advanced energy management alliance

Advancing Demand Response in the Midwest

Expanding Untapped Potential

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Executive Summary

Energy leaders in the Midwest are actively preparing for the future electric grid, as demonstrated by initiatives at the Organization of MISO States (OMS) and the Midcontinent Independent System Operator (MISO). Regulators, utilities, and system operators face a growing set of challenges and opportunities that range from harnessing the deployment of Distributed Energy Resources (DERs) for the benefit of all customers, to avoiding increases in energy bills and controversial siting decisions despite expected generation retirements throughout MISO. Confronting these challenges and capitalizing on these opportunities will require innovative, technology-driven approaches.

Demand Response (DR) is a proven solution with new and untapped potential.[1] Leveraging the flexibility of customer loads can reduce energy bills and emissions; strengthen reliability, resilience, and economic competitiveness; and avoid interminable land use proceedings that attract negative attention. While not new to the Midwest, the growth and development of DR in the region has largely stagnated. Technological advancements and new, innovative business models for DR have created new value opportunities since the implementation of legacy interruptible programs in many states.

To create shared value for utilities and consumers, **states should take near-term action to create robust DR programs where DR is lacking and evolve DR program design in territories that have had the same tariffs for over a decade**. This whitepaper provides the roadmap for action, including

[1] FERC defines demand response as "changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." FERC, Reports on Demand Response and Advanced Metering, https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp. Demand response can be facilitated by load curtailments or distributed forms of generation, including behind-the-meter energy storage.

made-in-the-Midwest solutions. Using successful programs in Indiana and New York as examples, we will provide a template that states and utilities can follow to harness and maximize cost-effective DR participation in their territories.

AEMA's members, who have collectively delivered close to 20,000 MW of sophisticated DR solutions, have the experience and technological capability needed to maximize and advance DR for utilities and consumers across the Midwest. **AEMA is eager to collaborate with MISO-based utilities, regulators, and system operators in this endeavor.** Our goal is not to overturn existing bans that prohibit DR Providers from directly enrolling customers in wholesale market programs,[2] but instead to develop new creative approaches to exploiting the full potential of DR.

We will provide in this white paper:

- An overview of the benefits of DR;
- A summary of DR in MISO;
- Detail on how DR Providers can add value to utilities, consumers, and the grid; and
- Recommendations for maximizing the cost-effective, reliable deployment of DR in the MISO states, including the Indiana model tariff.

About Advanced Energy Management Alliance ("AEMA")

AEMA is a trade association under Section 501(c)(6) of the Federal tax code whose members include national distributed energy resource companies and advanced energy management service and technology providers, including DR providers, as well as some of the nation's largest demand response and distributed energy resources.[3] Over the course of the last year, AEMA has initiated discussions with key stakeholders throughout MISO to understand how DR currently participates in MISO states, and how we can collaborate to enhance the benefits of DR. This report is

[2] Commonly referred to throughout MISO as "Aggregators of Retail Customers," or "ARCs."
[3] For more information, visit AEMA's website: http://aem-alliance.org

an effort of a group of AEMA members and represents the collective consensus of AEMA as an organization, although it does not necessarily represent the individual positions of the full diversity of AEMA member companies.

Benefits of Demand Response

DR programs provide consumers financial incentives to voluntarily reduce or ''curtail'' their electricity usage during peak periods (*i.e.*, peak load management), during grid emergencies, or when needed to alleviate local transmission and distribution system constraints. Benefits from DR include:

Lower energy bills: DR has repeatedly proven to be a lower cost alternative to traditional generation, transmission, and distribution infrastructure. The Supreme Court, in its majority decision in *FERC v. EPSA*, recognized the important contribution of DR to just and reasonable wholesale rates and reliability.[4] Specific to the Midwest, recent reports completed by third party consultants found that commercial and industrial DR programs could deliver **net benefits of up to $316 million and $485 million for all customers** in Michigan and Indiana respectively over a 10-year period, much of it incremental to existing resources.[5]

In essence, **energy leaders in the Midwest should not let excess capacity stop them from pursuing all cost-effective DR**. New DR resources have become less expensive than continuing to run older, existing generation plants, as demonstrated by rapid resource transitions in other open markets. Taking into account the additional net benefits that DR resources provide to markets, states should maximize the market penetration of cost-effective DR.

Reliability and resiliency: In recent years, DR has helped the electric grid withstand extraordinary circumstances. PJM credited DR with helping to "maintain the reliability of the system" during the 2014 Polar Vortex when thermal generation experienced significant outages and fuel issues.[6] DR helped preserve reliability again after Hurricane Irma hit Florida in 2017.[7] As customers were rapidly having their power restored, demand threatened to outpace

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[4] Fed. Energy Regulatory Comm'n v. Elec. Power Supply Ass'n, 136 S. Ct. 760, 781, 784 (2016).

[5] Economic Potential for Peak Demand Reduction in Michigan, prepared for Advanced Energy Economy Institute by Demand Side Analytics, LLC and Optimal Energy, Inc. (February 16, 2017), http://info.aee.net/hubfs/PDF/Peak-Demand-Reduction-Potential-for-Michigan021717.pdf?t=1487398737782; Potential for Peak Demand Reduction In Indiana, prepared for Advanced Energy Economy Indiana by Demand Side Analytics, LLC (January 2018), https://info.aee.net/hubfs/IN%20DR%20Study%20Final.Feb.7.2018.pdf.

[6] Petition for Rehearing En Banc of PJM Interconnection, L.L.C. at 10-11, Electric Power Supply Ass'n v. FERC, No. 11-1486 (D.C. Cir. July 7, 2014).

[7] Energy Smart Blog, Following Hurricane Irma, Demand Response Stepped Up Amid Efforts to Restore Power, https://energysmart.enernoc.com/following-hurricane-irma-demand-response-stepped-amid-efforts-restore-power

supply due to generation outages, presenting another blackout risk at the worst possible time. Tampa Electric Company (TECO) dispatched DR to preserve grid stability until generation could come back online. Used properly, DR could provide similar benefits in MISO during emergencies.

Increased economic competitiveness: By providing direct payments to participating customers, DR allows consumers to keep their energy dollars in state, as opposed to flowing to out of state fuel producers. AEMA member companies have paid out billions of dollars to customers that have been reinvested in local jurisdictions. In one instance, a school was able to restore Advanced Placement courses with the revenue it received from participating in DR programs.

Risk mitigation and avoiding controversy: Regulators are seeking better ways to incorporate risk into investment decisions as controversies over new infrastructure development end up on the front page of newspapers. New infrastructure passes costs along to consumers for decades, when the need may not materialize or the costs of alternative solutions could rapidly decrease during that time-period. Since DR does not require major capital investment nor invite controversial siting disputes and can be quickly built up or scaled down, DR offers a low risk and consumer-friendly way to meet emerging power needs.

Renewable integration and carbon emissions: Grids will need more flexibility to integrate renewables without spilling energy and raising balancing costs. A Navigant Consulting study found that using DR to provide ancillary services could increase system flexibility and enhance MISO's ability to integrate and balance wind.[8] The same study found that DR could also directly reduce annual CO_2 emissions by more than 1% throughout MISO depending on penetration and the total hours of dispatch. In order to take advantage of this potential, however, DR in MISO will need to evolve.

States that are not pursuing all cost-effective, reliable DR are not capturing the full range of benefits. The following section reviews the current state of DR across the Midwest at the wholesale level.

Demand Response in the Midwest Region

In 2016, MISO had 10,721 MW of wholesale demand response capacity, equal to 8.9% of its annual load peak[9] and more than any RTO in the US. Most of it comes in the form of interruptible load and Behind-The-Meter-Generation (BTMG), developed under state-regulated and utility-run DR

[8] Navigant Consulting, Carbon Dioxide Reductions from Demand Response (November 2014), http://www.ieca-us.com/wp-content/uploads/Carbon-Dioxide-Reductions-from-Demand-Response_Navigant_11.25.14.pdf.
[9] Potomac Economics, 2016 State of the Market Report for the MISO Electricity Markets at 17 (June 2017), https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-SOM_Report_Final_Rev.pdf.

programs and accredited as Load Modifying Resources (LMRs) or Emergency Demand Resources (EDRs) in MISO.[10] MISO relies on these resources to be available and perform during emergency conditions. There are also 600 MW of DR that can participate in MISO's energy and reserves markets as Demand Response Resources (DRRs). These are sophisticated and reliable resources that are fully integrated with the wholesale markets, but only make up a small percentage of the total DR throughout MISO.

While utility interruptible DR programs are valuable for meeting capacity needs, they and the MISO LMR product have not evolved over the years like DR programs in other global markets. Table 1 below highlights significant differences between the emergency DR product requirements in MISO versus other US markets. While other markets have tightened their requirements to increase the operational value of DR, the utility interruptible programs that underpin LMRs have seen minimal change. Limitations to the MISO LMR product include:

- **Lead-time.** MISO allows customers to receive up to 12 hours of advance notification before being dispatched for DR, limiting the operational value to system operators. If events necessitate a response from DR in near real-time, MISO may not be able to access the resource. Certain utility interruptible tariffs already require customers to be capable of being interrupted much more rapidly.

- **Technology**. The programs generally have low technology requirements, which limits the visibility of the resource to grid operators and utilities. More advanced technology could help enable resources to participate in faster-responding programs used to balance renewables.

- **Testing.** As shown in Table 1, unlike every other wholesale capacity market, there is no requirement in MISO to annually dispatch all DR to ensure that participating customers can reduce their enrolled demand when dispatched. We expect that the majority of enrolled customers can be relied upon, especially customers that already reliably participate in the energy and ancillary market. However, testing ensures that customers who cannot meet their curtailment plans are not enrolled in programs beyond their capability. While some customers might push back against this requirement, it is in their and all consumers' best interests for resources to be fully prepared to perform in a system emergency.

[10] Over 90% of DR in MISO comes from BTMG and interruptible load registered under MISO's LMR construct.

- **Availability.** LMRs are only required to be available for five dispatches during the summer season. However, reserve margins in MISO tend to be lowest during the spring and fall, as evidenced by emergency conditions in April and September of 2017. This limits MISO's ability to call on a sizable portion of its capacity resources during times when they might be needed. Other ISOs have moved to 24/7/365 availability requirements with no dispatch limitation despite also having summer peaking systems.

Table 1. Comparison of U.S. emergency DR programs

Market	Dispatch Lead time	Resource availability	Dispatch limits	Audit requirement
MISO (LMRs)	Up to 12 hours	June-August	20 hours or 5 dispatches	No physical test required
NYISO (SCR)	2 hours	Year-round	Unlimited	1-2 per year if not dispatched
ISO-NE	30 minutes	Year-round	Unlimited	1-2 per year if not dispatched
PJM (CP)	30 minutes	Year-round	Unlimited	1 per year if not dispatched

There is a growing recognition of these limitations throughout the Midwest. Efforts to increase the situational awareness of DR throughout MISO, such as monthly LMR drills,[11] improve market participants' event readiness but need to go further. On-going conversations about resource availability and need at MISO are a good opportunity to look at the role that LMRs play in the market,[12] and whether changes are necessary to meet evolving reliability challenges and prevent risk and cost socialization across state borders.[13] Although MISO has only dispatched LMRs once in the

[11] These drills involve sending market participants (MPs) LMR drill implementation messages and asking them to acknowledge their LMR availability and obligation. It does not require MPs to dispatch their LMRs.
[12] MISO, Resource Availability and Need Issue Summary, https://cdn.misoenergy.org/20180124%20SC%20Item%2004b%20RAN%20Issue%20Summary105468.pdf.
[13] There is already some evidence of this: the dispatch-limited nature of the LMR product contributed to an increase in MISO's PRM from 7.8% to 8.4% for the 2018/2019 Planning Year.

last ten years,[14] they are likely to play an increasing role in MISO as surplus capacity dissipates,[15] and must be fit for their intended purpose.

The success of utility DR programs can be dependent, at least in part, on coordination and integration with the evolving wholesale electric market.[16] We applaud OMS and MISO for recognizing that any dialogue about wholesale programs should therefore consider retail programs and vice versa. At the same time, state commissions can lead DR efforts without waiting for changes at the MISO level, as some states such as Missouri are already doing. Commissions could institute proceedings to examine legacy DR program structures, costs, and performance, and whether the programs are sufficient to meet their evolving needs. The rest of this paper will describe how utilities, DR Providers, and regulators can collaborate to accomplish these goals.

DR Providers Can Provide Value to Utilities, Consumers, and the Grid

AEMA recommends a path forward that fosters collaboration between DR Providers, utilities, consumers, and MISO. A collaborative approach would allow MISO states to capitalize on the hundreds of millions of dollars that DR Providers have invested in DR technology and market expertise, while ensuring that DR is well integrated into utility planning and operational processes. It is not prudent for ratepayers to pay for utilities to make these investments when they are readily available from DR Providers. In this section, we will detail how DR Providers can provide value. The next section addresses some forms of potential collaboration in light of bans on DR Providers enrolling customers directly in wholesale markets.

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[14] LMRs were dispatched in April 2017 for the first time since 2006 due to higher-than-expected load and forced generation and transmission outages. The dispatch in April was outside of the LMR mandatory response window; only those reporting voluntary availability were dispatched.

[15] Potomac Economics, 2016 State of the Market Report for the MISO Electricity Markets at 74 (June 2017), https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-SOM_Report_Final_Rev.pdf

[16] Lawrence Berkeley National Laboratory, Coordination of Retail Demand Response with Midwest ISO Wholesale Markets (May 2008), https://eta.lbl.gov/publications/coordination-retail-demand-response

DR Providers have fueled the considerable growth of cost-effective, reliable DR across the country in both regulated and deregulated states, and should be included in efforts to grow DR in MISO. The values of DR Providers include but are not limited to the following:

- **Increasing customer participation**: Many customers assume that they do not have the flexibility to participate in DR programs. Through working with thousands of customers in both wholesale and state level DR programs, and often employing engineers or Certified Energy Managers, DR Providers have gained expertise in helping customers discover and maximize flexibility, thereby increasing participation. DR Providers have considerable experience with recruiting smaller industrial and commercial customers who do not have the staff or the desire to participate in programs directly. In PJM, the overwhelming majority of DR customers that participate have less than 1 MW of DR capacity.

- **Utility and ISO visibility**: As noted previously, utilities and MISO currently do not have real-time visibility into customer performance during grid emergencies. DR Providers have invested private capital in technology that provides utilities and grid operators the visibility they need when the grid is at its most fragile state.

- **Risk mitigation**: By aggregating customers into a large portfolio, DR Providers are able to shield individual customers from the type of out of-pocket penalty risk that prevents many customers from participating. DR Providers can build a cushion into their portfolio, so if a customer is unable to perform, the overall resource can still perform and deliver as expected by utilities and grid operators.

- **Flexibility**: DR Providers can "play Tetris" with customer capabilities to maximize participation and meet program standards. For example, if one customer can only reduce consumption for three hours but there is a six-hour event, a DR Provider could pair that customer's capability with another customer with limited duration capability to deliver a continuous reduction across the dispatch period.

Recommendations for Maximizing Cost-Effective, Reliable DR

We will highlight two potential options for maximizing the amount of reliable and cost-effective DR deployed across MISO states. Both options align with the vertically integrated nature of MISO states by allowing utilities to play a central role, while leveraging the capabilities of DR Providers described in the previous section. Neither option would require state commissions to reverse prohibitions on third party DR Providers enrolling customers directly in wholesale markets. Many of these prohibitions were put into place during 2009-2011 due to a concern that utilities would not be able to account for DR in their system planning if third parties were enrolling customers directly in wholesale markets without utility involvement. Both options address this concern.

The first option is what we will call the "Indiana Model" based on Indiana & Michigan ("I&M") Power's[17] tariff in Indiana. This innovative tariff[18] has attracted robust participation at a small fraction of the cost of new generation and won a "Program Pacesetters" award from the Peak Load Management Alliance.[19] Indiana is analogous to many other MISO states in that it is vertically integrated and has a ban on DR providers enrolling customers directly in the wholesale market. While I&M is located in PJM, the tariff could easily be modified for MISO state purposes, and the appendix includes a proposed model tariff based off the I&M tariff. The I&M tariff contains the following features:

- DR Providers that are qualified by I&M are allowed to sign up retail customers to participate in DR, but instead of the DR Provider enrolling the customers directly with PJM, they must register the customer with I&M who subsequently enrolls those customers in the PJM DR program. This enables I&M to incorporate DR into their planning and operational processes, providing them with visibility and dispatch control over the resources.
- By enrolling the customers in the PJM program, I&M receives capacity credit, and offsets the amount of capacity they need to procure from the wholesale market or build/maintain.
- I&M compensates DR Providers at the higher of the average of the PJM capacity market clearing price over the last four years or 35% of Net CONE (Cost of New Entry), which represents the assumed cost of building new generation. Therefore, I&M uses DR as a cost-effective alternative to retaining or constructing expensive generation. DR Providers typically pass along a majority of the payments to end-use customers, boosting economic development in Indiana.

[17] Indiana & Michigan Power is a subsidiary of American Electric Power.
[18] "Rider D.R.S.1 (Demand Response Service – Emergency)" at 98, https://www.indianamichiganpower.com/global/utilities/lib/docs/ratesandtariffs/Indiana/IM_IN_TB_16_01-30-2018.pdf.
19 PLMA, 14th PLMA Award Winners in April 2017, https://www.peakload.org/2017-winners.

This type of tariff, open to all customers over a certain size[20] represents an effective means for stimulating cost-effective DR while working within existing state and MISO market constructs.

The I&M tariff is focused on capacity, and MISO states and utilities could adopt a similar capacity tariff that receives LMR credit. The tariff could also serve as a foundation for a broader set of innovative services if so desired by a Commission or utility, such as peak load management, distribution-level services, or eventually additional wholesale market programs. Several other states have highly cost-effective DR tariffs and/or utility programs that supplement wholesale capacity programs. For instance, New York's Distribution Load Relief Program (DLRP) and Commercial System Relief Program (CSRP) offer good models for how to leverage DR and DERs to defer or avoid network upgrades. These programs focus primarily on reducing transmission and distribution costs and are independent of wholesale capacity programs. Like the Indiana Model, the New York programs have seen significant success, as demonstrated by Con Edison's projection of $163 million in net benefits over a ten-year period and the New York Commission's recent expansion of programs modeled on Con Edison's tariff statewide.[21] In our model tariff, we have modified the I&M tariff to include this type of peak shaving so that the tariff is designed to avoid generation, transmission, and distribution costs.

Commissions could work with stakeholders to develop an appropriate compensation level for DR, tied to the utility-specific or statewide avoided costs of capacity, or other avoided costs if the tariffs require additional dispatch beyond LMR. The goal should be to provide a transparent investment signal for participants and ensure utilities can attract firm DR at a clear discount to traditional infrastructure.

[20]While many utilities run DR programs for residential and small commercial customers, this white paper focuses on solutions to maximize programs for larger commercial and industrial customers.

[21] Consolidated Edison Company of New York, Inc., Report on Program Performance and Cost Effectiveness of Demand Response Programs – 2017.

An alternative approach is bilateral contracting between a utility and a single DR Provider, as is done throughout many states, including some in MISO.[22] Under this scenario, the utility and the DR Provider agree in a contract to a specific number of MW for enrollment, a price per MW, and program design, including when to dispatch the program. The design is a function of the utility's objective. If it is simply to receive capacity credit, then avoided capacity cost determines compensation, and the program should align with MISO requirements. If the objective is to reduce peak demand and avoid a broader set of investments than just capacity, then there is more dispatch and compensation would reflect the broader set of avoided costs. With the accountability inherent in a contract, this option allows for more precision in resource planning, as a single party is responsible for delivering the agreed number of MW. This can be an especially effective approach for smaller utilities where there may be too few prospective DR customers to support robust competition from DR Providers.

Both of these options can achieve the objective of maximizing cost-effective, reliable DR. While the bilateral option allows greater planning certainty, the I&M model has the potential to stimulate more DR through increased competition.[23] We would not recommend implementing both a bilateral contract and the Indiana model in the same utility territory. There are four important design considerations for both options:

1. Compensation for the programs should be a function of the actual avoided costs and net benefits resulting from the programs. Compensation based only on the MISO capacity price will fail to stimulate the market, as that capacity price is not reflective of the actual costs of capacity that customers pay for on their bills.

[22] The Montana-Dakota Utilities Company (MDU) contracts with CPower and Consumers Energy contracts with EnerNOC for the provision of DR programs and services are such examples.
[23] In order for there to be increased competition, a tariff needs to be adopted across an area with a meaningful enough customer base that it warrants multiple providers incurring the start-up costs associated with a new program.

2. Utilities should earn incentives for DR program success or receive permission to treat it as a capital expense. Otherwise, DR can adversely impact utilities' profitability when compared to a situation in which they can rate base investments in generation, transmission, or distribution.

3. The programs should be audited at least annually to ensure that the MW enrolled in the program are fully deliverable and can be relied upon during an emergency event. As discussed above, MISO is the only ISO with a capacity market that does not have an audit requirement for emergency DR resources. Regardless of MISO's approach, states should implement annual testing to protect reliability.

4. While DR Providers can add significant value to DR programs (see Section III), they are only attracted to markets in which there is sufficient DR potential to develop a financially viable portfolio of DR resources that can cover the fixed and variable costs of their operations. The existence of legacy interruptible programs in some utility territories may dull DR Provider interest in new programs. Utilities and commissions should consider whether transitioning legacy interruptible schedules to a more modern, technologically advanced program would serve all consumers better by maximizing the amount of cost-effective DR in the market.

Conclusion and Summary of Recommendations

To confront upcoming grid challenges and capitalize on opportunities, Midwest states should take action to maximize their DR resources and use them effectively. DR Providers and utilities can accomplish this through partnership models that create shared value and deliver consumer bill savings, improve system reliability and resiliency, and drive positive economic and environmental outcomes for communities. States can adapt the partnership models provided in this paper to realize those benefits. Below, we summarize five key recommendations provided in this paper.

Recommendations:

1. During resource planning processes, consider how DR could drive bill savings by replacing inefficient existing generation in addition to avoiding new capacity and transmission and distribution investments;

2. Open working dockets to evaluate the status of existing DR and DER resources and consider alternative models such as the ones provided in this document;

3. Promote competition in the provision of DR services and leverage the experience of DR Providers by adopting tariffs similar to the Indiana Model or bilaterally contracting for DR;

4. Review how utilities are incentivized to pursue demand-side solutions and provide frameworks to promote equal treatment with supply-side resources; and

5. Improve DR program standards to increase the reliability, flexibility, and value that DR resources provide to states and the wholesale market.

By implementing these recommendations, states in the Midwest can fully tap into the potential of DR to the direct benefit of their consumers, the utilities, and third party providers.

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Appendix A

Model Tariff for Utilities in the MISO region[24]

RIDER D.R.S.1

(Demand Response Service – Emergency and Peak Shaving)

Availability of Service

Available for demand response service (DRS) to customers in good standing, as determined by the Utility, taking firm service from the Utility under Tariffs *[insert applicable tariffs here]* who have the ability to curtail load under the provisions under this Rider. Each customer electing service under this Rider shall contract for a definite amount of DRS capacity, not to exceed the customer's maximum demand capable of being curtailed.

The Utility reserves the right to limit the aggregate amount of DRS capacity contracted for under this Rider and *[insert other capacity-based DR riders for C&I customers]* to *[insert number]*. The Utility will take DRS requests in the order received. The customer's DRS capacity under this Rider will be enrolled in the Midcontinent RTO (MISO) Load Modifying Resource (LMR) Program through the Utility. The Utility further reserves the right to limit registrations should MISO restrict the Utility from registering customers in any MISO product type. Customers participating in this Rider may elect to use the services of an Aggregator of Retail Customer (ARC) provided that such arrangements do not violate the terms and conditions of this Rider.

An ARC is an entity that the customer has designated to facilitate all or some of the customer notifications and transactions under this Rider and that is qualified as an ARC with MISO. The customer must provide written notice to the Utility of any such designation. Such written notice shall specify the authority that the customer has granted to the ARC, including any authority to access customer data.

The term "participant" as used herein shall mean the customer or customer-designated ARC as defined above. The participant is ultimately responsible for compliance with the terms and conditions of this Rider, including any charges under this Rider, in which the customer has voluntarily elected to participate.

Conditions of Service

(1) The provisions of this Rider qualify under the MISO Load Modifying Resource Program as of the effective date. The Utility reserves the right to make changes to this Rider in order to continue to qualify under the MISO Load Modifying Resource Program, or otherwise, as appropriate.

(2) The Utility reserves the right to call for (request) participants to curtail their DRS load when an Emergency event has been declared by MISO or when a response is needed to mitigate peak demand conditions within the Utility's territory.

(3) The Utility will endeavor to provide as much advance notice as possible of curtailments under this Rider including an estimate of the duration of such curtailments. However, the participant's DRS load shall be curtailed within 60 minutes if so requested.

(4) All curtailments will apply for the planning year (PY) which is defined by MISO as May 1 through April 30 of the following year. Contracts will apply for multiple planning years.

(5) In no event shall the participant be subject to MISO initiated load curtailment (MISO event) under the provisions of this Rider for more than the amount specified in the DRS Product and Payment

[24] We provide this tariff as a potential template that resembles the I&M tariff. We recognize that different jurisdictions may wish to amend the tariff for their own purposes.

Details table. The participant must agree to be subject to DRS curtailments pursuant to the *DRS Product and Payment Details* table herein.

(6) The Utility will inform the participant regarding the communication process for notices to curtail. The participant is ultimately responsible for receiving and acting upon a curtailment notification from the Utility. The participant is not responsible in the event the Utility fails to properly issue a curtailment notification.

(7) All customer metering demand data required under this Rider shall be determined from no less than five-minute integrated metering with remote interrogation capability and demand recording equipment. If a customer does not have five-minute metering and wishes to participate under this Rider, upon request, the Utility will install such metering equipment for individual accounts contracting for 50 kW or more at no cost to the customer or participant and for accounts contracting for less than 50 kW, a fee of $750.00 paid in advance shall be required.

(8) During each planning year the Utility will conduct a physical test and verify the participant's ability to curtail their Registered kW. However, if a curtailment event is called by MISO prior to the test, then the response to the curtailment event shall be considered the test for the planning year. These tests must be conducted for no more than one hour on a weekday between 12 noon and 8 p.m., in the customer's local time zone, from June 1 through August 31 during the planning year. If the participant's test performance is less than their Registered kW, the participant must elect to re-test their capabilities before August 31st to demonstrate their full Registered kW or will receive a Monthly Non-Compliance Charge as defined in this tariff.

(9) The Utility reserves the right to re-test participants that fail to comply during a test.

(10) If the participant fails to comply with the provisions of curtailment under this Rider, the Utility and the participant will discuss methods to comply during future events. If the problem cannot be resolved to the Utility's satisfaction, the Utility reserves the right to adjust the participant's committed kW amount or discontinue service to the participant under this Rider. Such adjustments or terminations will be charged as outlined under the Monthly Non-Compliance Charge provision.

(11) The minimum DRS capacity contracted for under this Rider will be 100 kW. Customers with multiple electric service accounts may aggregate those individual accounts to meet the 100 kW minimum DRS capacity requirement under this Rider; however, the DRS capacity committed for each individual account shall not be less than 25 kW. Aggregation with multiple individual electric service accounts, not under common ownership, must designate a MISO qualified ARC who shall be responsible to facilitate all of the customer notifications and transactions under this Rider. An ARC that creates an aggregation will provide to the Utility a Registered kW. The Registered kW represents the amount of Curtailed Demand the ARC desires the Utility to register with MISO and shall be the amount of Curtailed Demand, plus MISO's reserve margin, that is the basis upon which participants are paid under this Rider.

(12) In addition to curtailments under Item 2 above, the Utility reserves the right to call for (request) participants to curtail their DRS load when, in the sole judgment of the Utility, an emergency condition exists within its Local Balancing Authority territory. The Utility shall determine that an emergency condition exists if curtailment of load served under this Rider is necessary in order to maintain service to the Utility's other firm service customers according to the Utility's Emergency Operating Plan. During such event, the participant must make best efforts to voluntarily curtail DRS load.

(13) NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE UTILITY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS RIDER.

DRS Product and Payment Details

Product component	Curtailment availability	Maximum number of curtailments	Dispatch Trigger	Hours of day required to respond	Maximum duration of curtailments	PY 18/19 capacity payment ($/kW-month)	PY 18/19 event payment ($/kWh)
Load Modifying Resources	Any day during June – August of PY	5	MISO LMR Dispatch or LBA Emergency	24/7	4 hours	[Insert price here] [25]	$0.125
Utility Peak Shaving	Any weekday during May – September of PY	10	96% of Utility System Peak[26]	2p to 8p	4 hours		

The Curtailment Demand Payment shall be calculated in $ per kW-month as the greater of (a) the four-year average PRA Clearing price for the applicable locational zone, calculated using the preceding planning year, the planning year and the subsequent two (2) planning years and (b) 50% of the MISO Cost of New Entry (CONE) for applicable zone of the planning year.[27]

Behind the Meter Generation

Participating customers, who operate Behind the Meter Generation (BTMG) for demand response purposes under this Rider, shall adhere to MISO rules governing the use of BTMG, and operate and in compliance with all local, state and federal laws including environmental permits. Adherence and compliance with MISO rules and all local, state and federal laws with regard to BTMG is the sole responsibility of the customer.

Exception to 60-Minute Notification to Curtail DRS Load

Participants will be required to fully respond to curtailment requests within 60-minutes of notification from the Utility unless an exception request has been approved by the Utility. The intent of these qualifying exceptions is to accommodate DRS customers with legitimate, physical reasons that prevent curtailing load within a 60-minute notification time period. The Utility may approve these exceptions in their sole judgment but is under no obligation to do so. An exception cannot be granted for more than an additional 60 minutes, for a total notification lead-time of 120 minutes.

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[25] As highlighted in our white paper, the price should result in a net benefit to all customers and offer a discount to building new generation while attracting customer participation. The I&M tariff pays the higher of the average of the last four years of the PJM auction or 35% of Net CONE, which results in a payment of approximately $35,000/MW-year. However, that is only for an emergency program that is rarely dispatched. The compensation for a peak shaving program which would result in more dispatch hours and more avoided costs, including transmission & distribution instead of just avoided generation, would likely need to be higher to attract meaningful participation.

[26] Each jurisdiction can decide what percentage of peak demand will yield the highest net benefits and customer savings. Peak shaving programs typically are called between 92% and 98% of peak demand. The higher the percentage, the less frequently the program will be called.

[27] 50% is a placeholder and would offer a significant discount to new capacity but as suggested in the footnote above, jurisdictions should develop compensation that is appropriate for their territory.

Customer Baseline Load Calculation

A Customer Baseline Load (CBL) will be calculated for each customer for each hour corresponding to each curtailment event hour. Normally, the CBL will be calculated for each hour as the average corresponding hourly demands from the ten (10) most recent similar non-event days in the period preceding the relevant curtailment event, with symmetrical multiplicative adjustments if desired. In cases where the normal calculation does not provide a reasonable representation of normal load conditions, the Utility and the participant may develop an alternative CBL calculation that more accurately reflects the customer's normal consumption pattern. All CBLs must conform with MISO rules and be approved by MISO.

Curtailed Demand

The participant's Curtailed Demand shall be determined based upon the Guaranteed Load Drop (GLD) method.

Guaranteed Load Drop Method

a. Each participant must designate a Guaranteed Load Drop (GLD), which amount shall be the minimum demand reduction that the participant will provide for each hour during a curtailment event or during a curtailment test.
b. If the participant fails to fully comply with a request for curtailment under the provisions of this Rider or does not reduce load by the full GLD, a non-compliance charge shall apply. For this purpose, Actual Load Drop (ALD) is defined as the difference between the participant's CBL and their actual hourly load. If the ALD is less than the GLD, the Event Non-Compliance Demand shall be equal to the average difference between the GLD and the ALD occurring during the hours of the curtailment event. Otherwise, the Event Non-Compliance Demand shall be zero (0).

Curtailed Energy

The Curtailed Energy shall be determined for each curtailment event hour, defined as the difference between the participant's CBL for that hour and the participant's metered load for that hour.

Curtailment Payment

The Curtailment Capacity Payment and Curtailment Event Payment shall be as shown in the DRS Product and Payment Details table.

Monthly Demand Payment

The Monthly Capacity Payment shall be applicable to each month the customer and participant is served under this Rider, regardless of whether or not there are any curtailment events during the month.

(1) Guaranteed Load Drop Method – The Monthly Capacity Payment shall be equal to the product of the GLD and the Curtailment Demand Payment.

The Utility reserves the right to withhold Monthly Capacity Payments from any customer or participant who is indebted to the Utility for any service rendered at any location contracted under this Rider. If the customer's or participant's indebtedness to the Utility has not been resolved by April 30 of the current planning year, all Monthly Demand payments outstanding shall be forfeited.

Monthly Event Payment

An Event Payment shall be calculated for each event hour equal to the product of the Curtailed Energy for that hour and the Curtailment Energy Payment for that hour. The Monthly Event Payment shall be the sum of the hourly Event Payments for all events occurring in the calendar month. Event Payments will not be withheld if the customer's DRS capacity is already reduced as a result of customer actions taken in anticipation of a curtailment.

Monthly Non-Compliance Charges

Charges for non-compliance will be based on all charges passed down from MISO to the utility plus the Non-Compliance Demand for all dispatch hours related to peak shaving or testing. The participant's Non-Compliance Demand reflects any failure by the participant to fully comply with requests for curtailment. The Monthly Non-Compliance Charge shall be equal to the average Non-Compliance Demand across all peak-shaving event or test hours for that month times the Curtailment Capacity Payment. The Non-Compliance Charge will be assessed as an offset to monthly payments.

Settlement

The net amount of the Monthly Capacity Payment and Monthly Non-Compliance Charge will be provided to the participant by check or electronic payment within 60 days after the end of the delivery month.

Term

Contracts under this Rider shall be made for an initial period of four (4) planning years and shall remain in effect until either party provides three (3) years' written notice prior to March 1 of its intention to discontinue service under the terms of this Rider for the next planning year beginning after the notice is provided. Written notice deadlines through March 1, 2020 are as follows:

Written Notice Deadline	Effective Date of End of Service under Rider
March 1, 2018	April 30, 2021
March 1, 2019	April 30, 2022
March 1, 2020	April 30, 2023
March 1, 2021	April 30, 2024

If a customer or participant becomes ineligible for service under this Rider during the term of a contract under this Rider, the Utility reserves the right to terminate such contract immediately.

Special Terms and Conditions

Customer and participant specific information, including, but not limited to DRS contract capacity, shall remain confidential.

If the participant will have reduced availability, below their Registered kW obligation, for any hour of the planning year, then the participant must notify the Utility at least 18 hours prior to the hours in which availability will be limited, so that the Utility can communicate the new information to MISO accordingly. Requests for reduced availability made with less than 18 hours advanced notice will attempt to be processed with a good faith effort, but the Utility has no obligation to do so.

If a new peak demand is set by the customer in the hour following a curtailment event due to the customer resuming the level of activity prior to the curtailment, the customer may request, in writing, that the customer's billing demand be adjusted to disregard that new peak. The Utility will promptly evaluate all such requests and approve reasonable requests. In specific circumstances and subject to reasonable conditions, the Utility may approve requests in advance.