IMM Conduct Threshold</td><td>28.54</td><td>28.01</td><td>27.01</td><td>28.00</td><td>30.02</td><td>27.01</td><td>29.02</td><td>26.00</td><td>25.78</td><td>25.70</td><td>30.02</td></tr>
<tr><td>Cost of New Entry (Daily)</td><td>285.40</td><td>280.11</td><td>270.11</td><td>280.00</td><td>300.22</td><td>270.11</td><td>290.16</td><td>259.97</td><td>257.75</td><td>257.04</td><td>300.22</td></tr>
<tr><td>Cost of New Entry (Annual)</td><td>104,170</td><td>102,240</td><td>98,590</td><td>102,200</td><td>109,580</td><td>98,590</td><td>105,910</td><td>94,890</td><td>94,080</td><td>93,820</td><td>109,580</td></tr>
</table>

- There was price separation in the Fall and Winter for Zone 9 since it required higher priced supply within the zone to meet its local clearing requirement.
- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Cost of New Entry (CONE)

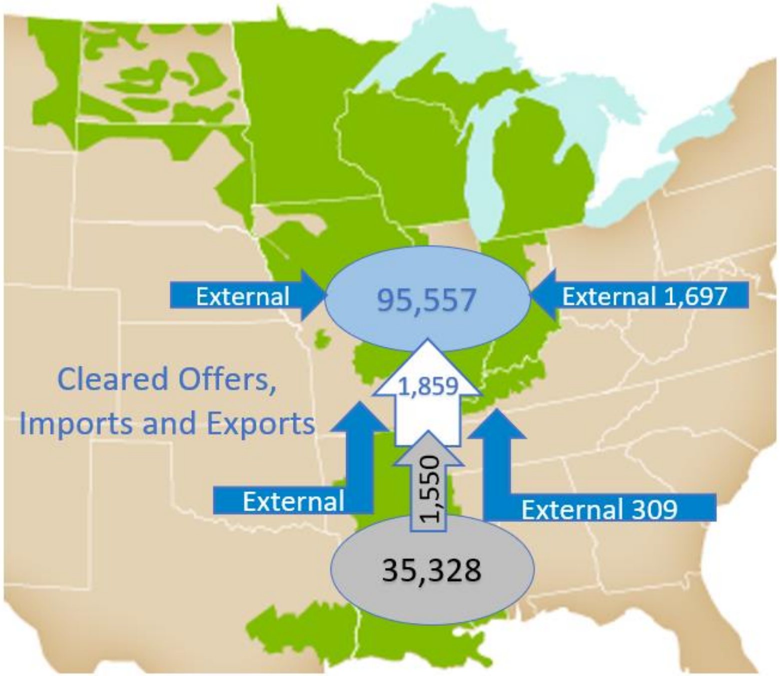
2023-2024 MISO-wide Seasonal Capacity



- Offered and confirmed capacity values are incremental
- PRMR equals cleared capacity
- Surplus is offered capacity in excess of PRMR

Summer 2023 – Offered Capacity & PRMR (MW)

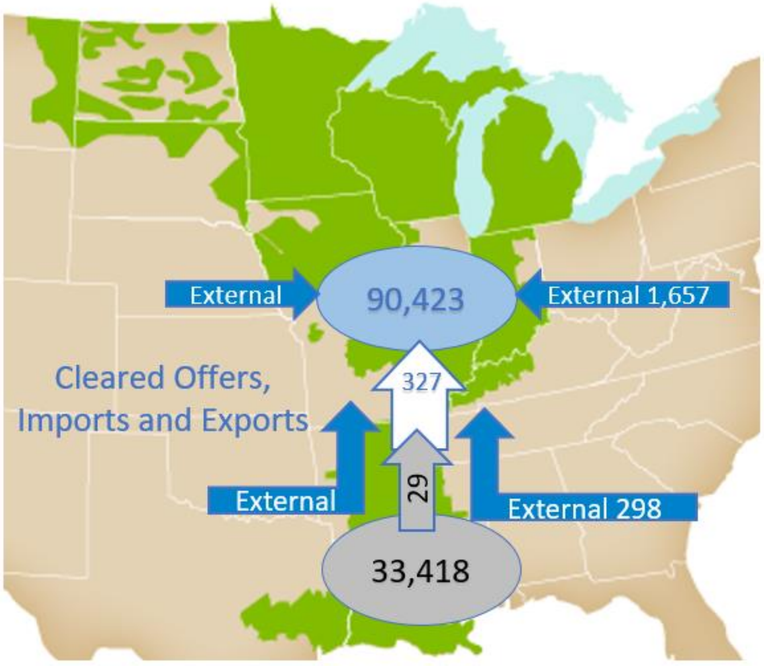
Summer 2023 –Cleared Capacity, Imports & Exports (MW)



Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

Fall 2023 – Offered Capacity & PRMR (MW)

Fall 2023 –Cleared Capacity, Imports & Exports (MW)



Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

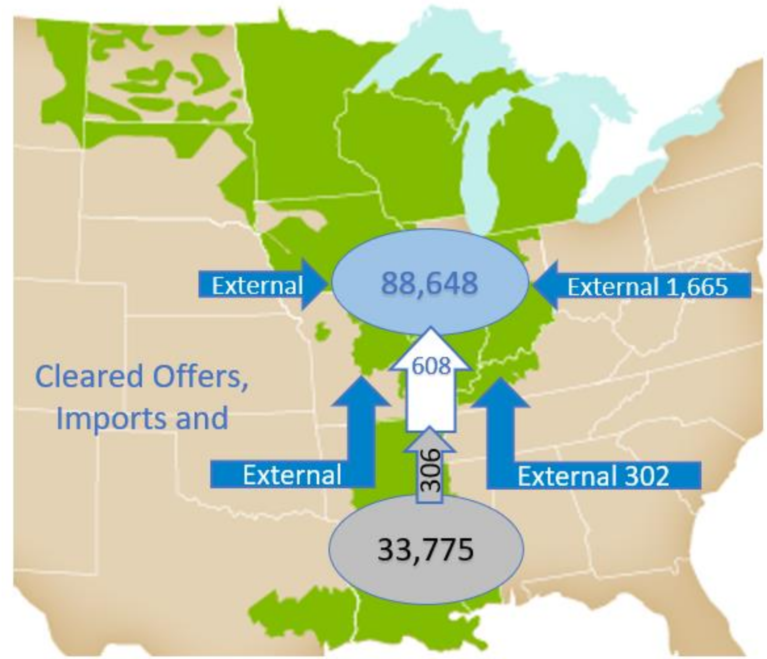
Winter 2023/24 – Offered Capacity & PRMR (MW)

Winter 2023/24 –Cleared Capacity, Imports & Exports (MW)

Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

Spring 2024 – Offered Capacity & PRMR (MW)

Spring 2024 –Cleared Capacity, Imports & Exports (MW)



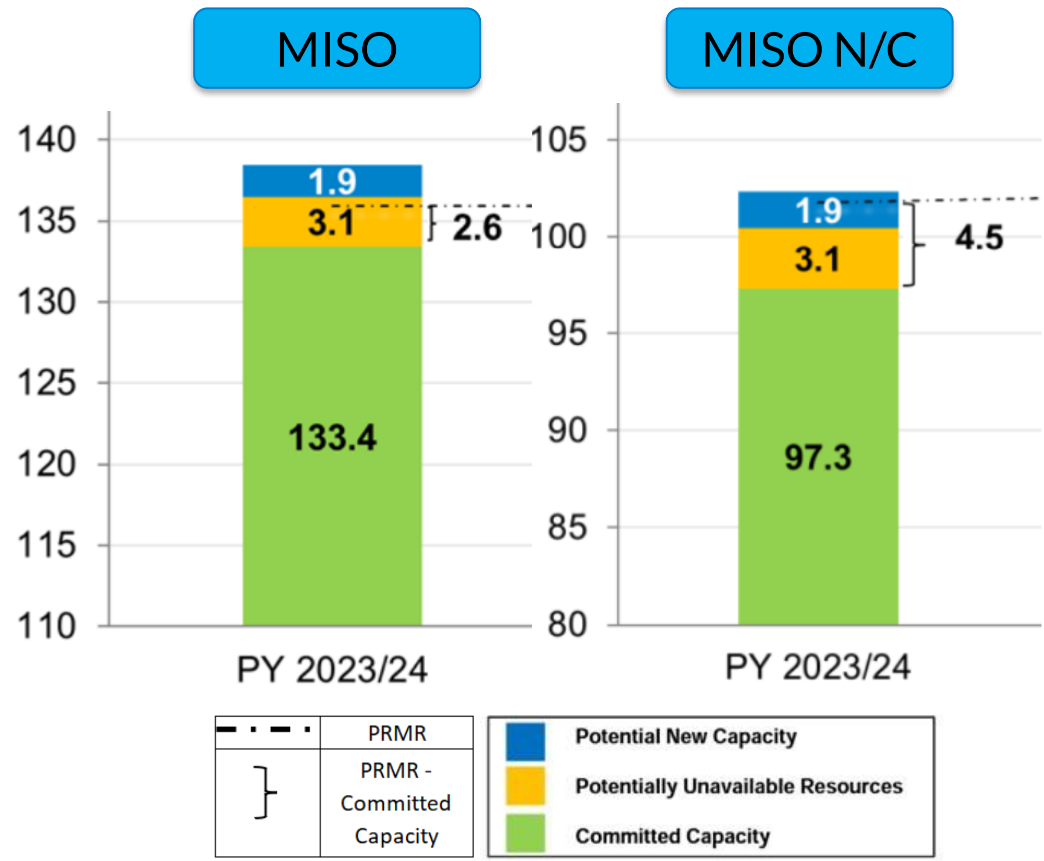
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

MISO

2022 OMS-MISO survey projected deficit in MISO and MISO N/C. Decreased PRMR, participation of potentially unavailable resources, increased imports and accreditation bridged the gap.

2022 OMS-Survey Results vs. Summer 2023 PRA outcomes

- Delayed retirements – 3.54 GW
  - 2.7 of the 3.1GW of Potentially Unavailable Resources offered into the 2023 Summer PRA
  - 443 MW reported as 0 in the 2022 OMS-MISO Survey participated in the 2023 Summer PRA
  - Additionally 400MW of resources participated in the 2023 Summer PRA that did not in 22-23 or the 2022 survey
- 3GW lower PRMR in 2023 Summer PRA vs. Survey comprised of lower PRM% and lower demand forecast
- 700MW new firm imports
- 750MW footprint wide accreditation increase for wind resources



MISO-wide, there was 2.6 GW more of **ZRCs offered** in the Summer 2023 than in 2022. Coal retirements offset by new gas, capacity addition from renewables and LMRs

Offers (GW)	2022	Summer 2023	Change
Gas	58.5	59.9	1.4
Wind	3.8	5.0	1.2
Solar	2.1	3.0	0.9
Water	6.3	6.6	0.3
Nuclear	11.3	11.3	0.0
Coal	40.4	38.9	-1.5
Other Fuels	6.7	6.3	-0.5
DR	7.6	8.3	0.7
Total Offers	**136.8**	**139.4**	**2.6**

Offers (GW)	2022	Summer 2023	Change
Gen	121.5	122.4	0.9
BTMG	4.2	4.2	0.0
ER	3.6	4.5	1.0
DR	7.6	8.3	0.7
Total Offers	**136.8**	**139.4**	**2.6**

There was 3.4 GW more of **Confirmed ICAP** in the Summer 2023 than in 2022. Coal retirements offset by new gas, capacity addition from renewables and LMRs

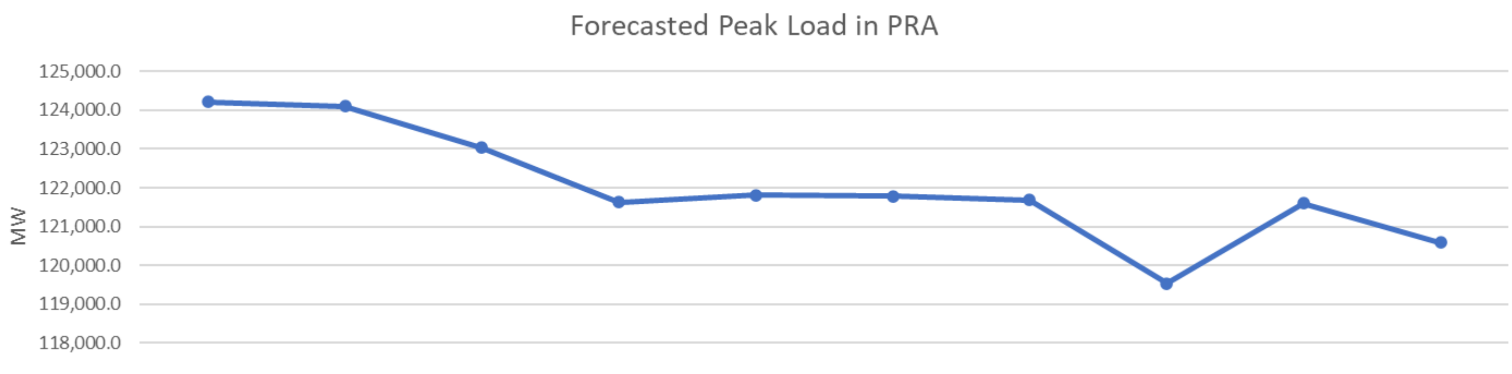
ICAP (GW)	2022	Summer 2023	Change
Gas	64.5	66.3	1.8
Wind	25.8	28.5	2.7
Solar	2.7	4.1	1.4
Water	6.7	6.9	0.2
Nuclear	12.0	12.0	0.0
Coal	47.7	45.4	-2.3
Other Fuels	7.5	7.4	-0.1
DR	7.1	7.5	0.5
Total Offers	**173.9**	**178.1**	**4.3**

ICAP (GW)	2022	Summer 2023	Change
Gen	158.6	161.2	2.6
BTMG	4.5	4.6	0.1
ER	3.7	4.7	1.1
DR	7.1	7.5	0.5
Total Offers	**173.9**	**178.1**	**4.3**

Coal retirements offset by new gas, surplus created with renewables and LMRs

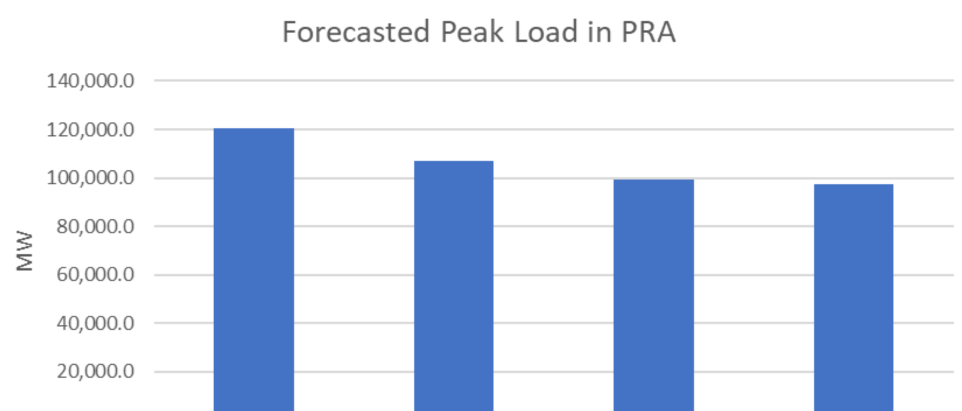
Forecasted Peak Load (CPF)

Year over year the summer CPF (-1.0 GW), PRM (-1.3%) and PRMR (2.44 GW) are lower.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023
Zone(s)	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8

2023-2024 Seasonal Forecasted Peak



	Summer 2023	Fall 2023	Winter 2023-24	Spring 2024
Series1	120,586.8	106,973.8	99,188.0	97,537.6

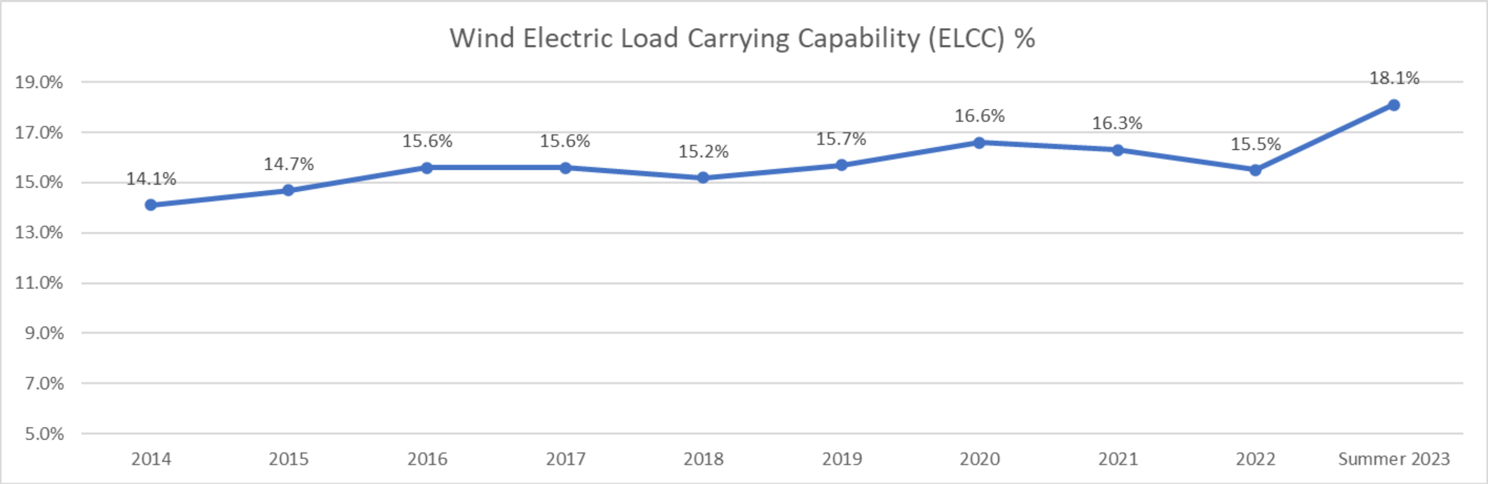
Planning Reserve Margin (%)

Historic PRM Trend

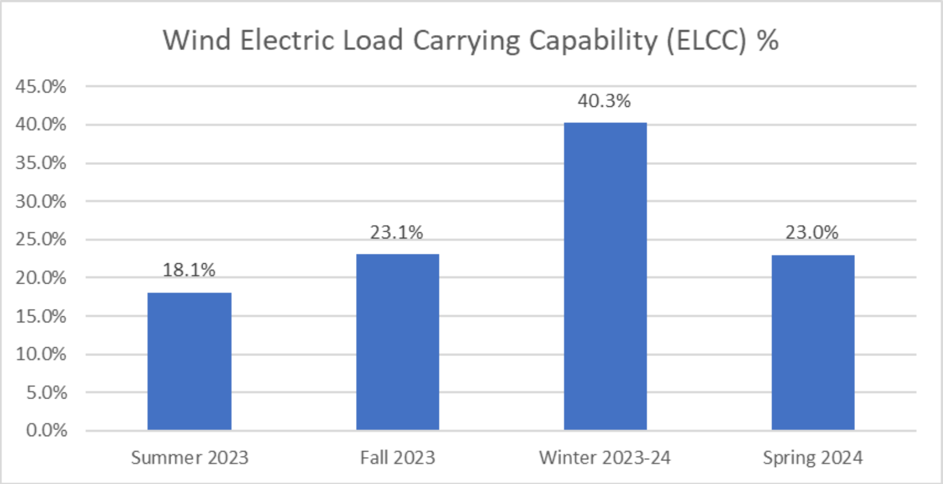
2023-2024 Seasonal PRM

Wind Effective Load Carrying Capacity (%)

Historic ELCC Trend

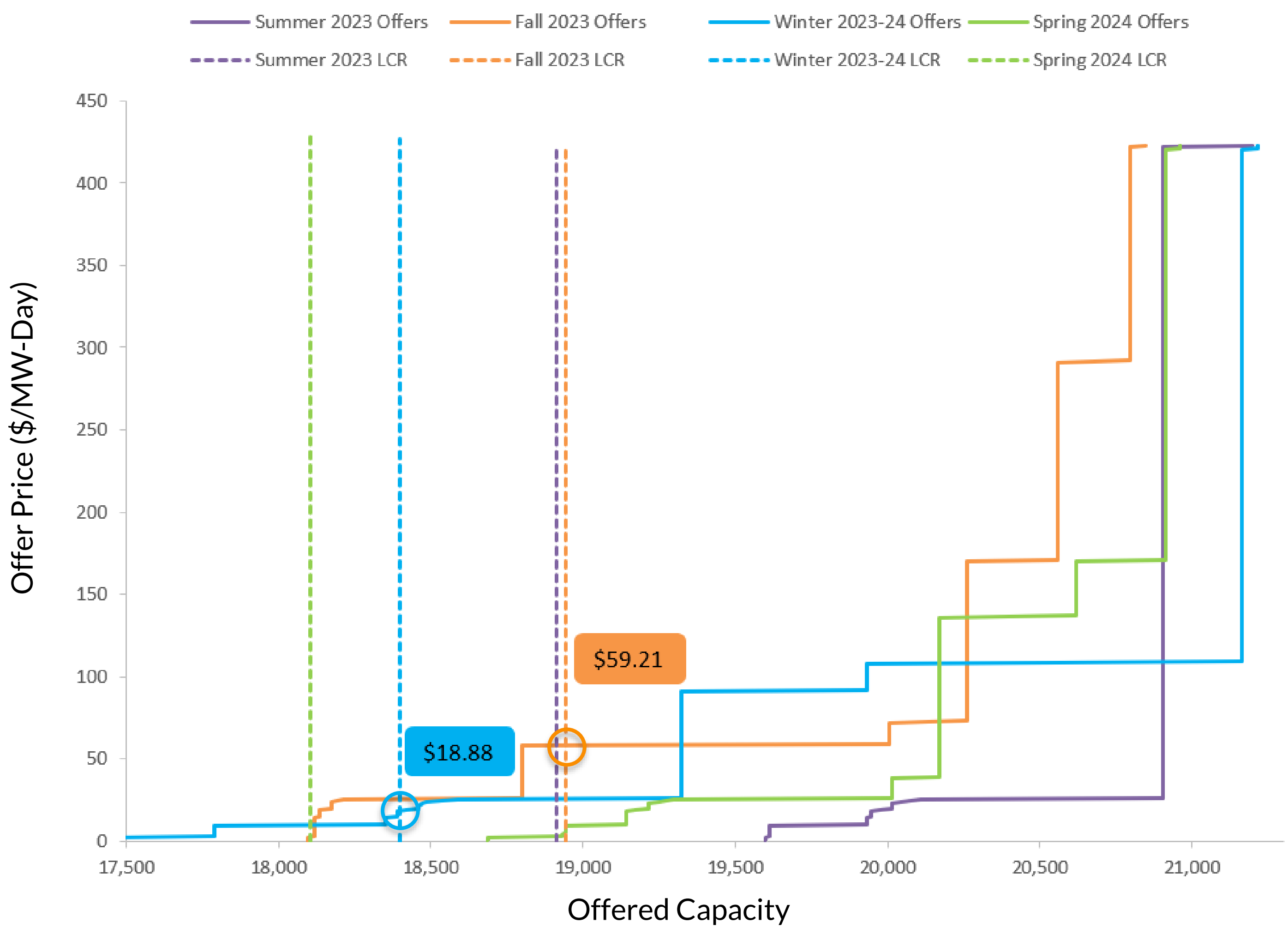


2023-24 ELCC Seasonal

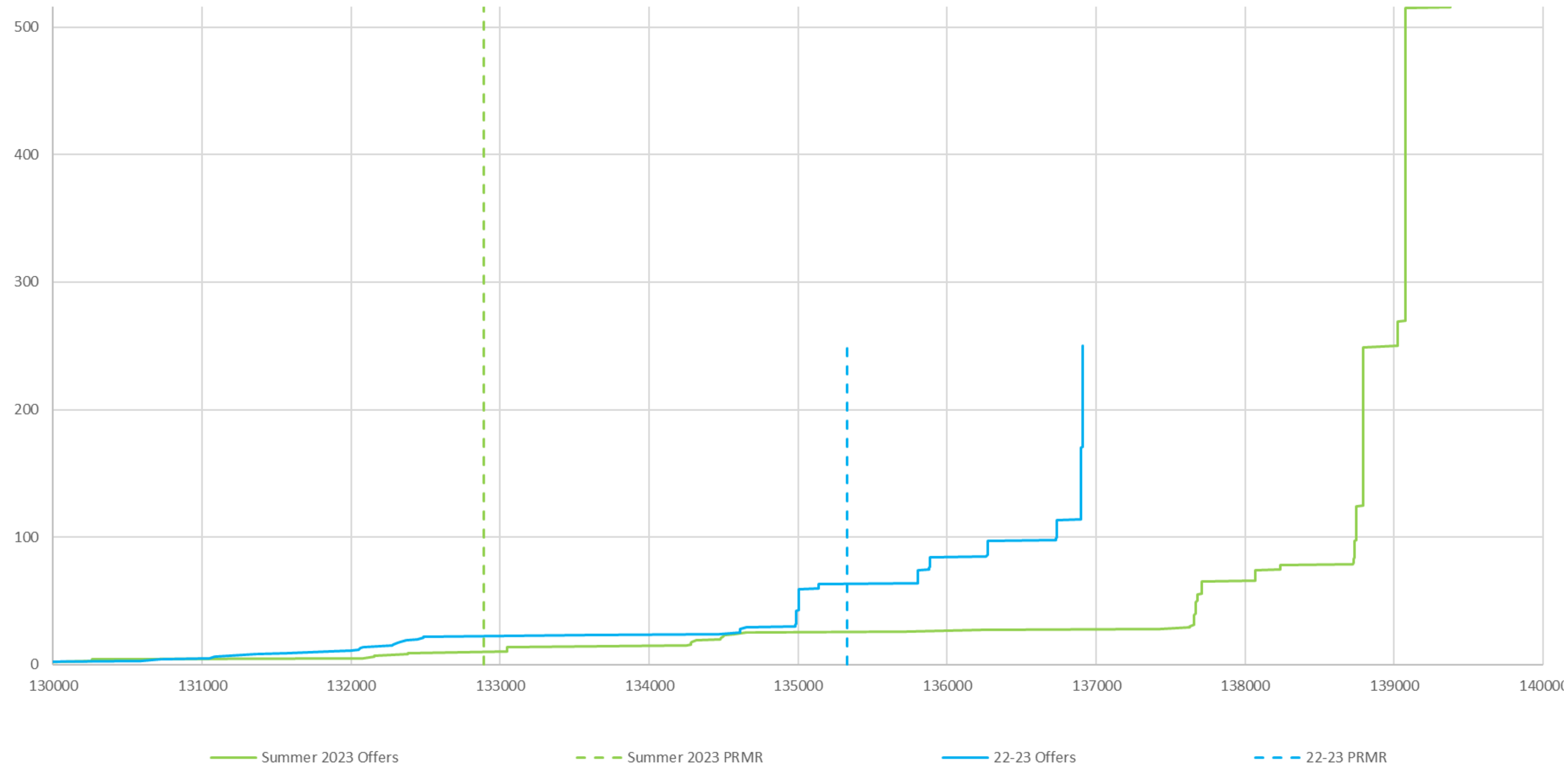


- No change to wind or solar accreditation methodology from previous years
- Methodology applied on a seasonal basis
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar
    - Summer, Fall, Spring 50%
    - Winter 5%

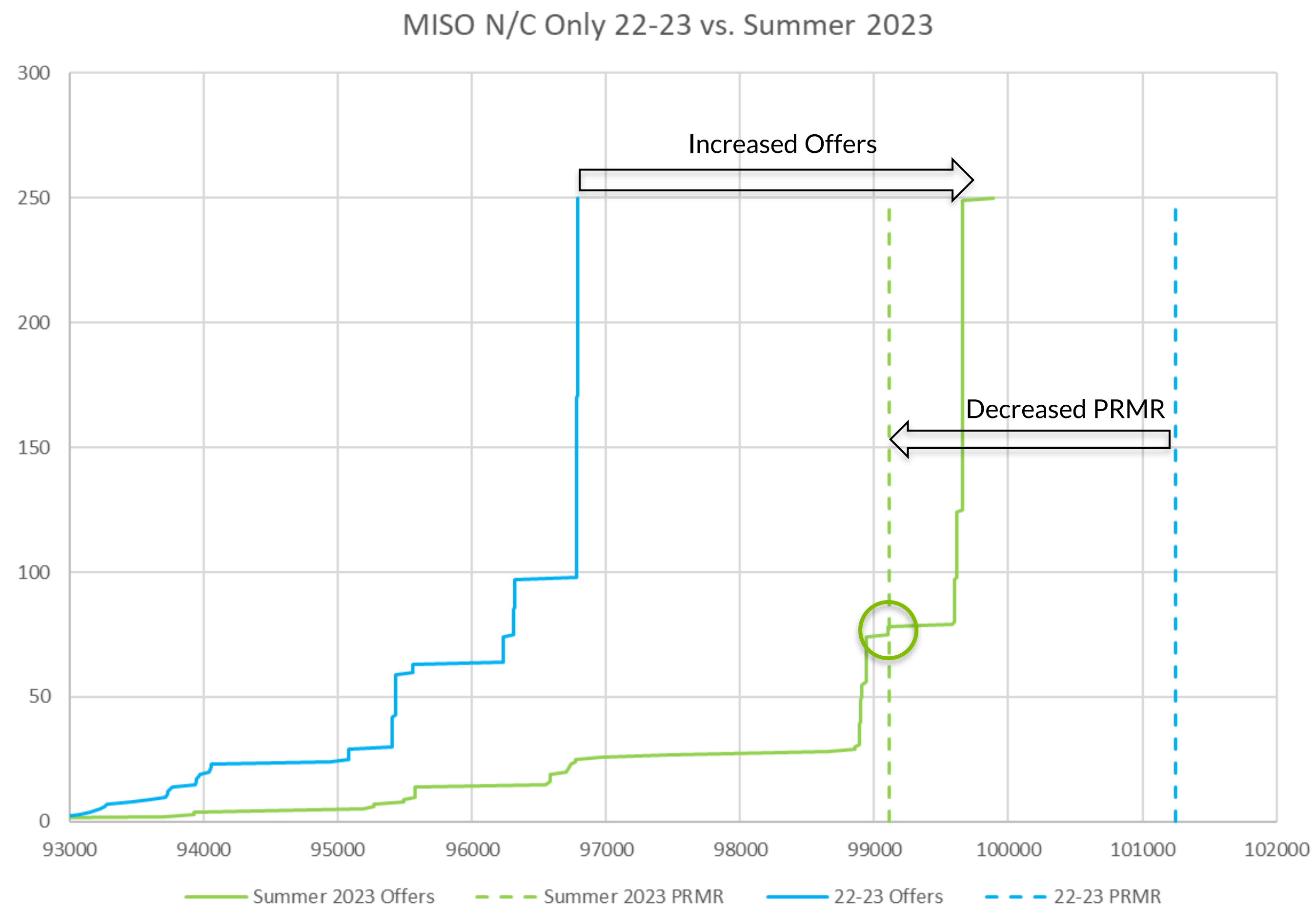
LRZ9 seasonal offer curves and local clearing requirements



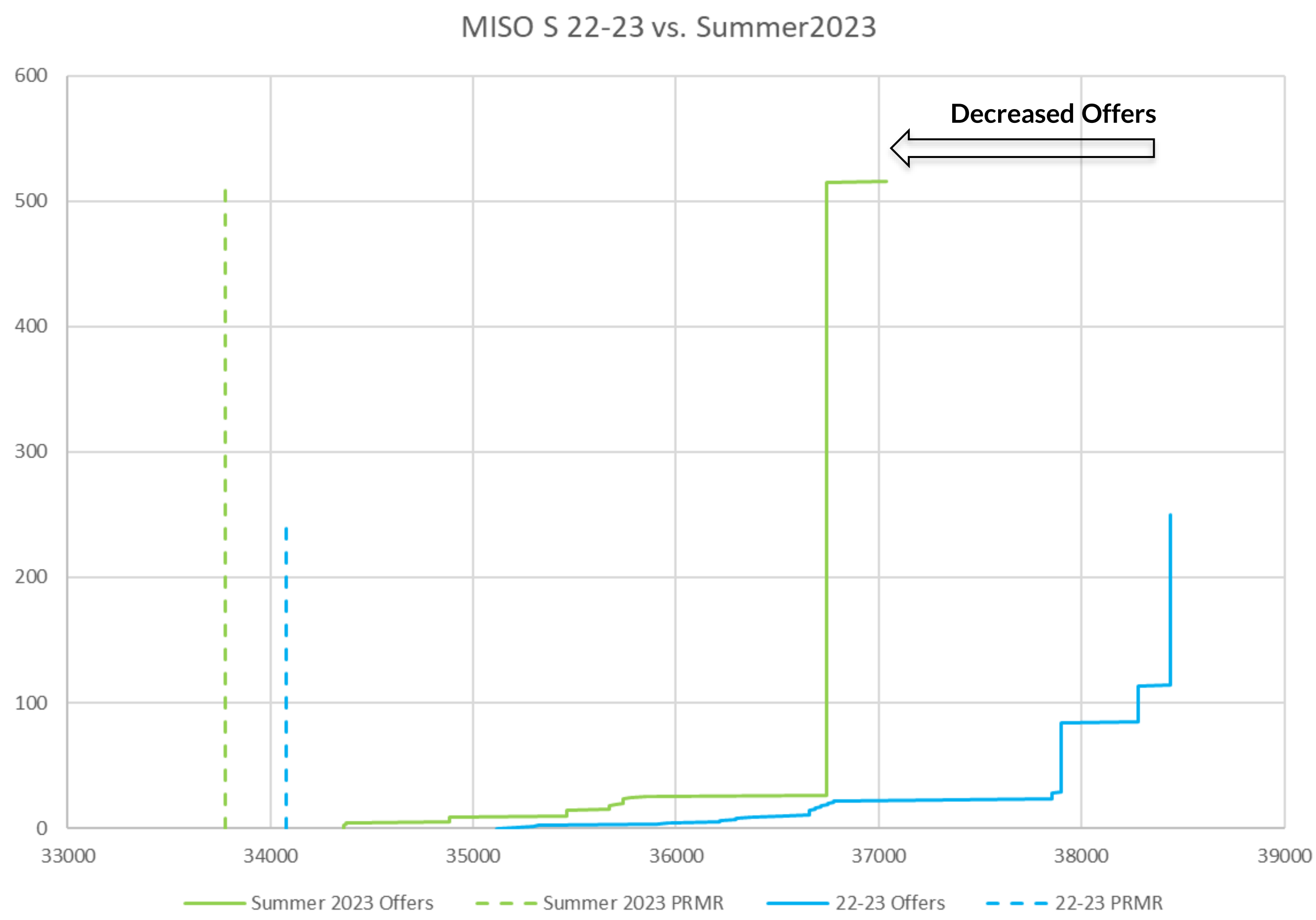
MISO PRMR and Supply curves Summer 2023 vs. 2022-23PY



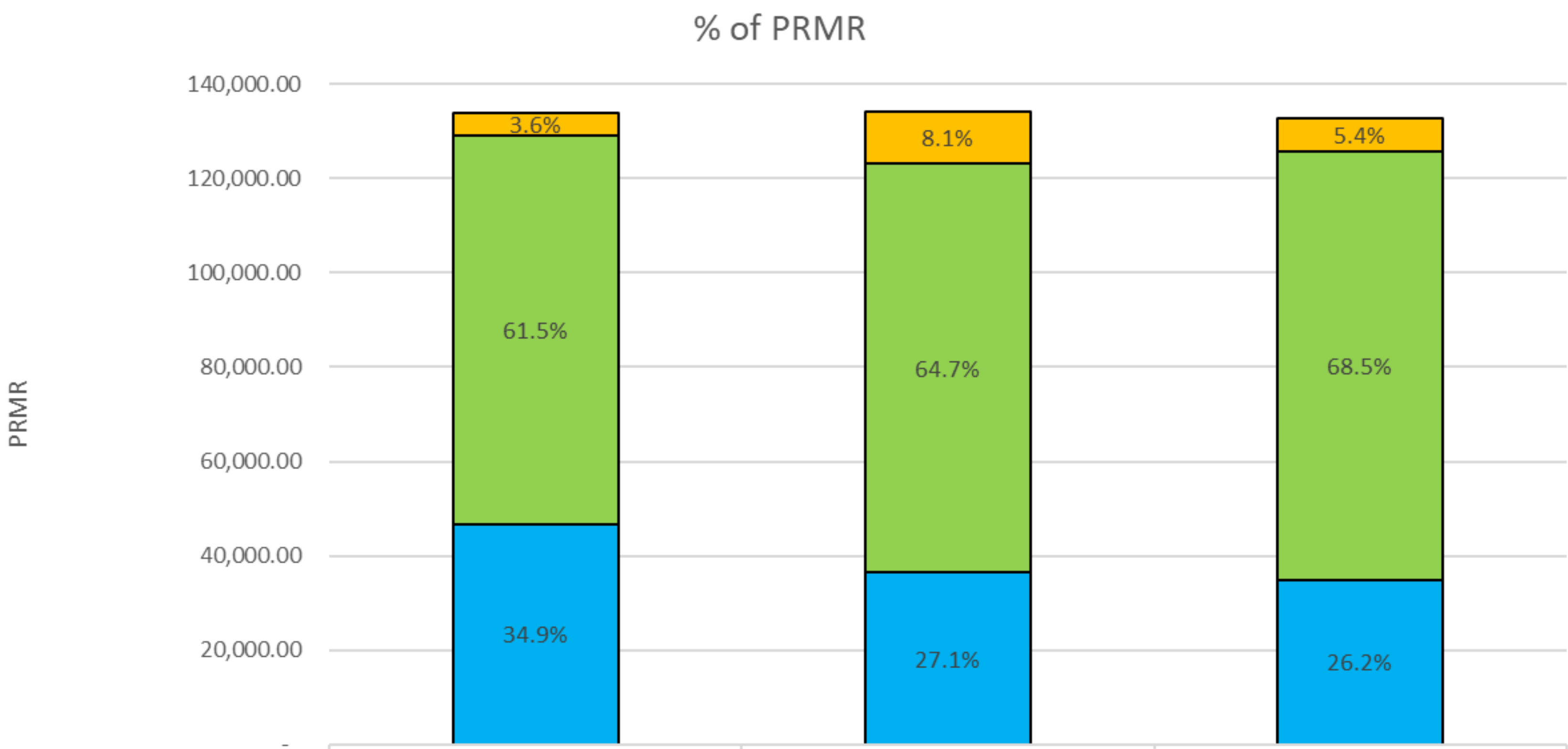
North/Central had sufficient capacity to meet PRMR ($79) without imports unlike PY 22-23 but utilized cheaper imports from MISO South and Externals



MISO South has capacity beyond the region's PRMR and exported to N/C but the offered capacity has decreased since last year

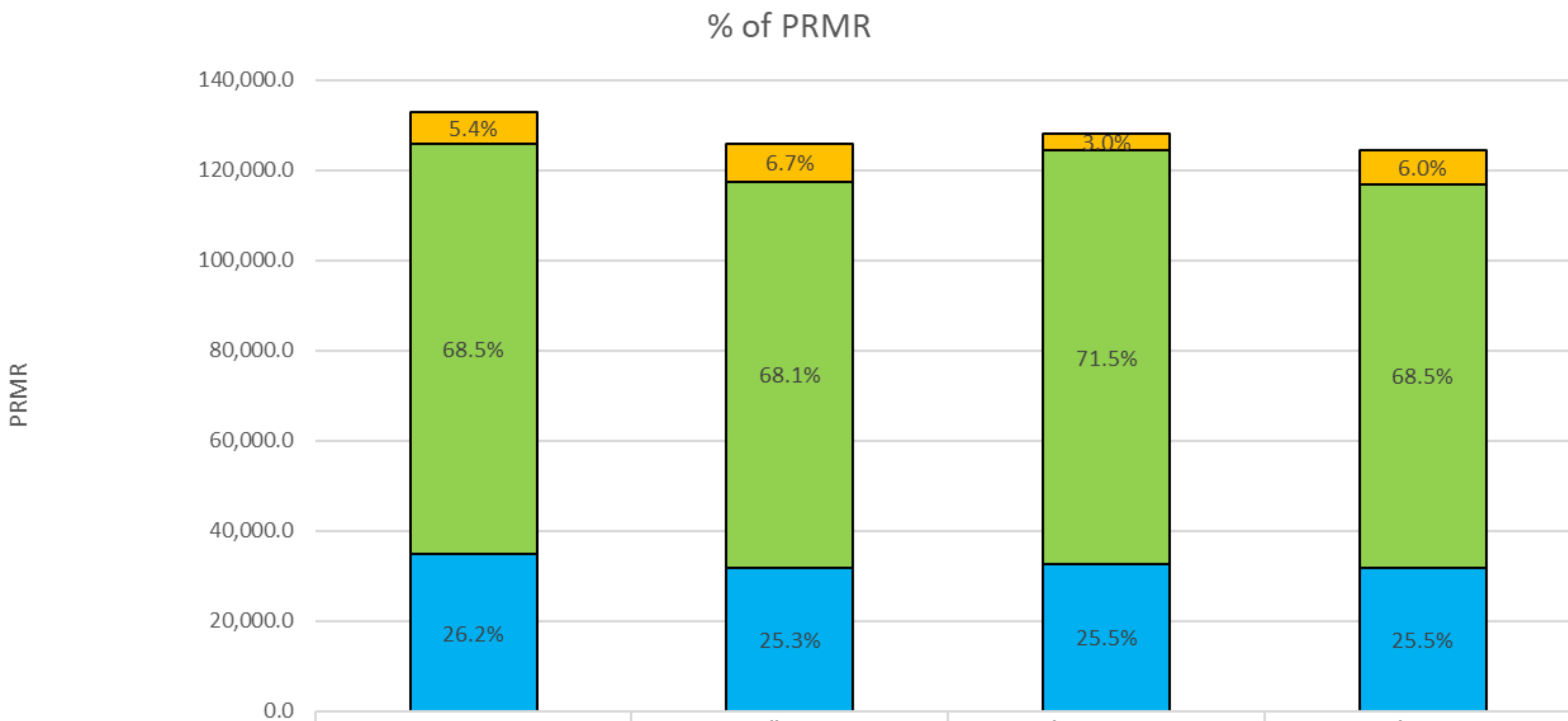


Most members continue to meet resource adequacy requirements through fixed plans and self-scheduling



	2021-22	2022-23	Summer 2023
Cleared Non-Self Scheduled	4,858.42	10,920.10	7,119.7
Self Scheduled	82,286.90	86,784.10	90,974.8
FRAP	46,757.40	36,391.80	34,796.7

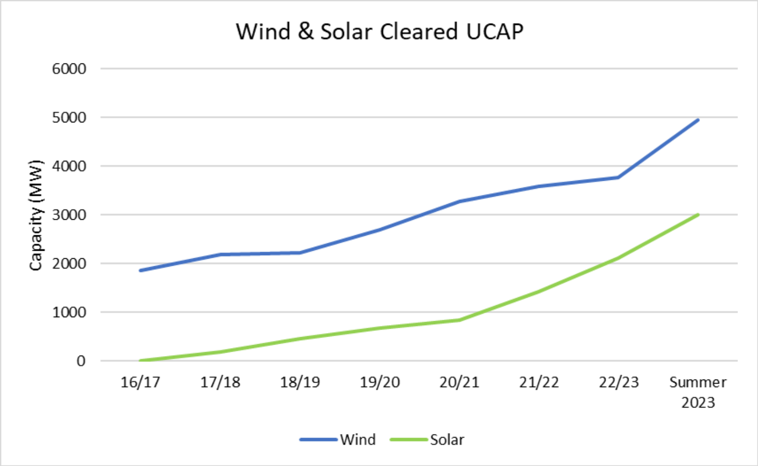
2023-2024 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons

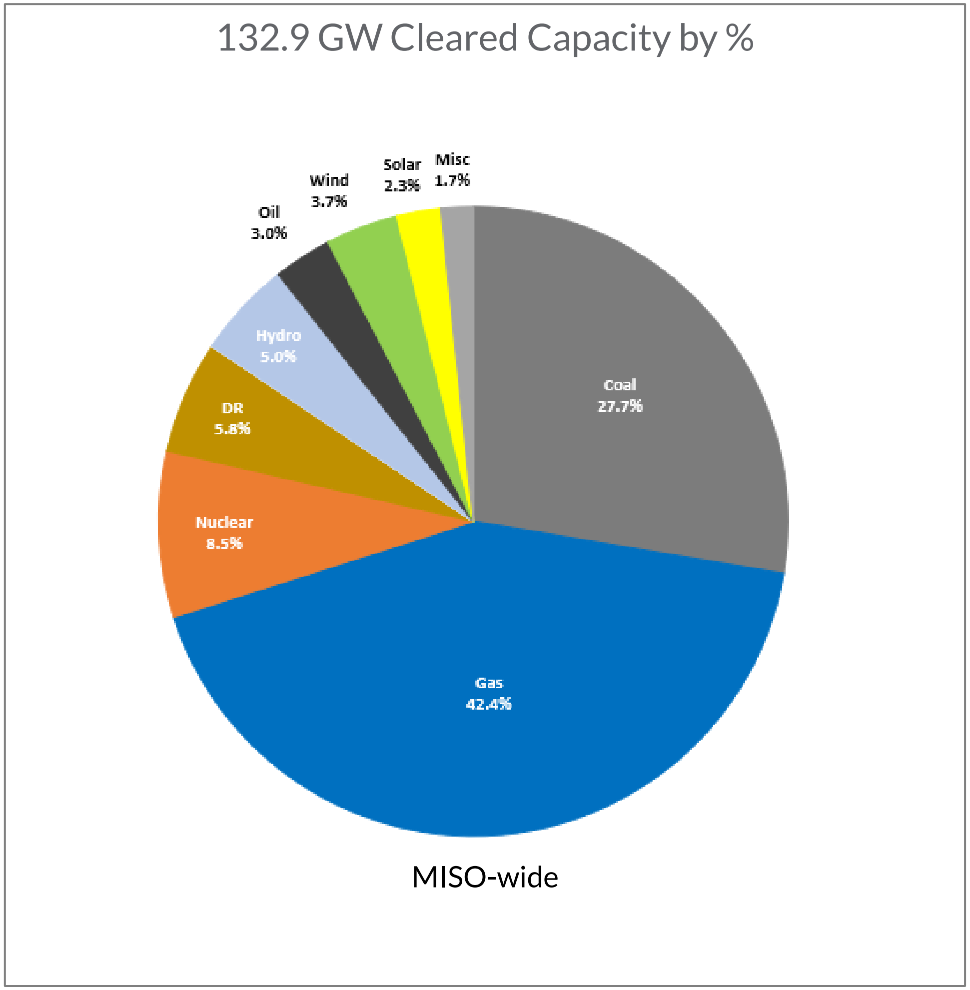


	Summer 2023	Fall 2023	Winter 2023-24	Spring 2024
Cleared Non-Self Scheduled	7,119.7	8373.5	3838.6	7474.1
Self Scheduled	90,974.8	85632.5	91537.4	85179.4
FRAP	34,796.7	31789.4	32728.2	31735.6

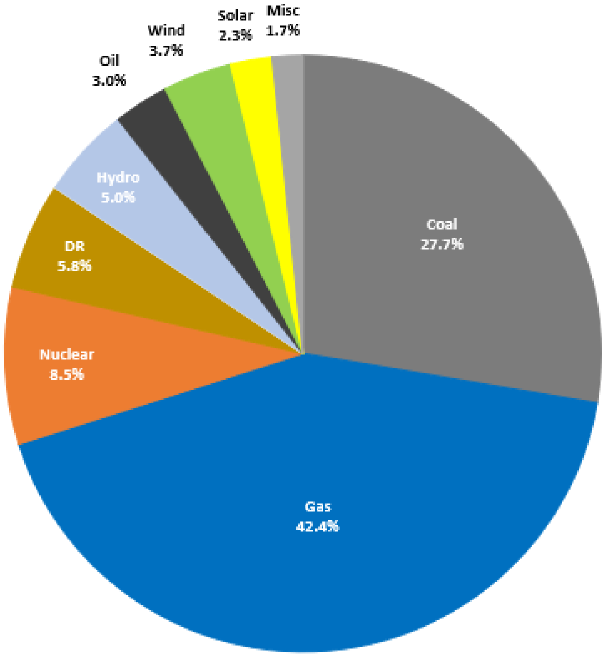
For the Summer 2023, although conventional generation still provides most of the capacity, wind and solar continue to grow

- 3.0 GW of solar cleared this year's auction—an increase of 42% from Planning Year 2022-23 (2.1 GW)
- Similarly, 5.0 GW of wind cleared this year, an increase of 32% compared to last year (3.8 GW)





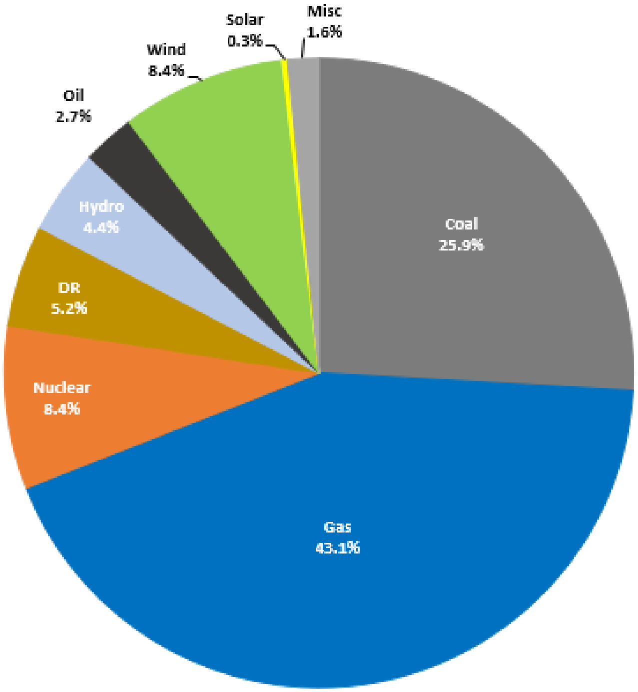
Winter PRMR is 4.8 GW (3.6%) lower than the summer. There were less thermal, hydro and solar resources and significantly more wind to meet PRMR in the Winter versus the Summer.



Summer 2023
Cleared Capacity

MISO-wide

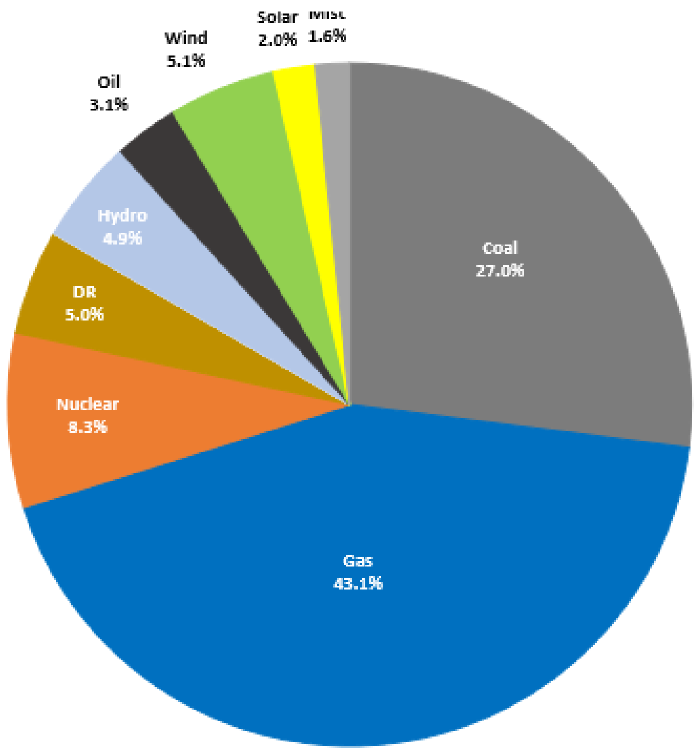
Cleared ZRCs	Summer 2023	Winter 2023-24	Difference
Coal	36,749.7	33,177.9	3,571.8
Gas	56,384.1	55,276.0	1,108.1
Nuclear	11,317.7	10,708.4	609.3
DR	7,694.6	6,702.4	992.2
EE	5.0	6.7	-1.7
Hydro	6,604.1	5,599.4	1,004.7
Oil	3,980.1	3,423.6	556.5
Wind	4,952.2	10,800.2	-5,848.0
Solar	3,008.2	371.8	2,636.4
Misc	2,195.5	2,037.8	157.7
PRMR	132,891.2	128,104.2	4,787.0



Winter 2023-24
Cleared Capacity

MISO

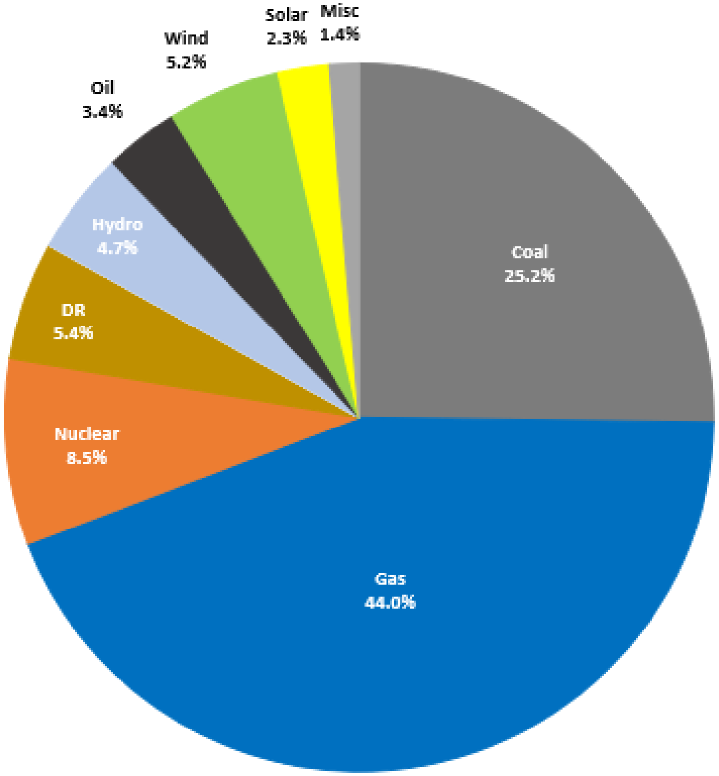
Fall 2023 and Spring 2024 - Cleared ZRCs and PRMR



Fall 2023
Cleared Capacity

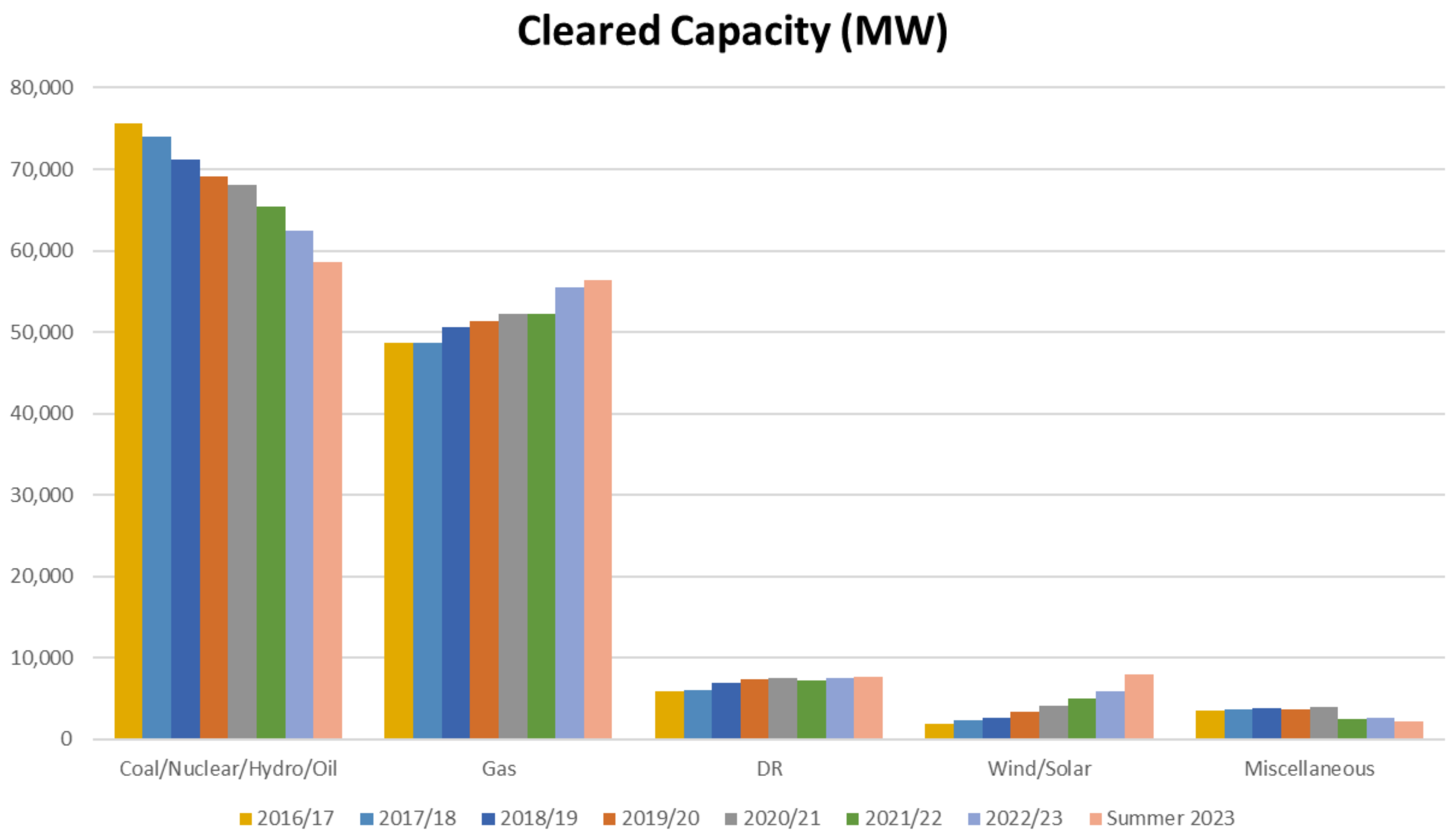
MISO-wide

Cleared ZRCs	Fall 2023	Spring 2024
Coal	33,978.5	31,366.6
Gas	54,243.2	54,701.3
Nuclear	10,382.2	10,539.4
DR	6,254.4	6,720.0
EE	4.8	5.3
Hydro	6,223.3	5,850.4
Oil	3,837.9	4,207.9
Wind	6,357.1	6,413.1
Solar	2,485.8	2,903.8
Misc	2,028.2	1,681.3
PRMR	125,795.4	124,389.1

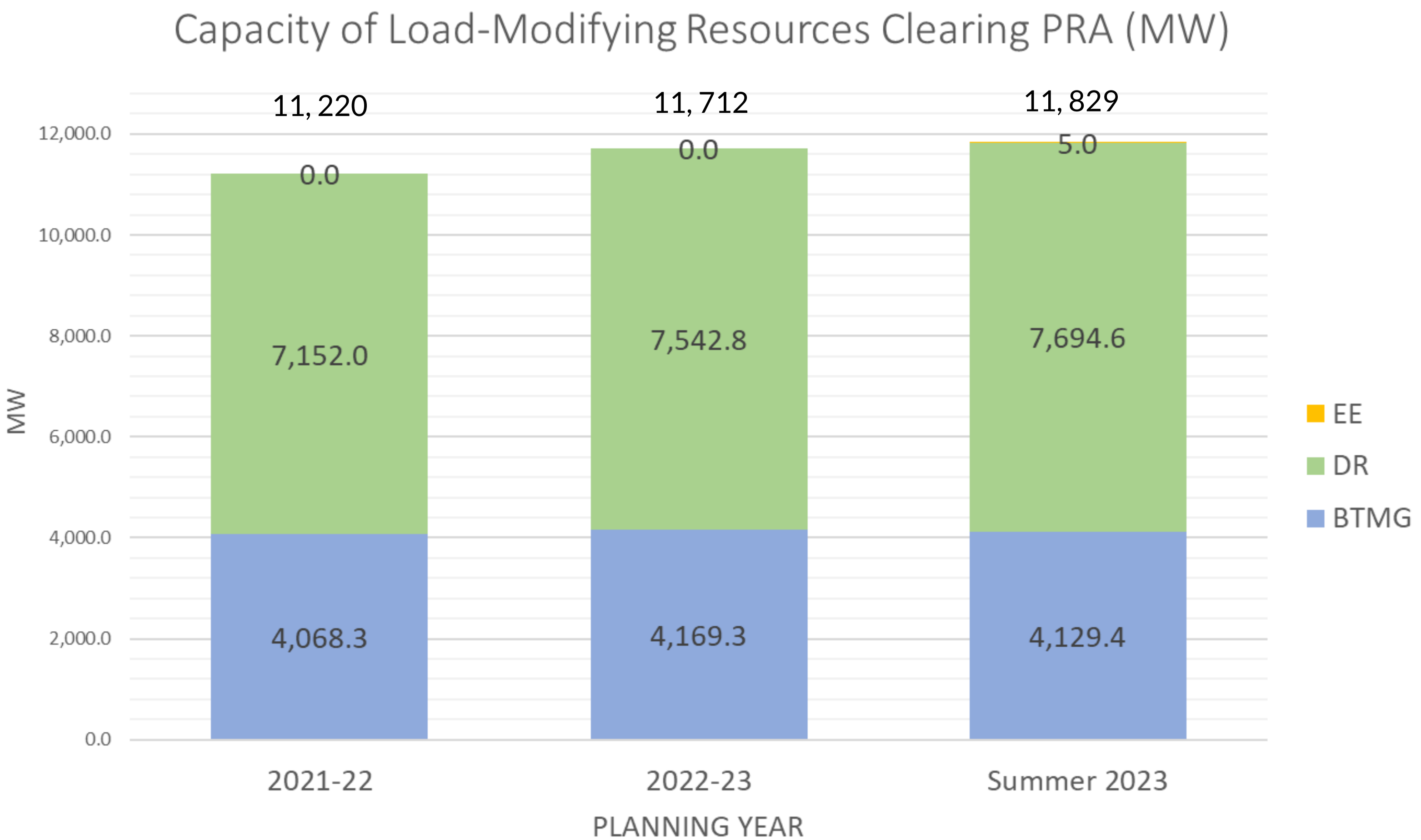


Spring 2024
Cleared Capacity

The planning resource mix shows the continuation of a multi-year trend toward less coal/nuclear/hydro/oil and increased gas and non-conventional resources

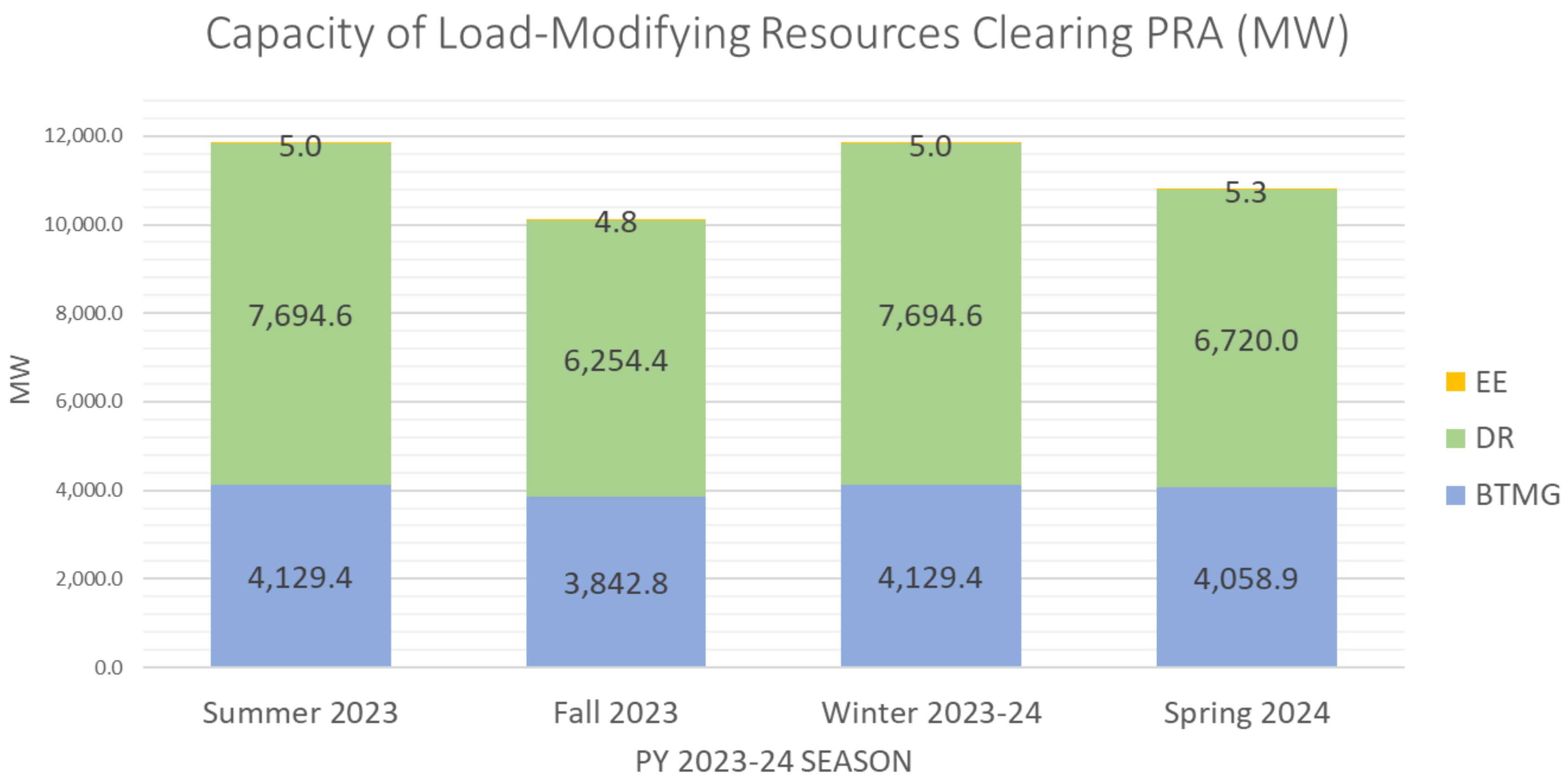


Historical trend for LMRs (DR, EE and BTMG) cleared in the PRA



Around 600 additional DRs were offered in for the 2023-24 PRA that did not clear the auction.

2023-2024 Seasonally Cleared LMR Comparison



Study Reports

- **LOLE Study Report**
  - https://cdn.misoenergy.org/PY%202023%202024%20LOLE%20Study%20Report626798.pdf
- **Wind & Solar Capacity Credit Report**
  - https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf
- CIL/CEL
  - https://cdn.misoenergy.org/20221003%20LOLEWG%20Item%2004%20PY%202023-24%20Final%20CIL-CEL%20Results_Updated626464.pdf
- SRIC/SREC
  - https://cdn.misoenergy.org/SRIC_SREC%20Posting%20for%202023_24%20PRA628233.pdf

https://help.misoenergy.org/support/