MI POWER GRID

Making the Most of Michigan's Energy Future

Demand Response Report

MI Power Grid Stakeholder Group

U-20628

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MPSC

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Contents

Executive Summary

On October 17, 2019, the Michigan Public Service Commission (MPSC) launched MI Power Grid in collaboration with Governor Whitmer. MI Power Grid is a customer-focused, multi-year stakeholder initiative intended to ensure safe, reliable, affordable, and accessible energy resources for the state's clean energy future. The initiative is designed to maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses. MI Power Grid encompasses outreach, education, and changes to utility regulation by focusing on three core areas: customer engagement; integrating new technologies; and optimizing grid performance and investments. The MPSC maintains a dedicated website for the initiative at www.michigan.gov/mipowergrid.

MI Power Grid seeks to engage a variety of stakeholders, including utilities, energy technology companies, customers, consumer advocates, state agencies, and others, in discussions about how Michigan should best adapt to the changing energy industry. Stakeholder groups are formed and led by MPSC Staff. This report highlights the efforts of the MI Power Grid Demand Response (DR) Stakeholder Workgroup.

Using the Statewide Energy Assessment and its findings as a foundation, the MI Power Grid DR workgroup was tasked with finding solutions to demand response underperformance during Polar Vortex 2019. Various stakeholders were asked to present on their Polar Vortex experiences, particularly on any lessons learned or problems encountered during the event. As a result of a series of meetings, it came to light that inaccurate resource availability and a breakdown in communication processes were responsible for the majority of underperformance. However, recent tariff changes at the Midcontinent Independent System Operator (MISO) and procedural changes by the utilities have been put into place since January 2019, with the goal of addressing the availability and communication problems brought to light in the assessment.

While these modifications are welcome and necessary, the workgroup highlighted several areas to improve upon these changes and ensure that demand response is able to perform at an exceptional level. The report calls for several enhancements to the utility-customer relationship, including more frequent communication, improved customer readiness procedures, and the incorporation of new technologies to streamline interactions with the customer before, during, and after an event. The report also recommends that utilities develop three key building blocks within their DR programs: real-time metering, customer readiness and a robust software platform to manage customer interactions. To the extent that these assets have not already been developed by the utility, the report recommends exploring cost-effective utility-DR service provider partnerships to take advantage of services already pre-built by these external entities.

While a strong utility-customer relationship certainly reinforces one aspect of DR performance, procedures and processes must also be in place to ensure the resource is able to perform when called upon. The report recommends that notification procedures and penalty provision be clearly articulated in each utility's respective tariffs and also highlights several areas where standardization of these processes may provide clarity to the customer and utility alike. To ensure the physical ability of a DR resource to perform during an event, utilities should also conduct an annual real power test or a documented simulation, taking the customer's testing burden into account when deciding between testing and simulation.

As Michigan's DR portfolio continues to expand and become more sophisticated, utilities should continue to explore multiple program options, including those in the capacity, energy, and ancillary services markets. The existing pilot process, as referred to by several stakeholders, provides a means for utilities to explore new options and provide added flexibility to their customers. To the extent that the Commission accepts the recommendations contained within, the necessary tariff changes could occur either within the general rate case process or an ex parte proceeding.

Recommendations

I. Ensure Load Modifying Resource (LMR) availability is properly accounted for in MISO's Communication System (MCS) tool
II. Ensure clarity and consistency in communication processes
III. Increase DR provider interaction with the customer
IV. Explore the use of enabling technologies where feasible and cost-effective
V. Direct utilities to explore DR partnerships for real-time metering, customer readiness, and a centralized platform
VI. Require an annual documented simulation and encourage real power testing where feasible
VII. Formalize and standardize the notification procedure and penalties in utility tariffs
VIII. Any necessary tariff changes should be made in a general rate case or an ex parte case
IX. Enable DR value stacking: capacity + energy + ancillary services

Introduction

The Michigan Public Service Commission (MPSC or Commission) issued an Order in Case No. U-20628 on September 11, 2019, that directed Staff[1] to convene a workgroup of utilities, regional transmission operators (RTO's), Demand Response (DR) providers, customer advocates, and other interested stakeholders to review and discuss the information contained in the final Statewide Energy Assessment (SEA) report regarding the reasons for the poor response of Load Modifying Resources (LMRs) to the 2019 Polar Vortex, and to discuss ways to improve future LMR participation and performance when deployment is required.

The Commission stated that the four objectives of the group would be as follows:

1) Ensure LMR participation and performance
2) Maximize the value of DR resources in wholesale markets
3) Improve communication with LMRs during times when their deployment is necessary
4) Discuss other issues related to DR as appropriate to achieve the Commission's overarching goals of reliability and resilience.

To achieve these objectives the Commission directed the workgroup to review DR tariffs for consistency and clarity regarding LMR deployment, consider how retail DR offerings can be better aligned with wholesale markets, examine communication procedures during DR events, and discuss ways to conduct testing of the communication and response system. Staff used these guidelines to prepare content for a series of stakeholder meetings, as described below.

MI Power Grid Demand Response Stakeholder Workgroup

The development of the MI Power Grid Demand Response Stakeholder Workgroup was a task approached methodically and deliberately. The internal DR team compiled a list of potential stakeholders that stemmed from the list of participants from the DR Aggregation Workgroup held in 2019. The internal DR team also held individual meetings with the entities specifically reinforced in the Commission's Order in Case No. U-20628 to develop a comprehensive listserv for this MI Power Grid DR Stakeholder Workgroup. Additionally, Commission Staff worked with the Commission's Communication Division to create a webpage[2] with additional resources and opportunities for interested stakeholders to sign up for the workgroup listserv. There are over 800 subscribers to the MI Power Grid DR listserv.

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[1]Commission Staff involved in this initiative consisted of an internal Demand Response Team, the team is cross divisional staffed with subject matter experts.
[2] Webpage [here](#).

Staff conducted a total of four stakeholder meetings over the course of four-months. The meetings included presentations related to the September 11, 2019 Commission Order U-20628, the SEA report, LMR operations, communications and testing, wholesale and retail tariff alignment, and DR aggregation. Stakeholder participation was outstanding with over 30 different entities represented throughout the four workgroup meetings. Commission Staff was able to transition of the workgroup meetings from in-person to web-based sessions in order to accommodate continued participation throughout Michigan's Stay At Home Order due to COVID-19.

Overview of DR Stakeholder Engagement Activities

State Energy Assessment (SEA)

Governor Whitmer requested that the Commission review the supply, engineering, and deliverability of Michigan's natural gas, electricity, and propane resources, a request that ultimately led to the development of the SEA report. The Commission was also requested to review other areas, including Demand Response performance during the weather event dubbed Polar Vortex 2019 (PV19). In the Electric Recommendations section of the Report (See 9.3.1.1), several recommendations were focused on improving DR. Some customers did not respond as required per their interruptible tariff, and upon further investigation, it was determined that there was an inconsistency in tariff language. As a result, several recommendations were made to improve DR programs (See E-1). Some of the other DR-specific Electric Recommendations included a review of the electric utility tariffs for consistency and clarity (See E-1.1), coordination among utilities, Staff, and stakeholders (See E-1.2), and recommendations for utilities to review their communication plan for efficient response during emergency events (See E-1.3).

Polar Vortex 2019 Overview

PV19 took place on January 30 and 31, 2019 resulting in temperatures in the upper Midwest that dropped below -25°F. On the Bulk Electric System, frigid temperatures caused unplanned equipment failures in parts of the Midwest region, which decreased expected electric generation to levels below the amount needed to maintain reliability. As a result, a system-wide (15 states) electric emergency was declared by the RTO, Midcontinent Independent System Operator (MISO), that required: 1) all available generation to provide electricity at maximum emergency capacity; and 2) certain entities to reduce demand according to applicable emergency tariffs. In response to this emergency declaration, Michigan's electric utilities required customers on interruptible rates to immediately reduce their electricity usage. Although the electric emergency was a regional event affecting both Michigan and surrounding states, Michigan was a net exporter of electricity during PV19, providing support for the region-wide emergency.[3]

[3] Michigan Statewide Energy Assessment

MISO, the utilities, DR service providers, and customers were asked to share their PV19 experiences at the workgroup meetings, particularly with regards to operational challenges encountered during the event as well as any gaps in communication procedures. Based on the presentations and discussion, each entities' respective experiences are summarized below.

MISO and its members were able to reliably serve load during PV19, yet some members had uncertainty in both load and supply, which created challenges throughout the event. Between January 29th and January 30th, MISO saw a 10 GW increase in outages. Additional outages prompted MISO to issue a Max Gen event, step 2a/b to access available LMRs. PV19 was the first time MISO had deployed LMRs in their North and Central Regions, and 75% of the scheduled LMR MWs responded to the emergency. For MISO's Zone 7, which includes most of Michigan's lower peninsula, 67 LMRs were deployed and 74% of the MWs requested by MISO responded to the event. For Zone 2, which includes Michigan's Upper Peninsula and the Eastern half of Wisconsin, 22 LMRs were deployed and 80% of the MWs requested by MISO responded to the event. After a system emergency, MISO conducts a post-event evaluation of each registered LMR to assess their performance and determine any necessary penalties. A MISO Market Participant (MP), the entity who supplies the DR to MISO, is required to submit meter data for the LMRs within 53 days after the operating day of the emergency event. MISO then assesses each LMR's performance based on the meter data submitted. MISO then contacts each MP once the evaluation is completed to confirm and discuss the results. Penalties are assigned to each LMR based on their metered performance with some LMRs being disqualified as a Planning Resource if their performance was substandard. The overall LMR penalties assessed for all of MISO North and Central Regions were $1,900,000 for underperformance and an additional $900,000 due to disqualification of 18 LMRs.

DTE Energy (DTE) received the MISO directive on January 30th, 2019 to interrupt LMRs and promptly sent interrupt notices to its customers. A Max Gen event was declared at 6:18 am and at 6:37 am instructions for LMR deployment were delivered from MISO. DTE notified their customers within 35 minutes of receiving the LMR deployment notification from MISO. This allowed interruptible customers 1 hour and 45 minutes notice to interrupt. The tools which DTE used to notify customers were an automated phone call followed by a call from the account representative. Direct load control (water heaters) were called at 8:00 am and then an hour later at 9:00 am, all other interruptible DR was also called. Representing a large percentage of the total DR registered in MISO, DTE achieved 66% of its scheduled interruptible load. Based on the results from PV19, DTE conducted a post event review that resulted in improvements to its LMR processes. DTE also implemented new communication processes, which include improved notice to the MPSC, modified message templates to indicate an actual system integrity event, enhanced internal direct communication to executives, improved existing process documents, modified its interruptible tariff language, and created specific talking points for its customer service department. DTE has additional improvements planned for the future. These future improvements include the development of SMS text options and conducting process improvements to using a 10 day rolling average to determine the hourly availability of LMRs which better aligns with MISO's

Metering and Verification (M&V) process. DTE is also supportive of shorter notification times for LMRs. DTE was able to provide appropriate notice to customers and reached 97% of its LMR customers. Account managers from DTE also personally called customers: DTE contacted 240 of 380 total customers, however 312 of 575 total customer sites did not respond or did not sufficiently respond to the event and were subject to DTE penalties. Penalties were paid immediately or via a payment plan. All customer penalty charges with the exception of one have been paid. Thirteen DTE customers have requested rate changes as a result of PV19 and eleven DTE customers have requested an interruptible rate product since PV19. Customer feedback received by DTE indicated that the company's messaging was not urgent enough. DTE has since reviewed and modified the urgency and clarity of their event messaging. DTE customers also felt that a one hour notice to interrupt is not long enough to shut down equipment properly. DTE also found that participating customers' contact personnel had changed since signing up to the interruptible rate. DTE account managers and other staff now meet with each customer annually and will include plans to discuss personnel contacts going forward. DTE has also discovered that smaller, less sophisticated customers need assistance with load reduction planning and will use the DTE internal group to work on outreach and training for its interruptible customers.

Consumers Energy Company (CE) stated that most underperformance for its customers came from the utility's failure to communicate effectively. Some of the key takeaways that CE had were the lack of understanding of when Max Gen events are happening and evaluating all the ways that Max Gen events can occur so its operators can respond.

> Problem 1: While the CE operators had received the LMR dispatch instructions from MISO, there was a significant delay relaying those notifications to the DR customer base. This delay occurred because the emergency event processes and notifications were dissimilar to how the CE merchant operations center had trained. Consequently, some DR customers did not receive the signal to reduce load until hours later, thereby missing a significant portion of the load reduction window.
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> Problem 2: Customers were notified of the emergency event on January 30th, 2019, but those customers did not realize that there was an expectation to perform during the morning period versus the afternoon. Additionally, CE communicated to MISO that it had a certain amount of load marked as available in the MISO Communication System (MCS) when in reality that level of load was not available because certain portions were only available during the summer via contract. These unavailability issues accounted for the largest portion of CE's underperformance. MISO served penalties on CE based on the amount of load it stated it could reduce and did not achieve. Penalties were collected from certain CE customers, but CE held most customers harmless if it was shown that there were communication errors or requirements to only respond during summer. CE found it important to provide the MCS with accurate LMR resource availability and also discovered gaps in its training that it intends to correct. CE has begun to implement a process to input accurate LMR availability data into the MCS year-round. After experiencing an emergency

event, CE recognized that the company could receive emergency communications in multiple ways, and these may not be the same as what its operators trained on. CE is enhancing communication processes for internal groups and implementing improvements due to lessons learned that do not require changes in tariffs.

Hemlock Semiconductor (HSC), a customer of CE, is the largest electric load in Michigan. HSC received the first notification at 4:58 am on January 30th, 2019 that there was going to be a Max Gen Event at 7:00 am. At 8:46 am HSC received notification from Consumers Energy of the actual event and began responding immediately. HSC has the capabilities of running at 400 MW and nominated to reduce 75 MW. HSC was able to achieve 100% compliance for its registered 75 MW during PV19. However, HSC had some issues with the virtual dashboard from CE, but had HSC engineers on staff to review the dashboard. They were concerned with operator safety during the cold weather. HSC refined its Standard Operating Procedures and developed new training scenarios. Currently HSC conducts trainings at least once a year. As a result of PV19, HSC had a loss of production and equipment damage resulting in $250,000. With regards to testing, HSC is not opposed to simulated testing or real power testing on a small scale but would prefer not to test the full 75 MW due to the heavy cost that the lost productivity would cause. In HSC's opinion, better economic price signals may be helpful to avoid a Max Gen event.

General Motors (GM) is a large customer of DTE and has been on their Rider 10 rate for more than 25 years. GM initially received event notices around 5:00 AM and was surprised to see a Max Gen event called during a winter month. In the Max Gen event, the interruption was communicated to GM through a series of calls. Both MISO and the utility called for interruption, which went to the GM Energy Manager. Then, the DTE representative followed up with a call and emailed the GM Energy Manager. GM used DTE Load Watch to monitor usage at its DTE sites and to anticipate interruptible situations. GM was able to meet the demand response reduction in part by closing down some production and sending employees home. One of the highest performing GM facilities took extreme actions due to the nature of the event and was able to shed 40% of the facility's load. GM also ran six 6 MW diesel generators to support its curtailment effort. With those efforts, along with other GM locations, GM was able to meet the interruption requirements. Some sites experienced increased gas consumption as a result of losing building heat when the electric use was cut. GM learned that it needs to work directly with plants as it reviews curtailment processes and adjust procedures for efficient reductions when called upon. GM also stated it needs to maintain strong relationships with utilities to ensure communication channels are open. GM welcomes opportunities to improve the Demand Response program offerings to better fit an industrial profile.

Voltus is a DR service provider and has a unique perspective related to LMRs. According to Voltus, a fundamental problem with DR is that it is not called upon routinely like a traditional generator. DR is traditionally dispatched only on peak, yet its performance when called upon is essential to preventing blackouts. Voltus compared interruptible rates to "flying blind", especially if the utility does not test their interruptible loads nor have real-time telemetry. While a DR provider[4] may have interruptible programs on the books, it is unclear which will be able to fully respond unless they are tested or used more frequently. Voltus also sees customer employee turnover causing communication problems with demand response programs on the customer and utility sides, similar to HSC and GM.

Voltus is focused exclusively on demand response and has developed the processes and tools to streamline demand response participation during emergencies like PV19. For example, Voltus has processes in place to test its resources each year, to update MCS availability daily, and to contact customers automatically and instantaneously in the event of a dispatch signal from MISO. Voltus also provides its customers with support in developing realistic load curtailment plans, which are reviewed at least annually. Voltus conducts multiple communications tests per year to ensure it has the most up-to-date customer contact information. Additionally, Voltus's customers are provided with real-time telemetry and a software platform where they can monitor their load relative to their demand response baseline and targeted load level during dispatch. Under current MPSC rules, Voltus may only serve customers who participate in the Choice program in Michigan. In recent years, however, FERC has restricted the ability of states to limit aggregation of Distributed Energy Resources (DER), including wholesale energy efficiency and storage, and FERC may extend that line of thinking to DR in the future. Voltus has advocated to the MPSC to eliminate its ban on aggregation for non-Choice customers. During PV19 Voltus was unaffected because in 2019 they only made their LMRs available for the three summer months.

Natural Gas and PV19

Another outcome of extreme conditions affecting the Bulk Electric System, like PV19, is a heavy strain on systems for delivery, transmission, and storage of natural gas. With the industry wide trend of retiring coal-fired generating resources and increased reliance on natural gas-fired electric generation, additional constraints on natural gas service further compounds emergencies for electric supply during extreme weather conditions. Furthermore, the two energy system constraints produce unique challenges for customers. For example, as previously discussed, HSC was able to respond to CE's call to interrupt electric service during PV19. However, HSC was also requested to reduce natural gas load under Consumers Gas' curtailment tariff on the same day. Even if a customer has both gas and electric service from the same company, there may not be enough communication between the two utilities within the company on how combination customers should be asked to curtail each service. This represents additional support for clear communication between not only the utility and customer, but within utility industries.

[4] For the purposes of this report, 'DR provider' means any company providing a DR program, including both utilities and third-party providers.

Following guidance from the SEA report, the Commission directed Staff to convene a workgroup to discuss the state of natural gas curtailment. The Natural Gas Curtailment Procedures Workgroup held several conferences consisting of regulated gas utilities, representatives of gas suppliers, customer groups, and Staff. One area of focus for the gas curtailment workgroup was identifying the appropriate priority level for curtailing service to electric generators. Staff's report containing recommendations stemming from the gas curtailment tariff workgroup was issued in the Order in Case No. U-20628 on June 30, 2020.[5] These recommendations address communication among utilities and their customers, as well as deem electric generation essential for public health and safety as highest priority for curtailment (i.e., curtailed last, in the same category as residential customers).

LMR Operations and Communications

In addition to the operational walkthrough summarized above, representatives from DTE, CE, Voltus, and HSC were asked to participate in a panel discussion to expand upon their experiences. The panelists were asked to identify the drivers behind LMR underperformance, possible solutions, and steps taken to solve the operational and communication issues experienced during PV19. Ultimately, this conversation culminated in the creation of the 2-19 Solutions document[6], which was created by Staff based on the panel discussion and input from other stakeholders. The panel discussion, as well as the numerous solutions identified in the document, are summarized below.

One of the primary contributors to LMR underperformance during PV19 was communication errors, either between the utility and customers or within the utility itself. In some instances, customers mistook the automated emergency notification for an economic buy through notification, which is a provision that allows the DR customer to pay a price instead of curtailing load. This caused them to ignore the signal to reduce load and continue operating as normal. Based on feedback from customers, this confusion seems to have stemmed from a lack of a sense of urgency in the automated messaging system, as the tone and voice of the emergency notification sounded similar to the economic notification.

In other instances, the customer did not receive a notification until much later in the event, causing the utility's portfolio to underperform. While the utility operators had received the LMR dispatch instructions from MISO, some customers did not receive the signal to reduce load until hours later, thereby missing a significant portion of the load reduction window. Some customers, however, were able to respond in full. Both HSC and GM were able to reduce loads to achieve the full nominated amount. While both companies did not expect a winter event, each attributed their successful response to training and preparation at their facilities as well as being able to communicate with their respective utilities in real time and over the course of the year.

[5] See Case No. U-20632 or more information on the workgroup here.
[6] Posted to website here.

Customer/DR program readiness and communication with the utility are the most important components of a successful response to a Max Gen event.

Taken together, these positive and negative experiences highlight the importance of clear, consistent messaging, so that customers are able to understand how to respond during economic and emergency conditions. Notification language and tone for an emergency event should sound and look different than economic notifications, in order to elicit the appropriate customer response. This communication should occur across a variety of platforms, such as automated message, telephone, and text in order to more easily reach customers while also taking into account the customer's preferred communication medium. Additionally, multiple personnel contacts for each customer site should be on file to reduce the number of unreachable sites. Since January 2019, utilities have made progress towards several of these items, including improving notification language, clarifying performance expectations, and considering new ways to notify customers of an event. In addition to appropriate messaging, the frequency of customer communication and education is a key component to ensure that the customer can respond when called upon.

Historically, LMRs have been rarely called upon by MISO because the need to do so has been infrequent[7]. However, LMRs are expected to respond in full when they are needed, often backed up by the threat of penalties for underperformance. As most customers are not heavily engaged in the energy industry, and primarily see participation in DR programs and tariffs as a way to lower their electric bill, frequent contact with their DR provider (the utility or DR service provider) is necessary to ensure their performance commitment in these rare events. In accordance with current utility practice, this contact should begin upon customer enrollment in a program and include follow up at least once per. Setting clear and consistent communication throughout a customer's participation in an interruptible rate will help ensure expected performance when an event is called. DR providers can partner with utilities to improve customer communications and performance, for example by creating customer-specific load reduction plans and automated event alerts. Several stakeholders stated that the customer's response improves with more frequent DR events, noting this is even more apparent for customers participating in multiple DR programs. However, frequent events can cause customer fatigue and attrition from DR programs. Currently, most Michigan utilities communicate with the customer at least once per year to review customer obligations, offer assistance, and develop load reduction plans as needed. More frequent interaction is preferable as Michigan's DR portfolio expands and DR is called upon more often throughout the region.

[7] January 30, 2019 was the first time MISO deployed LMRs in its North and Central regions in the history of its market. Slide 56

Another potential solution identified by stakeholders was the use of enabling technologies to assist with managing the utility's DR portfolio and easing the customer's response obligation. Before utilities can make full use of these technologies, they must have a core component, customer-specific metering. Today, most Michigan utilities have access to hourly metering through smart meters for residential customers and have access to real-time data for some commercial and industrial (C&I) customers. Several stakeholders commented that expanding real-time telemetry is the key to unlocking further DR potential, particularly as DR programs grow. Proponents of real-time metering suggest this is particularly important for C&I loads, but in their experience ideally 75% of DR customers should have real-time metering to enable the other technology options below. This added visibility would allow DR providers to directly monitor customer response and react to actual customer performance during emergency events. The benefits associated with real-time metering will continue to accrue as distributed energy resource (DER)[8] penetration increases across the state. Real-time telemetry is also a prerequisite for participation in ancillary services programs, which require access to data with at least 5-minute granularity. However, stakeholders also caution that the added benefits of expanded real-time metering should be weighed against its cost. With hourly data widely available throughout the state, the marginal benefit of real-time telemetry may not justify the additional cost for all loads.

Regardless of which metering interval is chosen, visibility into the customer's load is key to unlocking a variety of technologies. The technology most discussed during stakeholder meetings was a centralized DR platform designed to facilitate customer-DR provider communication, interaction, and reporting. To begin chronologically, a centralized software platform would automate many of the notification tasks that are required when a DR event begins. This would enable DR providers to notify customers within 5 minutes or less, if not immediately. As noted above, a quick notification turnaround from the RTO to the DR provider to a customer is essential to timely performance within the event window. As the DR event begins, the software platform would take customer data as inputs to evaluate individual and portfolio-wide performance in real time. This would allow utility operators to quickly identify and address underperformance at specific sites during a DR or emergency event. Ideally, the platform would allow both the customer and DR provider easy access to customer baselines and energy reduction plans already on file that operators could use to make personalized calls to customers and recommend actions in real time. This 'performance coaching' could quickly help to resolve performance issues in real time, helping customers and the DR provider avoid penalties. Lastly, a centralized platform could assist with post-event communication and reporting. The system could immediately send out a notification when the event has ended, allowing customers to get back online sooner and possibly avoid additional loss of production. Within a couple of days after the DR/emergency event has

[8] See NERC's 2018 definition of DERs, which does not include DR. Other entities, such as MISO, include DR as part of the broader DER definition.

ended, the system could generate preliminary performance reports which could be personalized and sent to each customer. These reports would help each customer understand how they performed and would add an additional level of transparency and communication to the process. Stakeholders mentioned such post-event reports are common and already exist today, including reports created by third party DR service providers and equipment manufacturers. To the extent that utilities do not already possess a robust centralized software platform with the above capabilities, third-party DR partnerships may be an efficient way to increase reliability, transparency, and customer interaction as some companies have already invested in and have developed their own platforms.[9] The utilization of a software platform can assist with multiple aspects of DR registration, deployment, and reporting, stacking the value delivered by such a tool.

Wholesale and Retail Alignment

Overview of Regional Transmission Operator (RTO) programs and recent rule changes

At the March 17th, 2020 stakeholder meeting, MISO and PJM were asked to provide an overview of each region's DR products, including how a DR resource's performance is measured and any recent rule changes, with an emphasis on those that have changed since January 2019. MISO explained that DR can be used in four distinct ways: as an economic, operating reserve, planning resource, or emergency only product. MISO has multiple DR registration options where qualifying resources can register as a Demand Response Resource (DRR), Load Modifying Resource (LMR), Emergency Demand Response (EDR), or dual-register in any combination of the above.[10] Upon registration, a MP has the ability to select how it would like its DR resource's performance to be evaluated. MISO's performance evaluation options are as follows: Firm Service Level (FSL), Meter Before/Meter After, Baseline Type-I, Baseline Type-II, and Metering Generator Output.[11] Each of these options has benefits and drawbacks which a MP must weigh based on the unique characteristics of each DR resource or program. For the purposes of this stakeholder group, the FSL and baseline approaches are the most relevant, especially as to how they incentivize customers to behave, as discussed in the Value of DR section below. As MISO explains, the FSL approach requires load to drop to a certain level, regardless of the current level of load. This is often referenced as the 'reduce to' approach. The baseline approach requires load to drop by a specific amount below the current load, the 'reduce by' approach. The MP can adjust how they would like their resource's performance to be measured on an annual basis.

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[9] See Ameren-Enel X partnership here, where Enel X's customer platform allows for real time monitoring and optimization. Voltus also has developed a similar platform, currently in use in Michigan and elsewhere.
[10] See March 17th materials, Slide 11, for a visual representation of all eight DR registration options.
[11] Ibid., Slide 12 for a detailed description.

MISO also compared how its market rules changed between January 2019 and Spring 2020. MISO's new notification and availability rules became effective February 21, 2019[12] and require documentation for resources with greater than or equal to six hours notification time or less than or equal to six months of availability. Documentation types include an attestation to the LMR's capabilities, a description of LMR operational characteristics, and regulatory/contractual limitations per MISO Business Practice Manual (BPM) 11, Section 4.2.8-4.2.9. These tariff and BPM requirements reduce the resource's notification time and increase the resource's availability, until reaching a notification time of two hours and availability of nine months, where no documentation is required.[13] Additionally, MPs must submit monthly availability in the MECT tool when creating registrations. These values become defaults in the MCS. These changes are intended to reflect a resource's true capabilities in order to give the operator more visibility and information when calling upon these resources. For example, if a resource is only available during the three summer months, those are the only three months when the MP inputs the data into the MECT. The Organization of MISO States (OMS)[14] and other MISO stakeholders were generally supportive of these changes. Recently, MISO has filed a proposal to further restrict these rules and is linked to the LMR accreditation filing discussed below.

The second set of market rules that changed between PV19 and Spring 2020 are MISO's new testing rules, which became effective June 1, 2019.[15] Previously, LMR testing was not a requirement to register as an LMR in MISO. Under the new tariff changes, testing is required for the full accredited amount of an LMR. Alternatively, the MP may opt of out testing, post $2400/MW in collateral and accept a three-times penalty in the event of non-performance, pending any regulatory restrictions on testing. This filing was submitted simultaneously with the LMR availability tariff filing above and is intended to allow MISO to more effectively assess the capabilities of LMRs they rely on to maintain the reliability of the grid. As with the availability ruleset above, the OMS[16] and other MISO stakeholders were generally supportive of both of these tariff changes.

Both the LMR availability and LMR testing tariff changes are part of MISO's ongoing, multi-phase Resource Availability and Need (RAN) initiative.[17] This initiative has continued into 2020, and has resulted in another rule change, this time to LMR accreditation, filed May 18, 2020 with the Federal Energy Regulatory Commission (FERC).[18] Under the proposal, starting in the 2023/24 Planning Year (PY 2023/24), LMRs would need to be able to respond within six hours or less to qualify as

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[12] See ER19-650, which was filed December 21, 2018.

[13] See March 17th materials, Slide 14-15 for a comparison of MISO's rulesets.

[14] OMS comments.

[15] See ER19-651, which was also filed December 21, 2018.

[16] OMS comments.

[17] More detail on the RAN initiative here.

[18] See ER20-1846.

an LMR, down from the twelve-hour notification time in the 2019 FERC tariff filing above. In addition, LMR capacity credit would be prorated based on the number of calls a resource is able to respond to in a given planning year. Ten or more calls will be required for 100% capacity credit and five to nine calls would receive 80% capacity credit. LMRs with availability less than five calls would not be eligible to receive capacity credit. Behind the Meter Generation (BTMG) resources registered as LMRs would continue to receive 100% capacity credit, provided they are able to meet the six-hour notification time and five to nine yearly call requirements. These BTMG resources will continue to be subject to further adjustment based on their outages and derates, making the capacity credit BTMG resources receive more aligned with the reliability value they are providing.

In response to MISO stakeholder feedback, these requirements will be phased in during the PY 2022/23, with some added flexibility for LMRs that cannot comply with the six-hour notification requirement. During PY 2022/23, LMRs with notification time greater than six hours, but less than twelve hours, will receive 50% capacity credit as long as they are available for a minimum of ten calls that year. Starting in PY 2023/24, all LMRs must meet the six-hour notification time in order to receive capacity credit. In conjunction with the 2019 LMR filings, MISO's accreditation proposal is intended to enhance the accessibility of LMRs during emergency conditions, improving flexibility and aligning LMR capacity credit with the services they can provide. While this accreditation proposal has not yet been accepted by the FERC, the OMS has filed supportive comments, particularly considering MISO's accommodation of a transition mechanism and additional leeway for LMRs that cannot respond within six hours or less.[19]

Primarily using the information in the Module E Capacity Tracking (MECT) Tool, MISO estimates that the LMR accreditation proposal will reduce Zone 7's (Michigan's lower peninsula) LMR capacity credit by 795 MW and Zone 2's (Michigan's upper peninsula + eastern Wisconsin) LMR capacity by 40 MW, assuming no action is taken by the MPSC or utilities.[20] For reference, Zone 7, which represents most of the lower peninsula of MI, currently has about 2200 MW of LMRs. Zone 2, which encompasses the Upper Peninsula and parts of Wisconsin, currently has about 360 MW of LMRs in the Upper Peninsula, exclusive of any LMRs in Wisconsin.[21] According to MISO, Zone 7's total impact is split between 285 MW of DR and 510 MW of BTMG resources.[22] In discussions with Michigan utilities, municipalities, and cooperatives, MPSC Staff has further broken down these estimates among the various entities. Consumers Energy estimates a 175 MW reduction and

[19] OMS comments here.
[20] See MISO's filing in ER20-1846, pg. 14.
[21] Per U-20590.
[22] See "MISO Estimate of LMR Accreditation Impact- Zone 7" table in Appendix

DTE estimates a 100 MW reduction[23] to their current LMR accreditation, per MISO's methodology. This leaves a remaining 520 MW impact in Zone 7, which will likely come from BTMG generators owned by non-MPSC regulated entities. Michigan Public Power Agency (MPPA) stated the six-hour lead time requirement would have a significant impact on several of their members' BTMG units, at least 130-150 MW as a verbal estimate on March 17th. From a cold start condition, the six-hour notification time would be difficult to meet without damaging the BTMG unit. Thus, MPPA highly supports a two to three-year transition to give its members time to make changes to their units. MPPA also suggested that disqualifying units above the six-hour notification time seems paradoxical to the goal of having more MW available to combat emergency event conditions. MISO's latest revision addresses some of these concerns, by adding an additional year of transition time for BTMG with above six hours, but under 12 hours lead time. Per MISO's description above, it is important to note that these estimates assume no change is made and consequently are expected to be well above the true impact. Pending FERC's acceptance of the filing, these entities will have until PY 2022/23 to make the necessary changes in order to continue to receive full capacity credit before this LMR accreditation tariff change is fully implemented in PY 2023/24. To comply with these MISO driven changes, Michigan utilities may need to update their MPSC jurisdictional DR tariffs accordingly, which could be done in conjunction with Staff's recommendations in the Tariff section below.

PJM was not as affected by PV19 and did not need to dip into emergency DR resources to meet load. While PJM did not experience the level of operational issues confronted by MISO, Staff asked PJM to provide an overview of their DR products, with an eye for any improvements made since PV19. Generally, the PJM footprint relies more heavily on Curtailment Service Providers (CSPs), DR service providers and/or utilities, who provide DR services to the customer. PJM's DR products are broken down into two categories: emergency and economic. Emergency, or load management DR, is able to participate in the energy and capacity market. Economic DR, like the MISO products, is able to participate in the energy and ancillary service markets when it is economic for those customers to do so. MPs can dual-register for any of the options above. PJM also offers two demand-side products, Price Responsive Demand (PRD) and Peak Shaving Adjustment (PSA), which allow load serving entities (LSEs) to reduce their capacity commitment. PJM offers two performance evaluation options; however, the vast majority of participants chose the FSL approach, the 'reduce to' method referred to above. PJM also offers a 'reduce by' approach, the Guaranteed Load Drop method, but this is rarely used. For each of these approaches, CSPs must submit 24 hours of actual hourly load data after a load management event occurs. PJM has not

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[23] See "LMR Accreditation Impact to DTE" table in Appendix. Also see Overview of utility programs section below.

made any DR tariff changes since PV19, with the exception of new load management testing requirements, filed April 12, 2020.[24]

Currently, if the resource is not dispatched during a Delivery Year, DR customers are required to perform an annual test of one hour for the entirety of the registered MW. The test is scheduled by the CSP with an unlimited ability to retest. As PJM notes, historically this has caused test performance to be greater than event performance. This test is not currently compensated and is subject to a nonperformance penalty of the revenue received by the underperforming MW, plus the higher of $20 or 20% of that revenue. PJM's new requirements are currently before FERC in a tariff filing and would require an annual test, scheduled by PJM, with a duration of two hours. Testing would be scheduled by each Transmission Owner zone, which would rotate monthly, ensuring DR resources would be tested across all seasons as the delivery years progress. If the DR resource can achieve greater than 75% of its registered MW in the initial test, the CSP may schedule an unlimited number of retests to improve their score. However, if a resource achieves under 75% during its initial test, a retest can only be scheduled with PJM during the same season to improve their score. With this more rigorous testing regime, CSPs would be paid for their energy reduction at the Locational Marginal Price (LMP) for the duration of the test event. PJM proposes an effective date of June 16, 2020, pending FERC's acceptance of the filing.

Overview of utility programs and response to changing RTO rules

During the March 17th, 2020 panel discussion, utilities were asked to provide an overview of their DR programs and any actions taken in response to the changing RTO rules above. CE reported that all of its DR programs are registered as LMRs, with the exception of Dynamic Peak Pricing (DPP). Since DPP is a hybrid program, where interruptions are combined with a time of use rate, CE reflects this load reduction in its load forecast, rather than an explicit registration at the RTO. LMRs provide CE with capacity credit and this registration is aligned with the program's use as an emergency-only resource. CE's residential programs are registered using a baseline performance evaluation methodology while most commercial and industrial programs use a targeted load reduction. The exception is C&I Rate GIQ, which uses a firm service level approach. With regards to LMR availability, CE will continue to provide documentation to MISO, recognizing that not all DR (like AC cycling) can be available year-round. Since PV19, CE has corrected the availability information input into the MCS, which was the primary driver for its underperformance. With regards to testing, CE indicated that it does not plan to require a real power test from their customers, and instead will provide historical information to MISO and attest to the performance capabilities of their DR portfolio. Per MISO's rules, CE can opt out of testing but would be subject to a three times penalty in the case of underperformance, which the utility accepts.

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[24] See ER20-1590.

With regards to LMR accreditation, C&I DR would be most impacted. CE expects a 175 MW reduction to its LMR capacity accreditation, assuming no changes are made. This reduction results from certain DR programs that are not able to meet the 10+ call limit. CE Rate GI does not currently specify a call limit and likely accounts for a portion of this impact. Rate GI's resource availability would simply need to be updated in the MCS. CE enters into contracts with these customers, most of which are multi-year contracts that are up to four years in length. CE negotiates these contracts based on the current MISO tariffs to ensure that the required interruptions specified by the contract are aligned with the current tariff and do not require the customer to be available for ten or more calls per year. CE would be able to renegotiate these contracts going forward but could lose about 118 MW of capacity credit for their contracts if MISO's tariff change were effective immediately for the planning year 2021/22. To mitigate the impact of MISO's tariff changes on its C&I DR program, CE has advocated for a three-year transition time, which would give the utility time to make the necessary changes and renegotiate its contracts.[25] CE does not expect to be impacted by the six-hour lead time rule change.

Similar to CE, all of DTE's programs are registered as LMRs with the exception of retail rate tariff DPP. DTE is considering shortening the notification time of their DPP rate in order for the rate to qualify for capacity credit at MISO. This change may occur by the 2022 capacity auction, pending testing and customer reactions. Rider 12, which pays C&I customers for their interruptible capacity, was marketed in 2019 to customers. DTE registered this rate as an LMR at MISO in 2020. With regards to LMR availability, DTE is again positioned similar to CE. DTE will continue to provide documentation to MISO, recognizing not all DR programs will be available year-round, and will continue to update the MCS with hourly availability. With regards to testing, DTE would only require real power testing for Direct Load Control customers. While still weighing the benefit/cost, DTE would likely opt out of the testing requirement and accept the increased penalty for nonperformance. DTE expects no impact to its registered LMR due to changes in DR accreditation by the time MISO's new tariffs go into effect. The 100 MW estimated impact in MISO's methodology is accounted for in DTE's DR registrations, which can and will be updated annually. Most of DTE's remaining programs do not have call limits[26] and the utility does not expect any issues with the requirement of more call times. DTE supports the MISO proposal and is not opposed to a transition time.

Indiana Michigan Power Company (I&M) has 135 customer accounts footprint wide, representing 82 MW, registered at PJM as an emergency resource. I&M also offers a C&I customer specific interruptible program, which is not registered at PJM. The vast majority of I&M's DR customers use the firm service level performance methodology as described above. With regards to DR

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[25] See Consumers ER20-1846 Comments.

[26] The Bring Your Own Device and Smart Currents programs currently have a call limit of 10, which earn them full capacity credit under the new MISO methodology.

availability, I&M noted that there are three different lead time options for PJM emergency DR: 30, 60, or 120 minutes. These programs provide the customer with more options, and I&M has no concerns with this approach. With regards to testing, I&M is already required to perform an annual real power test, per PJM's rules. I&M is supportive of PJM's new testing proposal, as they seem reasonable and better mimic actual availability during a DR emergency event.

Testing

As referenced in the Wholesale/Retail Alignment section above, MISO's tariffs regarding testing changed June 1, 2019 to require a real power test or accept a higher penalty in the case of nonperformance.[27] During panel discussions at the February and March 2020 meetings, stakeholders were asked about the merits of requiring a real power test or opting out in favor of a heightened nonperformance penalty.

CE stated it would not require a real power test and would instead provide historical information to MISO to attest to LMR performance capabilities. However, CE noted customers do have the option to conduct a 30-minute dispatch readiness test to help them prepare for an event. CE would simulate a DR event and monitor the customer's performance, giving the customer valuable feedback in a real-world setting. Should the customer fail to achieve at least 70% of their registered MW, CE would follow-up after the event to better understand any performance issues and potentially update the energy reduction plan on file. To the latter point, before signing up a customer on a DR program, Consumers creates an energy reduction plan for each specific customer. The plan includes the MW reduction nominated, type of affected equipment, shutdown procedure, and load reduction for each piece of equipment. CE uses this information to assess whether the stated reduction is viable and works with the customer before signing them up on the rate.

DTE had a similar response to CE and only expects to perform real power tests for its Direct Load Control customers. For the remainder of their LMR customers, DTE is currently analyzing the costs/benefits of requiring a real power test. DTE polled its interruptible customers to gauge the impact of a real power test and whether that would impact their decision to remain on the rate. DTE's initial finding suggest that the cost and inconvenience of testing would be high. Consequently, the utility is leaning towards accepting the increased nonperformance penalty, while continuing to provide all necessary documentation to MISO. DTE also noted its annual LMR readiness process helps ensure all interruptible customers are aware of their obligations and notification process if a DR emergency event is called. DTE annually sends out reminders via letter, notifies customers of any test date if applicable, and verifies contact information ahead of the summer season.

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[27] See ER19-651, which was filed December 21, 2018.

Voltus, a DR service provider, pointed out that most other RTOs, including PJM, IESO, CAISO and ERCOT, already require an annual real power test and that MISO is an outlier in this space. When Voltus tests their own customers, it works with the customer to perform the test in the least disruptive manner possible. Voltus notes that if testing is required, it should also be properly valued, whether that be through a capacity market payment or a line item for testing. In the absence of compensation, testing can be quite onerous for some customers, leading them to rethink their level of commitment or to simply not participate.

The Foundry Association of Michigan reported that real power testing would be very deleterious to its members. Testing, would mean an interruption in heavy industrial processes, leading to an economic loss in the form of loss of product at a minimum or possible equipment damage. Depending on the situation, this loss could be substantial, up to tens of thousands of dollars. Compensation for testing, outside of a reduced rate, would likely not be enough to cover these costs. Instead, the Foundry Association indicated its willingness to participate in a tabletop exercise to demonstrate its facilities' ability to drop load in emergency conditions.

Hemlock Semiconductor (HSC) echoed the Foundry Association's thoughts above. HSC was able to fully perform during PV19, when testing was not required, due to robust operating procedures and documented simulations. HSC suggests that these could be submitted in lieu of a real power test. If a real power test would be required, HSC would prefer to be able to test a portion of its load, instead of the full registered amount. HSC explained that in addition to losses incurred during the test, their facility would take several days to ramp back up to full production after an event. This would compound the economic losses and make testing compensation inadequate.

Entities in PJM, like I&M, are already required to conduct an annual real power test for their emergency DR resources. PJM has attempted to strike a balance between performance and customer compensation by paying participants based on the LMP for the testing hours. While this option has not been pursued at MISO, stakeholders have suggested that compensation for testing should be evaluated on a program-by-program basis if attempts were made to compensate at the retail level.

In summary, most stakeholders prefer simulation only, in lieu of a real power test. Most also agree that specific compensation for testing would likely be inadequate to cover costs. Instead, testing, if required, should be properly valued by the capacity market or retail rate.

DR Value Streams

Economic vs. Emergency Resource

An underlying theme throughout these stakeholder meetings was the need to investigate ways to maximize the value of DR, particularly as an emergency resource, but also as an economic resource where appropriate. While most of the value currently comes from the capacity construct, particularly in MISO, DR is also able to participate as an economic resource, via the energy and ancillary markets. Voltus, which has a footprint across the United States, noted the importance of value stacking, as seen in other markets. DR providers are able to combine the traditional capacity value of DR with other RTO products, as well as peak shaving on the customer level. A diversity of program offerings at the retail level could facilitate this value stacking and open the door to dual-registration at the RTO level.

However, as the utilities noted, different program options have been offered in the past, but customer interest was lacking. CE stated that its C&I contractual program did offer an economic option for several years. However, customers did not opt-in to the program at high enough levels to move it out of the pilot stage. HSC described its struggle to see how it could operate with stacking emergency and economic events. Clarity around how these events would interact, and which would take priority is needed for HSC to explore dual-registration further. DTE is also testing the concept of offering an economic option via Rider 12. While in the initial stages, DTE's concern is that economic events are called more often, which may lead to greater levels of customer attrition. This impact appears to be less for residential customers. DTE can currently dispatch these customers for economic reasons under its air conditioning (AC) cycling programs as well as the general service interruptible tariff (D3.3). CE, DTE, and I&M are open to exploring value stacking further and indicate that this may be best completed via the pilot program process.

The American Council for an Energy-Efficient Economy (ACEEE) noted that the industry has recognized the possible synergies from coordinating the deployment of technologies that reduce energy use (kWh) and peak demand (kW). Demand Response programs could be designed to be integrated with appropriate Energy Waste Reduction (EWR) programs, so that customers are fully aware of their options, and so that optimal energy solutions for the customer and the electric system can be fully considered.

In conclusion, DR programs must provide value to both the utility and customer. Enticing customers to sign up for multiple DR programs will require an additional level of marketing and communication, in order to ensure the customer understands each program, any interactions, and what value dual-enrollment would provide to the customer. As the need for grid flexibility grows, the value of DR will increase for both utilities and customers.

Performance Obligations and Unintended Incentive

The panel discussions on February 19th and March 17th included the idea of a potentially unintended incentive embedded in some DR registrations. The applicability of this incentive is largely dependent on how a DR resource's performance obligation is measured.[28] Upon registering the resource at the RTO, the DR provider can choose which measurement and verification (M&V) protocol the resource will be subject to. Most M&V protocols can be classified into two buckets: a 'reduce by' (targeted reduction) or 'reduce to' (firm service level approach).

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[28] See March 17th materials and above for a description of each of the performance evaluation methods.

Under the 'reduce by' approach, a customer has the incentive to increase or maintain load just before an event, thereby allowing for the customer to meet its MW reduction target more easily. If deployed en masse, this incentive may not align with the needs of the system during an emergency event, where less energy consumption overall may better ease system conditions. Stakeholders noted that if a 'reduce to' approach was used instead, the customer would be able to ramp down earlier and more gradually, perhaps also allowing the customer to extend the duration of the reduction. This option may grant additional flexibility to customers who favor a slower ramp down to avoid damage to their equipment. Other stakeholders cautioned against mandating one approach over the other. Each performance methodology has pros and cons or may be suitable for difference resource/load types, so stakeholders suggested studying a small group of customers to understand any unintended consequences before making further changes.

In order to facilitate DR participation, it can be important to give DR customers the flexibility to select DR performance measurement approaches that best suit their operational requirements. This can be achieved with the customers being able to select the Guaranteed Load Drop of the Firm Service Level option for measuring DR performance.

DR Aggregation

While DR aggregation was the focus of Case No. U-20348 and the 2019 stakeholder group,[29] the outcome of that proceeding and ongoing action items are relevant to the Commission's overarching reliability and resilience goals in Case No. U-20628. Thus, Staff reviewed the outcomes of U-20348 that provided an overview of MPSC processes related to DR aggregation. The proceeding also coordinated informational updates from MISO, the Advanced Energy Management Alliance (AEMA), Michigan utilities, and the National Regulatory Research Institute (NRRI).

To start the discussion, Staff provided an overview of the capacity demonstration process, focusing on how aggregated DR is represented. Currently, aggregated DR represents about 71.4 MW in Michigan as evidenced by the 2020 capacity demonstration filings. Staff noted that as participation in aggregated DR increases, the need for communication between the MPSC, the incumbent utility, the Alternative Electric Supplier (AES), and the DR service provider becomes increasingly more important. This particularly holds true for any DR dispatched on MISO's peak, which has the potential to change a customer's Peak Load Contribution (PLC) and must be properly accounted for in MISO and MPSC planning processes.[30]

Pursuant to the Commission's direction in U-20348, Staff continues to advocate for changes to address this PLC issue at MISO,[31] primarily focusing on information flow and data sharing.

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[29] More information here.

[30] See the 2019 DR Aggregation Staff Report for a full description of this issue.

[31] See MPSC feedback to MISO's Markets Subcommittee here, here, and here.

Recognizing feedback from the MPSC and other Michigan stakeholders, MISO has proposed changes to Module E-1[32] that would facilitate needed information exchange when aggregated DR is dispatched on MISO's peak. Staff is supportive of these changes and expects them to mitigate the PLC issue above. In addition, the MPSC remains able to request this information from MISO, subject to all relevant confidentiality agreements. However, discussion at the April 28th, 2020 meeting revealed that while the AES should have access to this DR dispatch information under MISO's current tariff, or at least be able to infer this data through their own metering information, the AES may not have access to this information in practice. Staff plans to investigate this matter in future discussions with MISO, the utilities, and AESs and clarify the duties of each entity.

Another key outcome of U-20348 included a focus on utilities, encouraging them to leverage relationships with DR service providers which will further expand DR opportunities and/or identify options for scaling up of DR aggregation. These utility-DR service provider partnerships could come in the form of a full turn-key solution, where DR service providers acquire and manage DR customers on behalf of the utility, or a limited contractual arrangement where the utility is able to make use of a third party's enabling technology or software platforms to help manage the utility's DR portfolio. AEMA, whose members include DR service providers, suggested that DR providers should have three key capabilities that are essential to DR program reliability and success: 1) sufficient metering to provide visibility into customer load (75% of portfolio to effectively manage the portfolio), 2) robust customer readiness procedures, and 3) a centralized portal that allows utilities to analyze, monitor and coach customer performance during events.[33] To the extent that utilities do not already possess these capabilities, partnering with a third-party provider may be an efficient use of ratepayer dollars as compared to developing such assets in-house. To facilitate these partnerships, AEMA suggested that the MPSC could provide additional direction to better align spending with the MPSC priorities stated in Case No. U-20348. To this end, the MPSC could direct utilities to incorporate the above capabilities into their DR programs, taking advantage of existing third-party provider capabilities as necessary and prudent.

Staff invited CE, DTE, and I&M to provide an update on any DR provider partnerships and how the utilities plan to build these partnerships in the future. CE and DTE do not make use of full turn-key solutions with DR service providers. Rather, the utilities partner with third parties as service providers to assist with monitoring, customer portals, or other technologies. CE reported that they currently use third parties to assist with real-time monitoring as well as to run the customer portal. Both of these functions work in unison to provide data to the customer dashboard and enable the

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[32] Proposed Module E-1 changes here. The proposed language would require MISO to provide the Electric Distribution Company (EDC) the amount of measured load reduction that occurred as a result of a DR service provider deploying demand response during the MISO coincident peak.

[33] See LMR Operation and Communications section above or April 28th meeting materials for more detail on these points.

utility to respond in real time. CE expects to continue to explore DR partnerships in the future and sees the pilot process as particularly helpful in this regard as it gives the utility the flexibility to explore new opportunities outside of the typical rate case process. DTE currently uses DR partnerships to manage its Bring Your Own Device (BYOD) and SmartCurrents programs. DTE's partners with the service providers for services such as, but not limited to, marketing and platform support, which allows DTE to take advantage of external expertise in those areas. Apart from the Load Watch[34] program for C&I customers, DTE relies on post-event AMI meter data to assess how customers were able to respond to DR events. DTE is open to future DR partnerships, as directed by U-20348, but notes that its plans were delayed by the current COVID-19 crisis. I&M and its parent company, AEP, has experience working with DR service providers across several states and recently has established its first CSP partnership in Michigan. I&M will continue to work with PJM, the MPSC, and the CSP to define the partnership and its framework as DR aggregation expands in the Michigan footprint.

NRRI also spoke on actions that states have taken on DR in recent years, including DR aggregation. Several states offer pathways for non-utility providers to offer DR services. Learnings from other states indicate various levels of successes and impediments, including an increased level of DR and supporting technologies, but all have concluded that there is a greater need for data sharing and coordination. In the future, NRRI hypothesized that the incumbent utility's role and business models could change based on how DR, and other services, are structured within a particular state. Options range from an open access system, where third parties design and offer products to meet customer needs, to a system similar to today, where the utility manages program offerings and opportunities. NRRI will be exploring this and other DR policy questions as part of an upcoming paper.

Utility Demand Response Tariffs

As directed by the MPSC's Order in U-20628, Staff conducted a review of all Michigan interruptible utility tariffs, looking for areas for improvement or alignment in coordination with the ongoing stakeholder process. As highlighted during the February and March 2020 stakeholder meetings, Staff found four possible areas for improvement which are: consistency, transparency, specificity, and testing.

Broadly speaking, interruptible tariffs follow a similar arrangement across utilities. Each tariff includes information about what customers can participate, notification procedures, the penalties for non-interruption, the discount for participation on the rate, a definition of firm load, and the contract term length. Additional components that may be offered through interruptible tariffs include options to "buy-through" events, product protection fees, change interruptible load mid-season, and a variety of pricing options. In addition to tariffs approved by the Commission, utilities

[34] Load Watch is DTE's proprietary software which enables large C&I customers to access real-time usage.

also offer interruptible DR programs that are negotiated between the utility and customer through contracts (e.g. CE's C&I DR Program). These contract-based programs offer the greatest flexibility by allowing the utility and customer to agree on the exact terms of their participation in DR. However, some utility tariffs do not mention these contract-based DR programs. To enhance the transparency of utility DR offerings, utilities should be required to have a tariff sheet approved by the Commission that provides information regarding all of the DR programs that they provide within their respective service areas, including contract-based programs. The DR program information provided in the utility tariffs should not be restricted to the standard interruptible rates that the utilities offer.

The workgroup expressed interest in offering a diverse set of DR programs to customers. Options include various pricing, seasonal or year-round interruptible service, variable contract lengths, and the addition of energy and ancillary services on top of capacity programs. Being too prescriptive in areas of the tariff may hinder the participation of customers with heterogeneous load profiles or end-uses.

While variety in some specific aspects of interruptible tariffs is useful to customize a utility's offerings to its unique service territory, consistency across certain provisions could be beneficial to the customer. Penalties, or what the customer is charged for failure to interrupt during an event, should not vary between utilities in the same RTO because non-interruption does not carry a different cost depending on service territory. Because the call for emergency interruption ultimately comes from MISO or PJM, the penalty should be the same for all customers in the same RTO zone. Likewise, penalties for non-interruption should remain consistent across rates within the same utility, provided these rates are associated with the same RTO product (LMR, EDR, DRR, etc.). The interruption start window, or how long the customer has until it must reduce load following a call from the utility, should also be consistent across utilities. This way, an interruptible customer being served by different utilities at different business locations would have the same expectations of interruption during an emergency event.

The notification process should be completely transparent for all interruptible tariffs. When notification procedures are formalized the interruptible tariffs can provide greater clarity for the customer and expectations for the utility. A formal notification detailed in a tariff also gives the customer some redress if a utility fails to properly notify the customer of an event. Notification procedures in tariffs should also include specific expectations for customer response during economic versus emergency events, such as whether or not a customer can buy-through an event. Customers should be given the opportunity to express their preference for communication medium for notifications to ensure a timely response to events. For contract-based interruptible programs, the notification procedures should also be clearly defined for the customer.

Testing procedures could also be included in the interruptible tariffs. By listing the testing procedures in the tariff, the risk to ratepayers is reduced because there would be assurance that the resource they ultimately pay for is available. This would also provide assurance for the utility, who is responsible for the load reduction at MISO. Further, including testing procedures in interruptible tariffs ensures that the standard to which the DR resource is tested will not change year-to-year. Real power testing versus simulation is still up for debate because there is significant cost to the customer if actual load shedding must occur for testing purposes. Testing should be required annually at a minimum.

Modifying existing interruptible tariffs to conform with the recommendations provided in this report may take place in two types of proceedings before the Commission. First, changes to tariffs, including new interruptible program offerings, that affect the cost to serve customers typically occur in general rate cases by evaluating the costs and benefits of the program through the cost of service study and the impact on customer rates when viewed holistically with the other myriad changes and adjustments that occur in such cases. This venue also provides a formal and open forum for affected customers, Staff, and the utility to contest any proposed changes to interruptible tariffs. However, a general rate case proceeding can take up to 10 months and involves significant resources for normal quasi-judicial activities like discovery, expert testimony, and multiple hearings. A general rate case is most appropriate for numerous or significant alterations to interruptible tariffs.

Second, interruptible tariffs may also be updated or experimental/pilot DR programs can be filed through ex-parte cases before the Commission. In order for these cases to proceed, the proposed changes to the tariff cannot change the cost for any other customer. In this type of case "ex-parte" means "without party," which means that there are no other parties to the case besides the applicant and the Commission. The applicant, typically the utility, will file a revision to its tariff that is applicable to, its justification. The application may include an affidavit with supporting arguments. Staff experts review the ex-parte case application and submit its analysis to the Commission. The Commission can then approve, deny, or approve with modification. These proceedings are most appropriate for minor changes to tariff language, but can also be used to update tariffs for some of the recommendations made in this report. For example, the formalization of DR event notification would not cause the cost of service for any customer to increase, supposing the utility already has the infrastructure in place. Of course, a proceeding may begin as ex-parte, but the Commission or applicant may invite stakeholders to comment.

Recommendations

After hearing from various stakeholders and participants across four meetings, Staff has developed the following recommendations as directed by the Commission in U-20628. These recommendations were developed with significant input from Stakeholders and were initially outlined in the February 19th Solutions document.[35] Staff acknowledges that utilities, RTOs, and DR customers have already made improvements since PV19, and consequently offer several

[35] Solutions document here.

steps that build on this foundation. Per Commission direction in U-20628, Staff believes that the enhancements below will continue to improve LMR performance, enhance communication procedures, and augment reliability as DR expands throughout the state. Reasoning for these items are outlined below and found throughout the body of the report above.

I. Ensure LMR availability is properly accounted for in MISO's MCS tool

The primary contributor to Michigan's underperformance during PV19 was a failure to enter the proper availability into the MCS tool. In several cases, the utility marked DR customers as available in the MCS, when, in reality, those customers were not required, by contract, to respond outside of the summer. Resource availability should be accurately represented in the MCS to avoid this issue in the future. Staff recognizes that MISO tariff revisions and changes to utility procedures since January 2019 have largely addressed this issue and advocate for full compliance with the relevant provisions of the MISO tariff. With ongoing MISO rules changes, including LMR accreditation, LSEs should also ensure that the information in the MECT is updated as changes are made.

Stakeholders have expressed concerns regarding the suitability of relying on DR availability data in the MCS for the purpose of establishing the capacity accreditation of DR resources. MISO is planning to undertake a stakeholder process to evaluate potential changes to the MCS reporting requirements for DRs.

II. Ensure clarity and consistency in communication processes

A lesser contributor to Michigan's underperformance during PV19 was too delayed or imprecise communication by the utility and confusion among the customers. DR notifications from the RTO should be processed in a timely manner and sent out to the customer as soon as possible, ideally within five minutes or less. Utility operators should recognize and train themselves on the various ways RTO notifications reach the operations center, in order to relay these instructions quickly and accurately to their account managers and customers. In addition, the utility emergency notification to reduce load should sound and look different than an economic notification, to order to elicit the appropriate customer response. This communication could occur across a variety of platforms, such as e-mail, telephone, and text, allowing for utilities to more easily and dependably reach customers. Additionally, multiple personnel contacts for each customer site should be on file to reduce the number of unreachable sites, and at a minimum be reviewed annually.

III. Increase DR provider interaction with the customer

Historically, emergency DR has rarely been called upon, but is expected to perform in full when dispatched. Currently, most Michigan utilities communicate with the customer at least once annually to review customer obligations, offer assistance, and develop load reduction plans as needed. More frequent interaction may be preferable as Michigan's DR portfolio expands and DR is called upon more often throughout the MISO region. Biannual or quarterly contact, particularly for non-direct load control customers, would help strengthen the DR provider-customer relationship, offer an opportunity to alleviate any concerns, and set expectations ahead of each season. More frequent contact could be assessed on a case-by-case basis, particularly for those customers who are participating in more than one program.

IV. Explore the use of enabling technologies where feasible and cost effective

Enabling technology, ranging from customer-owned devices to automated systems put in place by the utility, can help ease the customer's response obligation, provide visibility into DR deployment, and enable more sophisticated management of a provider's DR portfolio. Before such technologies can be widely adopted, the DR provider must have visibility into customer loads in real time, or as close to real time as is cost-effective. With hourly AMI meter data available throughout most of the state, as well as real-time meters for some C&I customers, Michigan is well situated to make use of other technologies, should they prove to be cost effective in cases before the Commission. While real-time metering for the majority of customers may be preferred, this is unlikely to be cost effective. Thus, DR providers should be directed to make full use of the existing infrastructure and make the case for new technology as it develops. Technologies such as automatic controls, automatic notification systems, and software platforms are key to some of the recommendations in this report and would continue to provide value as DR grows throughout the state. In particular, the utilization of a software platform can assist with multiple aspects of DR registration, deployment, and reporting, stacking the value delivered by such a tool. With increased visibility into DR dispatch and real-time issues, such technologies could further enable DR value stacking by making it easier for the DR provider to manage customers enrolled in multiple programs, potentially increasing the value each MW could provide. In addition, any technologies adopted for DR purposes would likely prove useful in the future as DERs, including storage, expand in Michigan.

V. Direct utilities to explore DR partnerships for real-time metering, customer readiness, and a centralized platform

Per U-20348, utilities were encouraged to explore DR partnerships with DR service providers to take advantage of expertise and existing capabilities. As shown above, real-time metering, customer readiness and a robust software platform are key to building a successful and responsive DR portfolio. To the extent that utilities do not already possess these capabilities, partnering with a third-party provider may be an efficient use of ratepayer dollars as compared to developing such assets in-house. While utilities may have already developed some of these aspects above, partnerships could add valuable improvements to reliability and the utility-customer interface. This holds particularly true if the utility gains access to a centralized software platform, which would interact with each of the recommendations listed above. Ideally, a robust, user-friendly platform would help with customer registrations and load reduction planning, streamline communications, enable real-time coaching, and quickly provide after-the-fact performance reports directly to the customer. A partnership could be leveraged by the utility to better manage its DR portfolio and more easily interact with the DR customer.

VI. Require an annual documented simulation and encourage real power testing where feasible

While real power testing may be the preferred method to ensure reliability under true emergency conditions, the MPSC Staff recognizes the impact such a test may have on the customer's operations. Rigorous simulations, documented for the benefit of the customer, utility, and RTO, may provide a reasonable substitute for a real power test. Simulations should reproduce emergency conditions, enable the customer to walk through each step of the emergency procedures, and provide an opportunity for after the fact learnings. If approached in this manner, simulations balance the reliability need of the system with the economic impact of a real power test. However, the severity of such economic impacts differs across customer classes and even individual customer sites. For example, heavy manufacturing and industrial processes incur a greater power interruption cost than a residential AC system. To the extent practicable, DR providers should be encouraged to perform a real power test where it is cost effective to do so. This could include testing only a portion of the customer's accredited load reduction, which may provide valuable insight into the reliability of the resource while minimizing the impact to the customer. For added flexibility, the tariff could give the customer the opportunity to request a real power test if, for example, the customer expects its operations to already be interrupted for other reasons. Utilities should be directed to list testing requirements in their retail tariffs, which would enhance accountability for ratepayers, who will be assured that the resource they pay for is available, and for the utility, who is ultimately responsible for the load reduction at MISO.

VII. Formalize and standardize the notification procedure and penalties in utility tariffs

A formalized notification procedure will provide greater clarity for the customer and would set expectations before an event occurs. As discussed in Recommendation II, these procedures should include specific expectations for emergency versus economic events and give customers the opportunity to express their preference of notification method, whether that be via text, phone call, etc. A customer's preference should not preclude the utility from using multiple communication avenues during events. In addition, Staff recommends that the notification response window, how long the customer has until it must reduce load following a call from the utility, be made consistent across utilities depending on the registered resource type with the RTO. This way, an interruptible customer being served by different utilities at different locations would have the same expectations of interruption during an emergency event.

Staff also recommends that penalties should be made consistent between utilities, because non-interruption does not carry a different cost depending on service territory. Since the call for emergency interruption ultimately comes from MISO, the penalty should be the same for all customers in the same MISO zone. Likewise, penalties for non-interruption should remain consistent across rates within the same utility.

VIII. Any necessary tariff changes should be made in a general rate case or an ex parte case

Changes to tariffs that affect the cost to serve customers should occur in general rate cases, where the costs and benefits of the program can be incorporated into the cost of service study and customer rates at the same time as the other myriad changes and adjustments that occur in such cases. However, since a rate case can take up to 10 months, a general rate case is most appropriate for numerous or significant alterations to interruptible tariffs. In instances where tariff changes do not change the cost for any other customer, Staff recommends that these changes occur in an ex-parte case. The ex-parte format lends itself well to minor changes and updates to tariffs, such as those linked to several of the recommendations in this report. The Commission remains free to invite stakeholders to comment on ex-parte proceedings.

IX. Enable DR value stacking: capacity + energy + ancillary services

As the need for grid flexibility grows throughout the industry, DR's ability to provide multiple services will be increasingly valuable and should be encouraged wherever possible. Dual-registration options already exist at MISO and PJM, which should be matched by diverse program offerings at the retail level. Staff recommends that testing of dual-registration options, particularly the economic or ancillary component of DR, occur through the pilot program process. To the extent that customer interest in dual-registration seems lacking, enhanced marketing strategies, increased customer education, learnings from DR service provider experiences in Michigan and learnings from outside Michigan should be used to augment utilities' efforts to engage its customer base. It is also through this process that the DR provider could test various M&V options, to match the utilities' needs while giving customers flexibility as to how their performance will be measured.

Conclusion

Throughout the four meetings Staff hosted, the utilities, RTOs and customers were provided with the opportunity to share experiences and lessons learned from PV19. The utilities presented on steps they have taken since January 2019 to improve future emergency DR events, and stakeholders discussed areas still in need of further analysis and/or improvement. The recommendations Staff makes above attempt to capture the invaluable feedback provided during this endeavor and improve the future of DR emergency events, as well as pave a path for additional DR program options to expand and refine Michigan's DR portfolio.

Interested stakeholders were presented with significant opportunity for participation through listserv messages, stakeholder meetings, and written feedback. Staff has reviewed and taken into consideration the proposed changes to the draft Staff report outline and has included in the

Appendices the finalized comments of those stakeholders who requested that they be attached to the final report.

Appendices

MISO Estimate of LMR Accreditation impact- Zone 7

Resource Type	Potential LRZ 7 LMR Accreditation Impacts for 2021 PRA (MW)
BTMG	510
DR	285
Total	795

LMR Accreditation Impact to DTE

CP	Resource Name	Lead-Times	# of calls	Type	ICAP	After reduction
DECO	DR Water Heaters	1	5	DR	5.0	4.0
DECO	DR Int. Air. Conditioning	1	12	DR	143.0	143.0
DECO	DR Other Programs	2	5	DR	494.9	395.9
DECO	BTMG Resource 1	1	12	BTMG	0.6	0.6
DECO	BTMG Resource 2	1	12	BTMG	14.4	14.4
DECO	BTMG Resource 3	1	12	BTMG	0.2	0.2
DECO	BTMG Resource 4	1	12	BTMG	11.0	11.0
DECO	BTMG Resource 5	1	5	BTMG	2.9	2.9
DECO	BTMG Resource 6	1	12	BTMG	0.4	0.4
DECO	BTMG Resource 7	1	12	BTMG	0.2	0.2
DECO	BTMG Resource 8	1	5	BTMG	42.8	42.8
DECO	BTMG Resource 9	2	5	BTMG	0.7	0.7
DECO	BTMG Resource 10	1	12	BTMG	8.1	8.1
DECO	BTMG Resource 11	2	5	BTMG	2.6	2.6
DECO	BTMG Resource 12	1	12	BTMG	4.8	4.8
DECO	BTMG Resource 13	1	5	BTMG	2.9	2.9
	Total				**734.5**	**634.5**

Michigan Interruptible Tariff Comparison
MI Power Grid Demand Response Workgroup

Utility	Rate	Min. Load Per Customer (kW)	Economic	Emergency	Emergency Penalty ($ per kW)	Emergency Penalty Applied To	Buy Through Fee ($ per kWh)	On-Peak Demand Discount	On-Peak Energy Discount	Who Interrupts?	After Notification Must Interrupt within	Season	Max Annual Interruption Hours	Contract Length (years)	Notification
Consumers	GPD-GI Interruptible Service Provision	500	No	Yes	$ 25	15 minutes		$ 7.00		Customer	30 minutes	Year round	N/A	1	30 minutes
Consumers	GPD-GI 2 Market Price Provision	3,000	No	Yes	$ 25	15 minutes			LMP	Customer	30 minutes	Year round	N/A	1	30 minutes
Consumers	Business DR		Yes	Yes	Per contract	Per contract	Per contract	Per contract	Per contract	Customer	Per contract	Summer	Per contract	Per contract	Per contract
DTE	D3.3 Interruptible General Service		Yes	Yes	$ 50	*30 minutes*			$ 0.01906	Company	1 hour	Year round	N/A	Open	None
DTE	D8 Interruptible Supply	50	Yes	Yes	$ 50	30 minutes	$0.00576	$ 7.63		Customer	1 hour	Year round	N/A	5	ASAP
DTE	R10 Interruptible Supply Rider	50,000	No	Yes	$50 per kW	*contract capacity*			LMP	Customer or Company	10 minutes	Year round	N/A	2	Minimum 10 minutes
DTE	R12 Capacity Release	100	No	Yes	$ 50		Per contract	Per contract	Per contract	Customer	Per contract	Summer	Per contract	Per contract	ASAP
I&M	Contract Service-Interruptible Power	1,000	Yes	Yes	Per contract	Per contract	Per contract			Customer	Per contract	Year round	Per contract	Per contract	Per contract
UMERC	Experimental Curtailable Rate Cg3C		Yes	Yes	$ 15		10%		$ 0.02020	Customer	1 hour	Year round	300	1	1 hour
UMERC	General Primary Interruptible Rate Cp2	1,000	No	Yes	$ 35	15 minutes		$ 2.89		Customer		Year round	150	5	
UMERC	General Primary Curtailable Rate Cp3	500	Yes	Yes	$ 15		10%		$ 0.01950	Customer	1 hour	Year round	300	1	1 hour
UMERC	General Primary Large Curtailable Contract Rate CpLC	50,000			$ 35						2 hours		300	1	
Alpena Power	Large Industrial Service				$ 50	1 hour	$ 0.01	$ 2.50			1 hour			2	
NSP	Peak Controlled Time of Day Service MPC-1	50	Yes	Yes	$ 13.80			3.34		Company or Customer		Year round	80	5	endeavor for 1 hour
NSP	Peak Controlled Time of Day Service MPC-2	50	Yes	Yes	$ 13.80			4.46		Company or Customer		Year round	150	5	endeavor for 1 hour
UPPCo	Commercial Power-Interruptible Rider		Yes	Yes	$ 90	15 minutes	10%			Customer	1 hour		600	5	endeavor for 1 hour

CLARK HILL

MEMORANDUM

TO: Katie Smith and Erik Hanser – MPSC Staff

FROM: Bryan Brandenburg – ABATE Counsel

DATE: July 17, 2020

MATTER: MI Power Grid Demand Response Workgroup (U-20628)

SUBJECT: ABATE's Comments Regarding Staff's Draft Demand Response Report

The Association of Businesses Advocating Tariff Equity ("ABATE"), by its attorneys, Clark Hill PLC, hereby provides its Comments in response to the Michigan Public Service Commission Staff's ("Staff") July 1, 2020 draft demand response ("DR") report ("Report").[1] While these Comments do not address every DR issue discussed in the draft Report, ABATE's lack of commentary on a particular issue does not necessarily indicate agreement with Staff's discussion of such issue and ABATE reserves the right to remark on said issues in the future. ABATE primarily focuses its Comments on certain DR implementation issues and policy recommendations contained in the draft Report to register ABATE's position regarding important policy questions that impact the provision of DR generally in Michigan. The Comments are organized in a manner that is consistent with the subject matter headings contained in the draft Report.

PERFORMANCE OBLIGATIONS AND UNINTENDED INCENTIVE

In this section of the draft Report, Staff discusses the pros and cons of the two prevalent means of measuring DR performance in response to curtailment calls: the targeted reduction or

[1] Michigan Public Service Commission Staff, *Draft Demand Response Report*, July 1, 2020.

Guaranteed Load Drop ("GLD") approach vs. the Firm Service Level ("FSL") approach of reducing load to a previously agreed firm load level during curtailment periods. In discussing the GLD vs. the FSL approaches to measuring DR performance, the draft Report notes that stakeholders cautioned against mandating one approach over the other. It was also noted that some customers may favor the FSL approach because it provides additional flexibility to customers who may wish to ramp down more gradually to a set load level in order to avoid damage to their equipment.[2]

The aforementioned discussion highlights the fact that providing flexibility in DR requirements is the key to expanding DR participation and will help to reduce the cost of such participation for customers. Therefore, Michigan should not attempt to impose a standardized approach to this issue and should continue to allow customers the flexibility to select between the GLD and FSL options depending on their unique circumstances. To emphasize this point, ABATE recommends that the following language be added to this section of the Report:

> In order to facilitate DR participation, it is important that DR customers continue to have the flexibility to select the DR performance measurement approach that best suits their operational requirements. Therefore, customers should continue to be able to select either the Guaranteed Load Drop or the Firm Service Level option for measuring DR performance, and the Commission should not mandate the use of any single DR performance measurement approach.

UTILITY DEMAND RESPONSE TARIFFS

This section of the draft Report includes a discussion of utility DR offerings that are negotiated between the utility and an individual customer.[3] A concern about such offerings is that while information may be available online, these contract-based DR programs are not included in utility tariffs. While the draft Report highlights the fact that these contract-based DR programs

[2] Draft Report at 18.
[3] Draft Report at 21.

provide great flexibility to negotiate the terms of DR participation on an individual customer basis, it is important to enhance the transparency of these contract-based DR programs in order to ensure that all eligible customers can take advantage of these programs on a non-discriminatory basis. Therefore, ABATE recommends adding the following language to this section of the Report to address this concern:

> through contracts (e.g. CE's C&I DR Program). These contract-based programs offer the greatest flexibility by allowing the utility and customer to agree on the exact terms of their participation in DR. However, ~~C&I customers are not aware of these contract-based DR programs. T~~the utility tariffs do not mention these contract-based DR programs~~, and information regarding these programs is not readily available on the utility websites~~. To enhance the transparency of utility DR offerings, utilities should be required to have a tariff sheet approved by the Commission that provides information regarding all of the DR programs that they provide within their respective service areas, including contract-based programs. The DR program information provided in the utility tariffs should not be restricted to the standard interruptible rates that the utilities offer.

ENSURE LMR AVAILABILITY IS PROPERLY ACCOUNTED FOR IN MISO'S MCS TOOL

In this section of the draft Report, Staff states that DR resource availability should be accurately represented in the MISO Communication System ("MCS").[4] However, the draft Report acknowledges at that these reporting issues have already been largely addressed through changes that have been made since January 2019. Moreover, during the July 2020 meeting of the MISO Resource Adequacy Subcommittee, MISO indicated that it plans to commence a stakeholder process to further examine the MCS reporting requirements for DRs over the next several months, and MISO may make a filing at the Federal Energy Regulatory Commission ("FERC") regarding its MCS reporting requirements to address this issue at some point in the future.

[4] Draft Report at 23.

In comments filed during the MISO stakeholder process, ABATE and other end-use customer representatives explained that the reported availability data in the MCS does not provide an appropriate basis for determining the accreditation of DRs that use the FSL option, or for Behind the Meter Generation ("BTMG").[5] To address these concerns, it is important that any proposed changes to the MCS reporting and related capacity accreditation requirements be thoroughly vetted through the MISO stakeholder process in order to ensure that the MCS data is used in an appropriate manner that reflects the characteristics of the various DR resources in MISO.

The MISO stakeholder process is the appropriate forum to address any concerns regarding the DR reporting procedures in the MCS. The MISO stakeholder process on this issue should be allowed to take its course before taking any additional steps on the topic of MCS reporting requirements at the state level. Therefore, there is no need to recommend any changes to the DR reporting requirements in the MCS at this stage. To address this issue, ABATE recommends that the following language be added to this section of the draft Report:

> Stakeholders have expressed serious concerns regarding the suitability of relying on DR availability data in the MCS for the purpose of establishing the capacity accreditation of DR resources. MISO is planning to undertake a stakeholder process to evaluate potential changes to the MCS reporting requirements for DRs. Staff recommends that this stakeholder process be allowed to take its course before taking any additional actions with respect to the MCS reporting requirements for DRs at the state level.

[5] Joint Comments of the Association of Businesses Advocating Tariff Equity (ABATE), the Illinois Industrial Energy Consumers (IIEC), the Louisiana Energy Users Group (LEUG), the Texas Industrial Energy Consumers (TIEC), the Coalition of MISO Transmission Customers (CMTC), the Midwest Industrial Customers (MIC) and Alcoa Power Generating, Inc. (APGI) on MISO RASC: RAN LMR Accreditation, February 19, 2020.

EXPLORE THE USE OF ENABLING TECHNOLOGIES WHERE FEASIBLE AND COST EFFECTIVE

In this section of the draft Report, Staff recommends that DR providers should be directed to make full use of the existing infrastructure and make the case for new technology as it develops.[6] While ABATE supports the use of new technologies that facilitate the deployment of DR in Michigan, the Report should clearly emphasize that new DR technologies and software platforms should be subject to a demonstration that they are cost effective. This is a necessary safeguard to ensure that the benefit of the new technologies to Michigan customers outweighs the associated cost. Therefore, the Report should stress that the cost of new, enabling DR technologies is an important factor in the decision to proceed with any such technologies. DR providers should only implement the modern technologies and software platforms addressed in the draft Report if it can be demonstrated that these technologies provide benefits in the form of expanded and more efficient DR deployment that exceed the associated implementation costs. ABATE recommends that this section of the draft Report include the following language to address this concern:

> The deployment of new, enabling DR technologies or software platforms is only justified where the benefits of the technologies in the form of expanded and more efficient DR deployment can be demonstrated to exceed the associated implementation costs. Therefore, the deployment of such new DR technologies should be subject to an appropriate cost-benefit analysis prior to deployment.

REQUIRE AN ANNUAL DOCUMENTED SIMULATION, ENCOURAGE REAL POWER TESTING WHERE FEASIBLE

This section of the draft Report suggests that real power testing may be the preferred method to ensure reliability under emergency conditions and suggests that DR providers should

[6] Draft Report at 23-24.

be encouraged to perform a real power test where it is cost effective to do so.[7] ABATE is concerned that the draft Report places inordinate emphasis on conducting real power testing. This emphasis does not appropriately recognize that the applicable Regional Transmission Organizations ("RTOs") in Michigan do not uniformly require real power DR testing at this time. As the draft Report notes at page 10, MISO currently allows an opt-out from real power testing requirements, subject to a penalty for non-performance. Michigan should not mandate a real power curtailment test that would effectively eliminate this optionality. Moreover, DR testing requirements for Michigan customers should not be more stringent than what the applicable RTO currently requires.

As noted on page 16 of the draft Report, DTE Energy Company ("DTE") has found that the cost and inconvenience of a real power testing requirement would be high. The draft Report also observes that Hemlock Semiconductor was able to fully perform during 2019 DR curtailment calls, when real power testing was not required, due to robust operating procedures and documented simulations. In addition, the draft Report highlights the Foundry Association of Michigan's determination that real power testing would be deleterious to its members.

As the draft Report notes at page 24, rigorous simulations can provide a reasonable substitute for a real power test. Therefore, Michigan should not impose a real power DR testing requirement. Instead, Michigan should allow customers to rely on simulations in order to reduce the cost and burden of DR participation. This optionality would help to ensure the continued participation of existing customers in DR programs and also help to expand DR participation. Accordingly, ABATE recommends the following changes to this section of the draft Report:

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[7] Draft Report at 24-25.

> ~~While real power testing may be the preferred method to ensure reliability under true emergency conditions, the~~ The MPSC Staff recognizes that a real power testing requirement would adversely ~~the~~ impact ~~such a test may have on the~~ customer~~'s~~ operations and increase the costs of DR participation. Rigorous simulations, documented for the benefit of the customer, utility, and RTO, ~~may~~ provide a reasonable substitute for a real power test. Simulations should reproduce emergency conditions, enable the customer to walk through each step of the emergency procedures, and provide an opportunity for after the fact learnings. If approached in this manner, simulations balance the reliability need of the system with the economic impact of a real power test. However, the severity of such economic impacts differs across customer classes and even individual customer sites. For example, heavy manufacturing and industrial processes incur a greater power interruption cost than a residential AC system. ~~To the extent practicable, DR providers should be encouraged to perform a real power test where it is cost effective to do so. This could include testing only a portion of the customer's accredited load reduction, which could provide valuable insight into the reliability of the resource while minimizing the impact to the customer.~~ To minimize the cost and burden of DR participation in Michigan, DR providers should have the option of relying on rigorous and documented curtailment simulations in lieu of conducting a real power curtailment test, where applicable RTO rules allow for such optionality. Utilities should be directed to list testing procedures in their retail tariffs, which would enhance accountability for ratepayers, who will be assured that the resource they pay for is available, and for the utility, who is ultimately responsible for the load reduction at MISO.

FORMALIZE AND STANDARDIZE THE NOTIFICATION PROCEDURE AND PENALTIES IN UTILITY TARIFFS

Staff recommends that the notification response window for DR curtailment calls be made consistent across utilities.[8] ABATE is concerned that a "one size fits all" approach to the notification response window may not match the operational requirements of some customers and may therefore unnecessarily restrict DR participation. A superior approach would be to standardize the availability of certain interruptible service features across Michigan utilities, but to also provide standardized optionality within these features with respect to the length of the curtailment period and the number of allowed calls. Specifically, each utility should be required to offer DR programs

[8] Draft Report at 25.

that contain a standardized menu of options that would allow customers to select the length of the curtailment period and the number of allowed curtailment calls that best suits each customer's operational requirements. Within this menu of options, shorter notification times and a larger number of allowed curtailment calls should receive higher levels of compensation because they provide enhanced responsiveness during system emergencies.

Other features that should be standardized and that all Michigan utilities should be required to offer to interruptible customers include the option of providing load curtailments for both economic and reliability reasons, varying limits on the duration of interruptions over the course of the month/year, as well as the ability to buy-through economic interruptions by paying the prevailing real-time Locational Marginal Price ("LMP") for power purchases that occur during an economic curtailment. For the utilities in MISO, the compensation levels for the various DR response options can be integrated with the DR accreditation requirements that are pending before the FERC in Docket No. ER20-1846-000.[9]

As previously noted, another area where the standardization of utility DR programs should be enhanced concerns the level of transparency that the utilities provide with respect to contract-based DR programs. To alleviate this problem, this section of the Report should also include a recommendation that Michigan utilities must be required to file tariff sheets that provide information regarding all of the DR programs that they offer, including contract-based programs. To address the foregoing concerns, ABATE recommends the following changes to this section of the draft Report:

[9] Midcontinent Independent System Operator, Inc, *Filing to Enhance Accreditation of Load Modifying Resources Participating in MISO Markets,* Docket No. ER20-1846-000, May 18, 2020.

phone call, etc. A customer's preference should not preclude the utility from using multiple communication avenues during events. ~~In addition, Staff recommends that the notification response window, how long the customer has until it must reduce load following a call from the utility, be made consistent across utilities. This way, an interruptible customer being served by different utilities at different locations would have the same expectations of interruption during an emergency event.~~ Staff recommends that the Commission commence a proceeding to standardize the availability of certain interruptible service features across utilities in the state in a manner that provides standardized optionality within these features with respect to the length of the curtailment period and the number of allowed calls. Within this menu of curtailment options, shorter notification times and a larger number of allowed calls should receive higher levels of compensation because they provide enhanced responsiveness during system emergencies. Other features that should be standardized and that all Michigan utilities should be required to offer to interruptible customers include the option of providing load curtailments for both economic and reliability reasons, varying limits on the duration of interruptions over the course of the month/year and the ability to buy-through economic interruptions by paying the prevailing real-time Locational Marginal Price ("LMP") for power purchases during an economic interruption. The compensation levels for the various DR curtailment options in Michigan can be coordinated with the applicable RTO requirements. Of course, compensation for load curtailments should reflect the full value that DR resources provide to the system, including scarcity or congestion premiums for curtailments that are called to alleviate resource scarcity or congestion on the system. As part of the process of standardizing DR offerings, the Michigan utilities should be required to have a tariff sheet approved by the Commission that provides information regarding all of the DR programs that they provide within their respective service areas, including contract-based programs. Such tariff information should not be restricted to standard interruptible rates.

ADDITIONAL RECOMMENDATION RELATED TO BUNDLED CUSTOMER PARTICIPATION IN RTO DR PROGRAMS

ABATE notes that the draft Report does not include any recommendations with respect to expanding DR opportunities for customers in Michigan by allowing bundled utility customers to participate in the RTO DR markets, whether directly or through a utility tariff that is designed for this purpose. ABATE strongly urges the Staff to include such a recommendation in its final Report. DR provides an array of valuable operational, planning, economic, and environmental benefits to Michigan. To maximize these benefits, the Commission should pursue all reasonable opportunities to expand cost-effective participation of DR resources in Michigan. The dramatic increase in

Michigan capacity prices in the most recent MISO Planning Resource Auction and MISO's increasing reliance on DR resources during emergency periods highlight the importance of expanding DR deployment in Michigan. DR resources provide a cost-effective means of expanding the supply of capacity in the state, mitigating capacity market price increases, and enhancing the system's responsiveness during emergency conditions.

To advance these important objectives, Michigan should allow bundled utility service customers to participate in RTO DR programs. There is no valid reason to restrict access to RTO DR programs only to customers that take unbundled retail service from competitive third-party power providers. The current ban on DR participation by bundled retail customers in the RTO markets is discriminatory and unnecessarily limits the scope of DR in Michigan simply because the customers who could provide such resources happen to take their power supply from a bundled utility rather than an AES. Moreover, this artificial barrier to the expansion of DR hinders Michigan's efforts to meet its energy conservation and environmental goals.

For these reasons, ABATE urges the Staff to include a recommendation in its Report that would require utilities to propose and implement new tariff offerings that would allow bundled service customers to voluntarily participate in the MISO markets as a DR resource, directly or through their electric utility. Such action would provide Michigan with a valuable new mechanism to expand the deployment of DR resources to the benefit of the entire customer base. These utility tariffs would establish the terms and conditions for bundled customer participation in the DR markets. The details of the terms and conditions could be addressed before the Commission in a formal proceeding to ensure that all the Commission's concerns regarding DR participation in RTO markets are comprehensively resolved. For the reasons discussed above, ABATE recommends that the Report include the following recommendation:

X. Allow Participation by Bundled Service Customers in RTO DR Markets

DR provides an array of valuable operational, planning, economic, and environmental benefits to Michigan. To maximize these benefits, the Commission should pursue all reasonable opportunities to expand cost-effective participation of DR resources in Michigan. The dramatic increase in Michigan capacity prices in the most recent MISO Planning Resource Auction and MISO's increasing reliance on DR resources during emergency periods highlight the importance of expanding DR deployment in Michigan.

To advance these important objectives, Michigan should allow bundled utility service customers to participate in RTO DR programs. Utilities in Michigan should be required to propose and to implement new tariff offerings that would allow bundled service customers to voluntarily participate in the RTO markets as a DR resource, directly or through their electric utility. This would provide Michigan with a valuable new mechanism to expand the deployment of DR resources to the benefit of the entire customer base. These utility tariffs would establish the terms and conditions for bundled customer participation in the DR markets. The details of the terms and conditions could be addressed before the Commission in a formal proceeding to ensure that all of the Commission's concerns regarding DR participation in RTO markets are comprehensively resolved.

CONCLUSION

ABATE appreciates the opportunity to submit these Comments regarding the Staff's draft Report. As part of its Comments, ABATE is also providing a redlined version of the draft Report that incorporates ABATE's suggested changes to the Report. We urge Staff to modify the draft Report in a manner that is consistent with the recommendations set forth in these Comments. ABATE also requests that its Comments be included in the appendix to the Staff's final Report to the Commission.

Respectfully submitted,

CLARK HILL PLC

By: ____________________________________

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Dated: July 17, 2020

ACEEE Comments to the Michigan Public Service Commission on the

July 1, 2020 *Draft Demand Response Report*

July 17, 2020

The following comments are submitted to the Michigan Public Service Commission on behalf of the American Council for an Energy Efficient Economy (ACEEE).

The American Council for an Energy-Efficient Economy (ACEEE) is a non-profit research organization that works on programs and policies to promote energy efficiency. We have been active on energy efficiency issues for more than three decades, collecting extensive best-practice information on approaches to utility regulation. We regularly monitor utility sector energy efficiency and demand side resource policies and programs in states across the nation.

ACEEE would like to offer one major comment on the draft report. That is, we found it surprising and disappointing that there was absolutely no mention of energy efficiency, or Energy Waste Reduction, in the entire report. Demand Response/Load Management is a demand side resource that needs to be thought about in the context of other possible demand side resources, in particular, energy efficiency. The industry has long recognized the possible synergies from coordinating the deployment of technologies that reduce energy use (kWh) and peak demand kW.[1] The National Action Plan for Energy Efficiency found significant potential customer benefits from integrating demand response and energy efficiency programs, including:

- Lower rates, which resulted in bill savings (including for nonparticipants)
- Increased bill savings through DR payments, time-varying rates, and reduced energy use
- Increased overall program satisfaction
- Increased ease of participation through a single program contact for multiple services
- Increased ease of participation through a single, clear program entry point or enrollment process
- Lower program costs
- Fewer power outages (from increased grid reliability)[2]

[1]Potter, J., E. Stuart, and P. Cappers. 2018. *Barriers and Opportunities to Broader Adoption of Integrated Demand Side Management at Electric Utilities: A Scoping Study.* Prepared by Berkeley Lab. eta-publications.lbl.gov/sites/default/files/barriers_and_opps_idsm_final_03222108.pdf.; EPRI (Electric Power Research Institute). 2009. *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010–2030).* ma-eeac.org/wordpress/wp-content/uploads/14_-Assess.-of-Achievable-Pot.-from-EE- and-Demand-Response-2010-2013_Siddiqui_Study .pdf.; Goldman, C., M. Reid, R. Levy, and A. Silverstein. 2010. *Coordination of Energy Efficiency and Demand Response*. Prepared by Berkeley Lab. Washington, DC: DOE. emp.lbl.gov/sites/all/files/report-lbnl-3044e.pdf.; York, D., and M. Kushler. 2005. *Exploring the Relationship between Demand Response and Energy Efficiency: A Review of Experience and Discussion of Key Issues.* aceee.org/research-report/u052.

[2] NAPEE (National Action Plan for Energy Efficiency). 2008. National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change. Washington, DC: EPA (Environmental Protection Agency). epa.gov/sites/production/files/2015-08/documents/vision.pdf.

Further benefits include those to the grid, from greater resource adequacy and transmission congestion relief, and to private markets that could capture the value from integrated programs by offering nonwires solutions opportunities or aggregation of integrated energy efficiency and demand response resources.[3]

Unless properly considered and planned for, demand response and energy efficiency programs and efforts can cause confusion and even come into conflict. As a general principle, cost-effective energy efficiency opportunities should be captured first. **It is a sub-optimal solution to merely shift the timing of an inefficient load.** Demand response programs should be designed to be integrated with appropriate energy efficiency programs and information, so that customers are fully aware of their options, and so that optimal energy solutions for the customer and the electric system can be fully considered.

ACEEE recommends that discussion of the need and opportunity for integrating demand response and energy efficiency options be added to the report before it is finalized. ACEEE would be happy to provide additional information to Staff to help facilitate that objective.

ACEEE appreciates the opportunity to provide comments in this docket. I would be happy to answer any questions or provide further information.

Sincerely,

Martin Kushler, Ph.D.

Senior Fellow, ACEEE

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[3] York, D. G. Relf, and C. Waters. *Integrated Energy Efficiency and Demand Response Programs.* https://www.aceee.org/research-report/u1906

MI Power Grid – Demand Response Workgroup
DTE Electric's comments on Staff Report
July 24th, 2020

DTE Electric (DTE or Company) would like to first extend its appreciation for the hard work of the Michigan Public Service Commission Staff (Staff) and all parties involved in this Demand Response (DR) workgroup. The level of participation has been outstanding and has addressed multiple important topics throughout the course of the four workgroup sessions, and in the subsequent draft report. On July 17th DTE provided feedback via a "redline" version of Staff's draft report, with some suggested modifications, word changes, and general comments. Below are additional comments that the Company believes are important to note:

1. DTE believes it is important to clearly articulate the role of DR aggregators, and the various terms used to describe the aggregator-utility partnerships. Various terms have been used to describe these partnerships which can lead to confusion. DTE notes that currently its "partnerships" with DR aggregators are not in the true sense of an *aggregator*, but in a *service provider or program implementer* role. This is when a 3rd party provides a service to the utility, in which the 3rd party possesses expertise that is desired by the utility, for an agreed upon fee and contract. Some examples of services provided today include marketing services and platform management.

2. The Company will continue to support and pursue partnerships with service providers, but opposes third-party aggregation of bundled load, and echoes the same concerns as filed in case U-20348. Furthermore, Staff's report on DR Aggregation resulting from case U-20348 recommended the Commission not allow third-party aggregation of bundled utility load. As previously stated in prior cases regarding DR aggregation, DTE opposes the aggregation of bundled load for the following reasons:

    a. Creates cross subsidization and cost recovery issues and primarily benefit the participating customer and aggregator – but not the broader customer base.
    b. Negatively affect the utilities' ability to forecast capacity needs and consider demand response in their long-term resource planning.
    c. Operational conflicts between DR dispatch in wholesale markets and the need to utilize it for distribution load relief.
    d. Allowing aggregators of retail customers to directly bid DR into wholesale markets has adverse operational impacts.

    Aside from the issues referenced above, there are other concerns to consider.

- o DTE believes that allowing third party aggregation for utility customers runs counter to the 10% cap established by the Customer Choice and Electricity Reliability Act. The Act reserves 90% of an electric utility's retail market for the provision of service by the utility. This provision of electric generation service includes both energy and capacity service, and demand response can participate in both. Allowing third parties to bid demand response into the MISO market on behalf of a utility's retail customers would erode a portion of the market that the statute preserved for utilities.
- o The MPSC has the authority to prohibit retail customers from participating in wholesale DR markets, but that does not mean that it necessarily has authority to regulate that activity.

3. DTE opposes the recommendation to use the same notification window and penalties across all utilities. Today's utility DR programs serve different needs to different groups of customers in different service territories. Standardizing notification windows across all utilities could have unintended consequences in which it takes away flexibility to tailor specific program offerings to customers. Smaller notification windows may be appropriate for different programs. DTE has the same viewpoint on the topic of standardizing non-compliance penalties as well. Penalties are not cost-based, but are there to ensure compliance with interruption, when called.

4. The draft report recommends that "any necessary tariff changes should be made in a general rate case or ex parte case". DTE would like to note that DR reconciliation cases would be another acceptable avenue.

5. In terms of DR value stacking, Staff has recommended that pilot programs be utilized for testing of dual-registration options. The Company agrees that pilot programs can be a useful avenue for testing out new options. DTE would also note that pilots should be pursued with the main goal of exploring performance and benefits to customers. The cost effectiveness of a pilot should be considered but should not necessarily be a barrier. The goal of a pilot program should be to learn as much as possible. The Program and Technology Pilot workgroup (part of MI Power Grid) has addressed this is a similar manner.

Respectfully submitted,

Keegan O. Farrell
Principal Supervisor – Demand Response

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to commence a collaborative to consider issues related to implementation of effective electric demand response tariffs and efficient deployment of load-modifying resources.	)))))	Case No. U-20628

INDIANA MICHIGAN POWER COMPANY'S COMMENTS TO THE MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S DRAFT DEMAND RESPONSE REPORT

Pursuant to the Michigan Public Service Commission's (MPSC) September 11, 2019, Order in Case No. U-20628, Indiana Michigan Power Company (I&M or the Company) submits these comments in response to the MPSC Staff's Draft Demand Response Report (Report or the Report) that was published on July 1, 2020.

I&M appreciates the time and effort that interested Stakeholders have put into providing feedback in Case No. U-20628, and the Commission's efforts to facilitate discussion by hosting the stakeholder information sessions. The Staff requested all comments on this Report be submitted to the Commission by July 17, 2020. I&M carefully reviewed the Report and compiled comments to several sections. The Company looks forward to continuing the dialogue and discussion on these topics.

I&M BACKGROUND

I&M is an electric operating company and wholly owned subsidiary of American Electric Power Company, Inc. (AEP). I&M's electric system is completely integrated and interconnected and is operated as a single utility in the American Electric Power System (AEP System). I&M

serves both retail and wholesale customers located in Indiana and Michigan. Currently, I&M serves approximately 599,000 retail customers, including approximately 469,500 in Indiana and 129,500 in Michigan.

I&M participates as a generator owner and operator, transmission owner, and Load Serving Entity (LSE) in PJM Interconnection, LLC (PJM), a Regional Transmission Organization (RTO) regulated by the Federal Energy Regulatory Commission (FERC). PJM manages the high-voltage electricity grid to ensure reliability for more than 65 million people and operates a competitive wholesale electricity market in the mid-west and eastern portions of the country. I&M, as a PJM member, benefits from a mature and robust demand response market, established rules and regulations, and more than a decade of experience operating demand response programs. The recommendations in the Report focus mainly on MISO. As explained further in I&M's comments, the objectives and goals of Staff's recommendations are in many cases already accomplished through the delivery of I&M's demand response programs in PJM.

STATUS OF DEMAND RESPONSE IN I&M AND PJM

I&M has been a strong proponent of Demand Response (DR) programs, with PJM DR programs available to customers in Michigan and Indiana, and was named as the Demand Response Program Pacesetter in 2018 by Peak Load Management Alliance. As of June 1, 2020, I&M has 136 customer accounts, representing 260 MW footprint wide, registered and participating in PJM's DR program as emergency resources, both directly with I&M and through third-party Curtailment Service Providers (CSPs). All of I&M's customers benefit from DR participation regardless of where in I&M's system the participating customer is located. I&M's Customer Service Support staff and AEP National Accounts Managers communicate demand response programs to this sector of customers, and Customer Service Engineers work directly with their managed accounts to communicate the programs and program changes.

I&M's long-established and developed voluntary DR program compensates retail customers for reducing their electrical load, when requested by PJM, during periods of high power prices or when the reliability of the grid is threatened. Emergency demand response is a mandatory commitment to reduce load or only consume electricity up to a certain level when PJM needs assistance to maintain reliability under supply shortage or expected emergency operations conditions, and there are significant penalties for non-performance. PJM's demand DR resources are one of the resources relied upon to prevent rolling brown-outs or blackouts.

As part of its participation in PJM and to support its tariff offerings, I&M has established a centralized communication system to manage all of the communications with PJM's version of MISO's Load Modifying Resources (LMR). The software monitors PJM instructions and then communicates those instructions, in a user format, to DR participants via preconfigured emails, text messages, and phone calls. As of June 1, 2020, all DR participants are subject to PJM's Capacity Performance (CP) rules, which include significant penalties for non-performance. In order to insure DR participants are properly prepared for the increased performance risk, I&M's Customer Service team was trained on the new rules and worked closely with participating customers to insure that customer participants were aware of program changes and the increased risk of underperformance during a PJM event. In addition, these changes have been reflected in updated contracts with each of I&M's DR participants. I&M also thoroughly vetted its DR processes to support reducing the risk of underperformance by participants when called.

Further, AEP has developed additional Peak Shaving Adjustment (PSA) programs. These programs allow DR participants to provide services to the utility that are based upon active reductions throughout the capacity year, which, if implemented, would allow both the participant and I&M to mitigate capacity performance exposure. There is room for utility load side programs, such as the PSA programs, to coexist with supply-side programs.

As a result of its customers' participation in the PJM DR programs, the Company has had significant interactions and experiences with DR aggregators. The majority of I&M's experience with third-party DR aggregators has been positive, but as a result of the new PJM CP rules which went into effect on June 1, 2020, the Company's relationships with aggregators is even more critical.

The CP rules amplify the risk of nonperformance and come with heavy penalties. Thus, accurate and authentic participation is more important than ever. With these concerns in mind, any DR tariff language must hold third parties participating in DR programs accountable for their conduct. Any conduct that unnecessarily exposes potential participants to risk based upon questionable claims, especially with the possibility of significant penalties for non-performance, should not be allowed. While most third-party CSPs adhere to reasonable standards, the Company and its customers have experienced questionable program recruitment practices by some DR aggregators. These lessons learned warrant attention in the Commission's decision-making process to ensure that aggregators, if permitted, are held accountable for conveying the specific DR program requirements, benefits, and penalties for non-performance. This is intended to ensure that customers fully understand the DR product and its potentially significant costs of non-performance. Finally, it is also important the Commission approve tariff language or terms and conditions of service that insure that, to the extent CSPs represent customers who participate in DR programs, the CSPs are financially responsible for any penalties that may be incurred due to non-performance of their participants. In this way, the CSPs and their customers are responsible for their performance, the same as customers participating in these programs through the utilities.

I&M COMMENTS TO DRAFT RECOMMENDATIONS

I. Ensure LMR availability is properly accounted for in MISO's MCS tool

I&M's DR programs require registration and do not permit duplicate entries. PJM requires that CSPs register demand resources in PJM's system, referred to as the DR Hub. The CSPs, with the determined aggregate commitment of their individual customers, are required to meet their commitments or be subject to penalties for non-performance, which can exceed the benefits derived from their participation. Thus, the PJM process, which applies to the Company today, conforms with Staff's recommendation and objectives.

II. Ensure clarity and consistency in communication processes

I&M maintains a robust communication process with its customers, including contractual arrangements with each participant, which allows I&M to achieve the objectives of Staff's recommendation. As discussed in the Staff's draft Report, it was clear during the workgroup sessions that communication problems were a major issue during the Polar Vortex 2019 (PV19). During the PV19, both I&M's and PJM's generation resources performed well and provided adequate and reliable power to I&M's customers. As such, I&M did not experience impacts like the members of the MISO RTO reported and dealt with during PV19. However, as discussed above, I&M continues to keep communication as a focus, particularly with the new PJM rules that have raised the stakes for all participants and will continue to be vigilant with the more significant PJM DR penalties for non-compliance.

III. Increase DR provider interaction with the customer

I&M, through its DR subject matter experts, maintains multiple levels of customer engagement with DR participants, which are described above. It is important for the utility to take the lead on these interactions and make certain that there are no gaps in communication. Establishing a formal requirement around its communication with its participating customers may hinder the Company's ability to take the lead on its interactions with its participating customers and hinder its ability to address new issues that may arise through its customers' participation in DR programs. This is an ongoing focus of the Company and will remain central to the success of any I&M DR Programs. At this time, I&M's interactions with CSPs are in-line with the spirit of Staff's recommendations and it is unnecessary to establish formal requirements around interactions with DR customers.

IV. Explore the use of enabling technologies where feasible and cost effective

I&M agrees that, when cost effective, utilizing new technologies can benefit all participants. From a connected-customer perspective, I&M is reviewing different program offerings for both the residential and C&I sectors that promote utility connectivity and access to customer-owned, WiFi connected, or smart control systems. Through this approach, I&M can capitalize on gaining control of energy consuming devices for the purposes of peak-period demand response or pricing response activities in a "light touch" approach that still yields customer control of their systems.

As an example, I&M is currently developing and planning customer pilot programs that study how, and to what extent, customers can realize the energy savings benefits, and control, of their energy intensive uses and processes through control systems such as energy management systems and connected energy savings measures. On the utility grid side, I&M is both studying and planning pilots for how enabling technologies, such as grid connected batteries, micro grids, and other supply options, can interface with the grid to reduce system peak period usage.

V. Direct utilities to explore DR partnerships for real-time metering, customer readiness, and a centralized platform

While the MISO DR markets are still evolving, the PJM markets have already provided the foundation for these interactions and partnerships. I&M has extensive experience in the mature PJM DR markets and has interacted with DR aggregators for well over a decade and, therefore, would recommend to Staff that this recommendation not apply to PJM participants.

VI. Require an annual documented simulation, encourage real power testing where feasible

I&M agrees with Staff regarding the importance of testing and works closely with its customers and CSPs to ensure that they are able to perform in line with their DR program commitment. PJM requires annual testing for all of I&M's customers, assuming there is no event during the year. It is important that any testing requirements that I&M would be subject to align with PJM's testing requirements, both presently and for future PJM revisions.

VII. Formalize and standardize the notification procedure and penalties in utility tariffs

PJM has a formalized process for event notifications, as well as penalties for non-performance that I&M incorporated into its tariffs and contracts. The method of communication of events, as well as customer and Company responsibilities around curtailment event notifications, are also spelled out therein. Penalties for testing or emergency event non-performance are described in detail including penalty calculation methodology, so prospective participants understand the importance of event and testing performance.

The Company would also recommend the Staff Report to make clear that, should Staff continue to recommend that penalties be made consistent across the utilities, the penalties should consistent across the utilities based on the RTO in which they participate. To make uniform penalties across all utilities may lead to inconsistent requirements for the Company as PJM's penalties may be different than those applicable to utilities operating within MISO. Therefore, I&M's administration of its DR programs meets the objectives of Staff's recommendations and I&M recommends that it be allowed to continue establishing penalties consistent with PJM requirements, not the other Michigan utilities operating in MISO.

VIII. Any necessary tariff changes should be made in a general rate case or an ex parte case

I&M does not take issue with using either a general rate case or an ex parte case filing to request future tariff changes. However, I&M supports expanding the filing options to seek approval of new programs, changes to existing programs, tariff changes and associated cost recovery. In addition, if the Commission were to require changes or updates to I&M's tariff, I&M would request that the Commission allow for cost recovery for any costs incurred to accomplish the tariff changes.

IX. Enable DR value stacking

This recommendation is not necessary for I&M due to PJM's DR program requirements. While there are DR products that complement each other within PJM, there are also rules around those products to avoid both conflicts and duplicative compensation.

SUMMARY

As discussed in detail above, I&M is differently situated from its Michigan utility peers because it participates in the PJM market, where DR programs are much more mature and robust. While many of the recommendations focus on MISO utilities, the many differences between the MISO and PJM RTOs result in the recommendations not being necessary or appropriate for I&M,

for the reasons elaborated above. The areas identified, including registration tools, communication processes, increased communications with DR customers, enabling technologies, centralized platform for customer readiness, performance testing, penalties for non-performance, and formalize processes in tariffs, are all important criteria for having a well-developed DR program that are already in place in PJM.

I&M encourages all of the participants in this DR collaborative to continue to look both at load side solutions, such as peak shaving, as well as to the PJM DR markets to seek ideas for improving and advancing these criteria to enhance the overall Michigan DR experience for all participants. The DR workshops, dialogue, and resulting Report are all promising steps toward a better DR market for Michigan, and I&M welcomes additional opportunities to participate in this process.

Respectfully submitted,

INDIANA MICHIGAN POWER COMPANY

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July 23, 2020

Dear Commissioners Scripps, Talberg, and Phillips,

Thank you for the opportunity to comment on the MI Power Grid Demand Response workgroup's report. The workgroup, and the resulting report, provided valuable insights into the current state of the demand response market in Michigan and the potential of demand response to meet Michigan's most pressing energy needs in an economical, reliable, and environmentally-sustainable way.

> **In light of this, it has never been clearer that the MPSC needs to lift the ban on Aggregators of Retails Customers (ARCs) for the 90% of Michigan load that is not in the Retail Choice program.**

The current state of the Michigan demand response market is overpriced and underperforming; ARCs, and their focused, innovative approach to demand response, will provide lower cost, more reliable, local capacity at a time when Michiganders need it most.

Michigan has paid an MPSC-approved, weighted average of $95,241 per MW per year for capacity to its regulated utilities over the past five years. Michigan peak demand is approximately 20,828 MWs of which 90% is delivered through regulated utilities. That amounts to $1.8 billion per year in capacity costs to Michigan ratepayers. The MISO Michigan price (zones 7 and 2) for capacity has cleared, on average, at $26,674 per MW per year for the past five years. The difference of these prices would amount to a $1.3 billion per year savings to Michiganders, or approximately $340 per Michigan household per year. Those savings are before taking into consideration what additional MWs from demand response would do to MISO zones 7 and 2 prices (i.e., unlocking more demand response MWS would reduce the MISO PRA price further, substantially increasing annual savings).

It is estimated that Michigan has the potential of more than 2,000 MWs of demand response[1] by the year 2023, most of which is lying fallow today, and could be unlocked by allowing ARCs to bring all Michigan demand response into the MISO wholesale market programs where those MWs are not currently being delivered by a Michigan utility. By way of comparison, in the Southern Illinois region of MISO (zone 4), more than 900 MWs of demand response is being delivered by ARCs in a region with a system peak of approximately 9,000 MWs, which was accomplished in less than three years. This amounts to more than the combined demand response capacity of all Michigan regulated utilities over the past ten years in a region with more than twice its peak demand.

Finally, demand response, by its very nature, is a local resource. Michigan has stated that it desperately needs more local resource[2], and for good reason. Michigan's transmission constraints require that nearly 100% of resource adequacy requirements be delivered within its MISO zones. Unlocking demand response's full potential by lifting the 10% administrative limit would help Michigan drive costs down in the MISO auction while gaining much needed local resilience.

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[1] https://www.michigan.gov/documents/mpsc/State_of_Michigan_-_Demand_Response_Potential_Report_-_Final_29sep2017__602435_7.pdf
[2] https://www.michigan.gov/documents/mpsc/LCR_Issue_Brief_062818_626553_7.pdf

Good afternoon,

Consumers Energy recognizes the time and effort taken by the MPSC Staff to develop a thorough report, and appreciates the opportunity to provide feedback. The company would note the following:

- In the initial draft, the term “aggregator” is used quite often. However, the services discussed are not truly aggregation services but rather services to support demand response irrespective of aggregation activity. Consumers Energy would like to respectfully suggest the term “utility service provider” or “DR provider” be used in most cases rather than the term “aggregator” to clarify that the MPSC Staff and workgroup support the services that would likely be offered to and through utilities versus actual third-party aggregation of customers.

- On page 5 of the initial draft, a summary of the presentation by Voltus to the workgroup is provided within the context of the 2019 Polar Vortex event. However, Voltus themselves noted that their programs are only offered for three summer months and they did not provide any services during that time period. Consumers Energy / Utilities respectfully suggest that the information provided by Voltus would be more appropriately placed under the LMR Operations and Communications section rather than the PV19 section.

- Consumers Energy understands the benefits of standardization of the rate schedules or tariffs and providing consistency in understanding programs. The company respectfully suggests that, in standardizing tariffs and including key items within them, the requirement for a notifications and testing can be included within the rate schedule but without the actual procedures. The company needs flexibility in managing the operation of notifications and testing but agrees that an expectation within the tariff for these items is reasonable.

  The company also notes that, while it may seem that the notification response window can be consistent, given that utilities in Michigan operate under two different RTOs and to accommodate operational needs of customers, the notification response cannot necessarily be standardized throughout the state of Michigan and possibly not even within a utility. Variances exist due to the manner in which resources are registered with the RTO, and in cases where multiple programs of the RTO are used by a single customer (ie. Stacking).

- Consumers Energy expects to pilot new program offerings in the future as demand response matures in Michigan. The company respectfully notes that the key outcome of a pilot is learning what will or will not benefit customers and/or its operations – and that the expenses associated with pilots will not necessarily be recovered from energy savings realized during the operation of a pilot. This expectation has been noted several times within the Program and Technology Pilot Workgroup hosted by the MPSC Staff under the MI Power Grid initiative.

Please reach out to me if there are any questions,

Consumers Energy
Count on Us

Antonette Noakes
Regulatory Affairs
Phone: 517-745-7712
WORLD CLASS PERFORMANCE DELIVERING HOMETOWN SERVICE

Consumers Redlines to Draft Report

Executive Summary

On October 17, 2019, the Michigan Public Service Commission (MPSC) launched MI Power Grid in collaboration with Governor Whitmer. MI Power Grid is a customer-focused, multi-year stakeholder initiative intended to ensure safe, reliable, affordable, and accessible energy resources for the state's clean energy future. The initiative is designed to maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses. MI Power Grid encompasses outreach, education, and changes to utility regulation by focusing on three core areas: customer engagement; integrating new technologies; and optimizing grid performance and investments. The MPSC maintains a dedicated website for the initiative at www.michigan.gov/mipowergrid.

MI Power Grid seeks to engage a variety of stakeholders, including utilities, energy technology companies, customers, consumer advocates, state agencies, and others, in discussions about how Michigan should best adapt to the changing energy industry. Stakeholder groups are formed and led by MPSC Staff. This report highlights the efforts of the MI Power Grid Demand Response Stakeholder Workgroup.

Using the Statewide Energy Assessment and its findings as a foundation, the MI Power Grid DR workgroup was tasked with finding solutions to demand response underperformance during Polar Vortex 2019. Various stakeholders were asked to present on their Polar Vortex experiences, particularly on any lessons learned or problems encountered during the event. As a result of a series of meetings, it came to light that inaccurate resource availability and a breakdown in communication processes were responsible for the majority of underperformance. However, recent tariff changes at MISO and procedural changes by the utilities have been put into place since January 2019, with the goal of addressing the availability and communication problems brought to light in the assessment.

While these modifications are welcome and necessary, the workgroup highlighted several areas to improve upon these changes and ensure that demand response is able to perform at an exceptional level. The report calls for several enhancements to the utility-customer relationship, including more frequent communication, improved customer readiness procedures, and the incorporation of new technologies to streamline interactions with the customer before, during, and after an event. The report also recommends that utilities develop three key building blocks within their DR programs: real-time metering, customer readiness and a robust software platform to manage customer interactions. To the extent that these assets have not already been developed by the utility, the report recommends exploring cost effective utility-DR service provider partnerships to take advantage of services already pre-built by these external entities.

While a strong utility-customer relationship certainly reinforces one aspect of DR performance, procedures and processes must also be in place to ensure the resource is able to perform when called upon. The report recommends that notification procedures and penalty provision be clearly articulated in each utilities' respective tariffs and also highlights several areas where standardization of these processes may provide clarity to the customer and utility alike. To ensure the physical ability of a DR resource to perform, utilities should also conduct an annual real power test or a documented simulation, taking the customer's testing burden into account when deciding between testing and simulation.

As Michigan's DR portfolio continues to expand and become more sophisticated, utilities should continue to explore multiple program options, including those in the capacity, energy, and ancillary services markets. The existing pilot process, as referred to by several stakeholders, provides a means for utilities to explore new options and provide added flexibility to their customers. To the extent that the Commission accepts the recommendations contained within, the necessary tariff changes could occur either within the general rate case process or an ex parte proceeding.

Recommendations

I. Ensure LMR availability is properly accounted for in MISO's MCS tool
II. Ensure clarity and consistency in communication processes
III. Increase DR provider interaction with the customer
IV. Explore the use of enabling technologies where feasible and cost effective
V. Direct utilities to explore DR partnerships for real-time metering, customer readiness, and a centralized platform
VI. Require an annual documented simulation, encourage real power testing where feasible
VII. Formalize and standardize the notification procedure and penalties in utility tariffs
VIII. Any necessary tariff changes should be made in a general rate case or an ex parte case
IX. Enable DR value stacking

Introduction

The Michigan Public Service Commission (MPSC or Commission) issued an Order in Case No. U-20628 on September 11, 2019, that directed Staff[1] to convene a workgroup of utilities, regional transmission operators (RTO's), Demand Response (DR) providers, customer advocates, and other interested stakeholders to review and discuss the information contained in the final State Energy Assessment (SEA) report regarding the reasons for the poor response of Load Modifying Resources (LMRs) to the 2019 Polar Vortex, and to discuss ways to improve future LMR participation and performance when deployment is required.

The Commission stated that the four objectives of the group would be as follows:

1) Ensure LMR participation and performance
2) Maximize the value of DR resources in wholesale markets
3) Improve communication with LMRs during times when their deployment is necessary
4) Discuss other issues related to DR as appropriate to achieve the Commission's overarching goals of reliability and resilience.

To achieve these objectives the Commission directed the workgroup to review DR Tariffs for consistency and clarity regarding LMR deployment, consider how retail DR offerings can be better aligned with wholesale markets, examine communication procedures during DR events, and discuss ways to conduct testing of the communication and response system. Staff used these guidelines to prepare content for a series of stakeholder meetings, as described below.

MI Power Grid Demand Response Stakeholder Workgroup

The development of the MI Power Grid Demand Response Stakeholder Workgroup was a task approached methodically and deliberately. The internal DR team compiled a list of potential stakeholders that stemmed from the listservs and attendance sheets from the DR Aggregation workgroup held in 2019 and held individual meetings with the entities specifically called out in the Commission's Order in Case No. U-20628 to develop a comprehensive listserv for this MI Power Grid DR Stakeholder Workgroup. The Commission Staff worked with the Commission's Communication Division to create a webpage[2] with additional opportunities for interested stakeholders to sign up for the listserv. There are over 800 subscribers to the MI Power Grid DR listserv.

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[11] Commission Staff involved in this initiative consisted of an internal Demand Response Team, the team is cross divisional staffed with subject matter experts.

[2] Webpage here.

Staff conducted a total of four stakeholder meetings over the course of a four-month period. The meetings included presentations related to the September 11, 2019 Commission Order U-20628, the SEA report, LMR operations, communications and testing, wholesale and retail tariff alignment, and DR aggregation. The participation was outstanding with over 30 different stakeholder entities represented.

Overview of DR Stakeholder Engagement Activities

State Energy Assessment (SEA)

Governor Whitmer requested that the Commission review the supply, engineering, and deliverability of Michigan's natural gas, electricity, and propane, ultimately resulting in the SEA report. The Commission was also requested to review other areas, one of which was Demand Response performance during the weather event dubbed Polar Vortex 2019 (PV19). In the Electric Recommendations section of the Report (See 9.3.1.1), several recommendations were focused on improving DR. Some customers did not respond as required per their interruptible tariff as expected. Upon investigation it was determined that there was inconsistent tariff language. As a result, several recommendations were made to improve DR programs (See E-1). Some of the other DR-specific Electric Recommendations included a review of the electric utility tariffs for consistency and clarity (See E-1.1), coordination among utilities, Staff, and stakeholders (See E-1.2), and recommendations to utilities to review their communication plan for efficient response during emergency events (See E-1.3).

Polar Vortex 2019 Overview

PV19 took place on January 30 and 31, 2019 resulting in temperatures in the upper Midwest that dropped below -25°F. On the Bulk Electric System, frigid temperatures caused unplanned equipment failure in parts of the Midwest region, which decreased expected electric generation to levels below the amount needed to maintain reliability. As a result, a system-wide (15 states) electric emergency was declared by the RTO, Midcontinent Independent System Operator (MISO), that required: 1) all available generation to provide electricity at maximum emergency capacity; and 2) certain entities to reduce demand according to applicable emergency tariffs. In response to this emergency declaration, Michigan's electric utilities required customers on interruptible rates to immediately reduce their electricity usage. Although the electric emergency was a regional event affecting both Michigan and surrounding states, Michigan was a net exporter of electricity during PV19, providing support for the region-wide emergency.[3]

MISO, the utilities, *third-party* DR *service providers* ~~aggregators~~, and customers were asked to share their PV19 experiences at the workgroup meetings, particularly with regards to operational

[3] Michigan Statewide Energy Assessment

challenges encountered during the event as well as any gaps in communication procedures. Based on the presentations and discussion, each entities' respective experiences are summarized below.

MISO and its members were able to reliably serve load during PV19, yet some members had uncertainty in both load and supply, which created challenges throughout the event. Between January 29th and January 30th, MISO saw a 10 GW increase in outages, then additional outages prompted the move to a Max Gen event, step 2a/b to access LMRs. PV19 was the first time MISO had deployed LMRs in their North and Central Regions, with 75% of scheduled LMR MWs responded to the emergency. For MISO's Zone 7, which includes most of Michigan's lower peninsula, 67 LMRs were deployed and 74% of the MWs were delivered versus what was requested by MISO. For Zone 2, which includes Michigan's Upper Peninsula and the Eastern half of Wisconsin, 22 LMRs were deployed and 80% of the MWs were delivered versus what was requested by MISO. After a system emergency, MISO conducts a post-event evaluation of each registered LMR to assess their performance and determine any necessary penalties. A MISO Market Participant (MP), the entity who supplies the DR to MISO, is required to submit meter data for the LMRs within 53 days after the operating day of the emergency event. MISO then assesses each LMR's performance based on the meter data submitted. MISO then contacts each MP once the evaluation is completed to set up a call to confirm and discuss results. Penalties are assigned to each LMR based on their metered performance with some LMRs being disqualified as a Planning Resource if their performance was substandard. The overall LMR penalties assessed for all of MISO North and Central Regions were $1,900,000 for underperformance and an additional $900,000 due to disqualification of 18 LMRs.

DTE Energy (DTE) received the MISO directive on January 30th, 2019 to interrupt LMRs and promptly sent interrupt notices to its customers. DTE notified their customers within 35 minutes and the customers were given 1 hour and 45 minutes notice to interrupt. The tools in which DTE used to notify customers were a phone call and automated message. Direct load control (water heaters) were called at 8:00 am and then an hour later at 9:00 am, all other interruptible DR was also called. Representing a large percentage of the total DR registered in MISO, DTE thought that it did fairly well in response to the event. DTE conducted a post event review that resulted in improvements to its LMR processes based on results from PV19. DTE implemented some new communication processes, which include improved notice to the MPSC, modified message templates to indicate an actual system integrity event, internal direct communication to executives, improved existing process documents, and created specific talking points for its customer service department. DTE has additional improvements planned for the future. These future improvements include the development of SMS text options and conducting process improvements to a 3-hour historical average that will align with MISO's Metering and Verification (M&V) process of 10 day rolling availability. DTE is also supportive of shorter notification times for LMRs. DTE was able to provide appropriate notice to customers and reached 97% of its LMR customers. Account managers from DTE also personally called customers: DTE Contacted 240 of 380 total customers, however 312 of 575 total customer sites did not respond or did not sufficiently respond and were subject to DTE penalties. Penalties were paid immediately or via a payment plan. All customer penalty charges with the exception of one have been paid. Thirteen DTE customers have requested rate changes as a result of PV19. Eleven DTE customers have requested an interruptible rate product since PV19. The customer feedback received by DTE discussed how messaging was not urgent enough. DTE has since reviewed and modified the urgency and clarity of their event messaging. DTE customers also felt that one hour is not long enough to shut down equipment properly. As a result, DTE is working with MISO on the possibility of a longer lead time. DTE also found that the customers' contact personnel had changed since signing up to the interruptible rate. DTE account managers and other staff now meet with each customer annually and will include plans to discuss personnel contacts going forward. DTE has also discovered that customers need assistance with load reduction planning and will use the DTE internal group to work on outreach and training for its interruptible customers.

Consumers Energy Company (CE) stated that most underperformance for its customers came from the utility's failure to communicate effectively. Some of the key takeaways that CE had were the lack of understanding of when max gen events are happening and evaluating all the ways that max gen events can occur so its operators can respond.

> Problem 1: While the CE operators had received the LMR dispatch instructions from MISO, there was a significant delay relaying those notifications to the DR customer base. This delay occurred because the emergency event processes and notifications were dissimilar to how the CE merchant operations center had trained. Consequently, some DR customers did not receive the signal to reduce load until hours later, thereby missing a significant portion of the load reduction window.
>
> Problem 2: Customers were notified of the emergency event on January 30th, 2019, but some ~~those~~ customers did not realize that there was an expectation to perform during the morning period versus the afternoon. CE communicated to MISO that it had a certain amount of load marked as available in the MISO Communication System (MCS)*; however, a portion of* ~~when in reality~~ that level of load was not available because some ~~certain~~ portions were only available during the summer via contract. This unavailability issue accounted for the largest portion of CE's underperformance. MISO served penalties on CE based on the amount of load it stated it could reduce and did not achieve. Penalties were collected from certain CE customers, but CE held most customers harmless if it was shown that there were communication errors or requirements to only respond during summer. CE *has modified processes to ensure that in the future* ~~found it important to provide the MCS with~~ accurate LMR resource availability *is within the MCS* and *addressed* ~~also discovered~~ gaps in ~~its~~ training ~~that it intends to correct. CE has begun to implement a process to input accurate LMR availability data into the MCS year-round~~. After experiencing an *actual* emergency event, CE recognized that ~~the company could receive~~ emergency communications *may be received* in multiple ways *in addition to those*~~, and these may not be the same as what its~~ operators *experienced in training* ~~trained on~~. CE is enhancing ~~communication~~ processes *in response* ~~for internal groups and implementing~~

~~improvements due~~ to lessons learned*, and* ~~that~~ do not require changes in tariffs *to perform effectively*.

Hemlock Semiconductor (HSC), a customer of CE, is the largest electric load in Michigan. HSC received the first notification at 4:58 am on January 30th, 2019 that there was going to be a Max Gen Event at 7:00 am. At 8:46 am HSC received notification from Consumers Energy of the actual event and began responding immediately. HSC has the capabilities of running at 400 MW and nominated to reduce 75 MW. HSC was able to achieve 100% compliance for its registered 75 MW during PV19. However, HSC had some issues with the virtual dashboard from CE, but had HSC engineers on staff to review the dashboard. They were concerned with operator safety during the cold weather. HSC refined its Standard Operating Procedures and developed new training scenarios. Currently HSC conducts trainings at least once a year. As a result of PV19, HSC had a loss of production and equipment damage resulting in $250,000. With regards to testing, HSC is not opposed to simulated testing or real power testing on a small scale but would prefer not to test the full 75 MW due to the heavy cost that the lost productivity would cause. In HSC's opinion, better economic price signals may be helpful to avoid a Max Gen event.

General Motors (GM) is a large customer of DTE and has been on their Rider 10 rate for more than 25 years. GM initially received event notices around 5:00 AM and was surprised to see a Max Gen event called during a winter month. In the Max Gen event, the interruption was communicated to GM through a series of calls. Both MISO and the utility called for interruption, which went to the GM Energy Manager. Then, the DTE representative followed up with a call and emailed the GM Energy Manager. GM used DTE Load Watch to monitor usage at its DTE sites and to anticipate interruptible situations. GM was able to meet the demand response reduction in part by closing down some production and sending employees home. One of the highest performing GM facilities took extreme actions due to the nature of the event and was able to shed 40% of the facility's load. GM also ran six 6 MW diesel generators to support its curtailment effort. With those efforts, along with other GM locations, GM was able to meet the interruption requirements. Some sites experienced increased gas consumption as a result of losing building heat when the electric use was cut. GM learned that it needs to work directly with plants as it reviews curtailment processes and adjust procedures for efficient reductions when called upon. GM also stated it needs to maintain strong relationships with utilities to ensure communication channels are open. GM welcomes opportunities to improve the Demand Response program offerings to better fit an industrial profile.

Voltus is an aggregator of demand response and has a unique perspective related to the PV19 and LMRs. According to Voltus, a fundamental problem with DR is that it is not called upon every day like a traditional generator. DR is a resource traditionally dispatched on peak and is required to deliver when called upon. Voltus compared interruptible rates to "flying blind", especially if the DR provider does not have real-time telemetry. While a DR provider may have these interruptible programs on the books, it is unclear which will be able to fully respond unless they are tested or used more frequently. Voltus also sees customer employee turnover causing communication problems with demand response programs on the customer and utility sides, similar to HSC and GM. One size does not fit all when it comes to DR. In recent years, FERC has restricted the ability of states to limit aggregation of Distributed Energy Resources (DER), including wholesale energy efficiency and storage, and may extend that line of thinking to DR in the future. During PV19 Voltus was unaffected because they only make their LMR's available for the three summer months.

Natural Gas and PV19

Another outcome of extreme conditions affecting the Bulk Electric System, like PV19, is a heavy strain on systems for delivery, transmission, and storage of natural gas. With the industry wide trend of retiring coal fired generating resources and increased reliance on natural gas fired electric generation, additional constraints on natural gas service further compounds emergencies for electric supply during unusual weather conditions Furthermore, the two energy system constraints produce unique challenges for customers. For example, as previously discussed, HSC was able to respond to CE's call to interrupt electric service during PV19. However, HSC was also requested to reduce natural gas load under Consumers Gas' curtailment tariff on the same day. Even if a customer has both gas and electric service from the same company, there may not be enough communication between the two utilities within the company on how combination customers should be asked to curtail each service. This represents additional support for clear communication between not only the utility and customer, but within utility industries.

Following guidance from the SEA report, the Commission directed Staff to convene a workgroup to discuss the state of natural gas curtailment. The Natural Gas Curtailment Procedures Workgroup held several conferences consisting of regulated gas utilities, representatives of gas suppliers, customer groups, and Staff. One area of focus for the gas curtailment workgroup was identifying the appropriate priority level for curtailing service to electric generators. Staff's report containing recommendations stemming from the gas curtailment tariff workgroup was issued on June 30, 2020.[4] These recommendations address communication among utilities and their customers, as well as deem electric generation essential for public health and safety as highest priority for curtailment (i.e. curtailed last, in the same category as residential customers).

LMR Operations and Communications

In addition to the operational walkthrough summarized above, representatives from DTE, CE, Voltus, and HSC were asked to participate in a panel discussion to expand upon their experiences. The panelists were asked to identify the drivers behind LMR underperformance, possible solutions, and steps taken to solve the operational and communication issues experienced during PV19. Ultimately, this conversation culminated in the creation of the 2-19 Solutions document[5], which

[4] See Case No. U-20632 or more information on the workgroup here.
[5] Posted to website here.

was created by Staff based on the panel discussion and input from other stakeholders. The panel discussion, as well as the numerous solutions identified in the document, are summarized below.

One of the primary contributors to LMR underperformance during PV19 was communication errors, either between the utility and customers or within the utility itself. In some instances, customers mistook the automated emergency notification for an economic buy through notification, which is a provision that allows the DR customer to pay a price instead of curtailing load. This caused them to ignore the signal to reduce load and continue operating as normal. Based on feedback from customers, this confusion seems to have stemmed from a lack of a sense of urgency in the automated messaging system, as the tone and voice of the emergency notification sounded similar to the economic notification.

In other instances, the customer did not receive a notification until much later in the event, causing the utility's portfolio to underperform. While the utility operators had received the LMR dispatch instructions from MISO, some customers did not receive the signal to reduce load until hours later, thereby missing a significant portion of the load reduction window. However, some customers were able to respond in full. Both HSC and GM were able to reduce loads to achieve the full nominated amount. While both companies did not expect a winter event, each attributed their successful response to training and preparation at their facilities as well as being able to communicate with their respective utilities in real time and over the course of the year. Customer/DR program readiness and communication with the utility are the most important components of a successful response to a Max Gen event.

Taken together, these positive and negative experiences highlight the importance of clear, consistent messaging, so that customers are able to understand how to respond during economic and emergency conditions. Notification language and tone for an emergency event should sound and look different than economic notifications, in order to elicit the appropriate customer response. This communication should occur across a variety of platforms, such as automated message, telephone, and text in order to more easily reach customers while also taking into account the customer's preferred communication medium. Additionally, multiple personnel contacts for each customer site should be on file to reduce the number of unreachable sites. Since January 2019, utilities have made progress towards several of these items, including improving notification language, clarifying performance expectations, and considering new ways to notify customers of an event. In addition to appropriate messaging, the frequency of customer communication is a key component to ensure that the customer can respond when called upon.

Currently, LMRs are rarely called[6], but are expected to respond in full when they are needed, often backed up by the threat of penalties for underperformance. As most customers are not heavily

[6] January 30, 2019 was the first time MISO deployed LMRs in its North and Central regions in the history of its market. Slide 56

engaged in the energy industry, and primarily see DR as a way to lower their electric bill, *periodic* ~~frequent~~ contact with their DR provider (the utility or *other third-party DR provider* ~~aggregator~~) is necessary to ensure their performance in these rare events. In accordance with current utility practice, this contact should begin upon customer enrollment in a program and followed up annually. Setting clear and consistent expectations at this stage will help ensure expected performance when an event is called. DR providers can also offer support at this time, such as the creation of a customer-specific load reduction plan. Several stakeholders stated that the customer's response improves with more frequent DR events, noting this is even more apparent for customers participating in multiple DR programs. Currently, most Michigan utilities communicate with the customer at least once per year to review customer obligations, offer assistance, and develop load reduction plans as needed. More frequent interaction is preferable as Michigan's DR portfolio expands and DR is called upon more often throughout the region.

Another potential solution identified by stakeholders was the use of enabling technologies to assist with managing the utility's DR portfolio and easing the customer's response obligation. Before utilities can make full use of these technologies, they must have a core component, *a communicating meter* ~~customer-specific metering~~. Today, most Michigan utilities have access to hourly metering through smart meters for residential customers and have access to real-time data for some commercial and industrial (C&I) customers. Several stakeholders commented that expanding real time telemetry is the key to unlocking further DR potential, particularly as DR programs grow. Proponents of real-time metering suggest this is particularly important for C&I loads, but in their experience ideally 75% of DR customers should have real-time metering to enable the other technology options below. This added visibility would allow DR providers to directly monitor customer response and react to actual customer performance during emergency events. The benefits associated with real-time metering will continue to accrue as distributed energy resource (DER)[7] penetration increases across the state. However, stakeholders also caution that the added benefits of expanded real-time metering should be weighed against its cost. With hourly data widely available throughout the state, the marginal benefit of real time telemetry may not justify the additional cost. *The use of the data must be considered in a review of the benefits – to assess responses after the event, real-time metering may not be required. For the relatively small number of customers requiring visibility during an event by the customer, a number of options may exist.*

Regardless of which metering interval is chosen, visibility into the customer's load is key to unlocking a variety of technologies. The technology most discussed during stakeholder meetings was a centralized DR platform designed to facilitate customer-DR provider communication, interaction, and reporting. To begin chronologically, a centralized software platform would

[7] See NERC's 2018 definition of DERs, which does not include DR. Other entities, such as MISO, include DR as part of the broader DER definition.

automate many of the notification tasks that are required when a DR event begins. This would enable DR providers to notify customers within 5 minutes or less, if not immediately. As noted above, a quick notification turnaround from the RTO to the DR provider to a customer is essential to timely performance within the event window. As the DR event begins, the software platform would take customer data as inputs to evaluate individual and portfolio-wide performance in real time. This would allow utility operators to quickly identify and address underperformance at specific sites during a DR or emergency event. Ideally, the platform would allow both the customer and DR provider easy access to customer baselines and energy reduction plans already on file that operators could use to make personalized calls to customers and recommend actions in real time. This 'performance coaching' could address performance issues that can be quickly solved in real time, helping customers and the DR provider avoid performance penalties. Lastly, a centralized platform could assist with post-event communication and reporting. The system could immediately send out a notification when the event has ended, allowing customers to get back online sooner and possibly avoid additional costs. Within a couple days after the DR/emergency event has ended, the system could generate preliminary performance reports which could be personalized and sent to each customer. These reports would help each customer understand how they performed and would add an additional level of transparency and communication to the process. Stakeholders mentioned such post-event reports are common outside of Michigan and already exist today, including reports created by third party aggregators and equipment manufacturers. To the extent that utilities do not already possess a robust centralized software platform with the above capabilities, *partnerships with* third-party *service providers* ~~DR partnerships~~ may be an efficient way to increase reliability, transparency, and customer interaction as some companies have already invested in and have developed their own platforms.[8] The utilization of a software platform can assist with multiple aspects of DR registration, deployment, and reporting, stacking the value delivered by such a tool.

Wholesale and Retail Alignment

Overview of Regional Transmission Operator (RTO) programs and recent rule changes

At the March 17th, 2020 stakeholder meeting, MISO and PJM were asked to provide an overview of each region's DR products, including how a DR resource's performance is measured and any recent rule changes, with an emphasis on those that have changed since January 2019. MISO explained that DR can be used in four distinct ways: as an economic, operating reserve, planning resource, or emergency only product. MISO has multiple DR registration options where qualifying resources can register as a Demand Response Resource (DRR), Load Modifying Resource (LMR),

[8] See Ameren-Enel X partnership here, where Enel X's customer platform allows for real time monitoring and optimization.

Emergency Demand Response (EDR), or dual-register in any combination of the above.[9] Upon registration, a MP has the ability to select how it would like its DR resource's performance to be evaluated. MISO's performance evaluation options are as follows: Firm Service Level (FSL), Meter Before/Meter After, Baseline Type-I, Baseline Type-II, and Metering Generator Output.[10] Each of these options has benefits and drawbacks which a MP must weigh based on the unique characteristics of each DR resource or program. For the purposes of this stakeholder group, the FSL and baseline approaches are the most relevant, especially as to how they incentivize customers to behave, as discussed in the Value of DR section below. As MISO explains, the FSL approach requires load to drop to a certain level, regardless of the current level of load. This is often referenced as the 'reduce to' approach. The baseline approach requires load to drop by a specific amount below the current load, the 'reduce by' approach. The MP can adjust how they would like their resource's performance to be measured on an annual basis.

MISO also compared how its market rules changed between January 2019 and Spring 2020. MISO's new notification and availability rules became effective February 21, 2019[11] and require documentation for resources with greater than or equal to six hours notification time or less than or equal to six months of availability. Documentation types include an attestation to the LMR's capabilities, a description of LMR operational characteristics, and regulatory/contractual limitations per MISO Business Practice Manual (BPM) 11, Section 4.2.8-4.2.9. These tariff and BPM requirements reduce the resource's notification time and increases the resource's availability, until reaching a notification time of two hours and availability of nine months, where no documentation is required.[12] Additionally, MPs must submit monthly availability in the MCS. These changes are intended to reflect a resource's true capabilities in order to give the operator more visibility and information when calling upon these resources. For example, if a resource is only available during the three summer months, those are the only three months when the MP inputs the data into the MCS. The Organization of MISO States (OMS)[13] and other MISO stakeholders were generally supportive of these changes. Recently, MISO has filed a proposal to further restrict these rules and is linked to the LMR accreditation filing discussed below.

The second set of market rules that changed between PV19 and Spring 2020 are MISO's new testing rules, which became effective June 1, 2019.[14] Previously, LMR testing was not a requirement to register as a LMR in MISO. Under the new tariff changes, testing is required for the full accredited amount of an LMR. Alternatively, the MP may opt of out testing and accept a

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[9] See March 17th materials, Slide 11, for a visual representation of all eight DR registration options.
[10] Ibid., Slide 12 for a detailed description.
[11] See ER19-650, which was filed December 21, 2018.
[12] See March 17th materials, Slide 14-15 for a comparison of MISO's rulesets.
[13] OMS comments.
[14] See ER19-651, which was also filed December 21, 2018.

three-times penalty in the event of non-performance, pending any regulatory restrictions on testing. This filing was submitted simultaneously with the LMR availability tariff filing above and is intended to allow MISO to more effectively assess the capabilities of LMRs they rely on to maintain the reliability of the grid. As with the availability ruleset above, the OMS[15] and other MISO stakeholders were generally supportive of both of these tariff changes.

Both the LMR availability and LMR testing tariff changes are part of MISO's ongoing, multi-phase Resource Availability and Need (RAN) initiative.[16] This initiative has continued into 2020, and has resulted in another rule change, this time to LMR accreditation, filed May 18, 2020 with the Federal Energy Regulatory Commission (FERC).[17] Under the proposal, starting in the 2023/24 Planning Year (PY 2023/24), LMRs would need to be able to respond within six hours or less to qualify as an LMR, down from the twelve hour notification time in the 2019 FERC tariff filing above. In addition, LMR capacity credit would be prorated based on the number of calls a resource is able to respond to in a given planning year. Ten or more calls will be required for 100% capacity credit and five to nine calls would receive 80% capacity credit. LMRs with availability less than five calls would not be eligible to receive capacity credit. Behind the Meter Generation (BTMG) resources registered as LMRs would continue to receive 100% capacity credit, provided they are able to meet the six-hour notification time and five to nine yearly call requirements. These BTMG resources will continue to be subject to further adjustment based on their outages and derates, making the capacity credit BTMG resources receive more aligned with the reliability value they are providing.

In response to MISO stakeholder feedback, these requirements will be phased in during the PY 2022/23, with some added flexibility for LMRs that cannot comply with the six-hour notification requirement. During PY 2022/23, LMRs with notification time greater than six hours, but less than twelve hours, will receive 50% capacity credit as long as they are available for a minimum of ten calls that year. Starting in PY 2023/24, all LMRs must meet the six-hour notification time in order to receive capacity credit. In conjunction with the 2019 LMR filings, MISO's accreditation proposal is intended to enhance the accessibility of LMRs during emergency conditions, improving flexibility and aligning LMR capacity credit with the services they can provide. While this accreditation proposal has not yet been accepted by the FERC, the OMS has filed supportive comments, particularly considering MISO's accommodation of a transition mechanism and additional leeway for LMRs that cannot respond within six hours or less.[18]

Primarily using the information in the Module E Capacity Tracking (MECT) Tool, MISO estimates that the LMR accreditation proposal will reduce Zone 7's (Michigan's lower peninsula) LMR

[15] OMS comments.
[16] More detail on the RAN initiative here.
[17] See ER20-1846.
[18] OMS comments here.

capacity credit by 795 MW and Zone 2's (Michigan's upper peninsula + eastern Wisconsin) LMR capacity by 40 MW, assuming no action is taken by the MPSC or utilities.[19] For reference, Zone 7, which represents most of the lower peninsula of MI, currently has about 2200 MW of LMRs. Zone 2, which encompasses the Upper Peninsula and parts of Wisconsin, currently has about 360 MW of LMRs in the Upper Peninsula, exclusive of any LMRs in Wisconsin.[20] According to MISO, Zone 7's total impact is split between 285 MW of DR and 510 MW of BTMG resources.[21] In discussions with Michigan utilities, municipalities, and cooperatives, MPSC Staff has further broken down these estimates among the various entities. Consumers Energy estimates a 175 MW reduction and DTE estimates a 100 MW reduction[22] to their current LMR accreditation, per MISO's methodology. This leaves a remaining 520 MW impact in Zone 7, which will likely come from BTMG generators owned by non-MPSC regulated entities. Michigan Public Power Agency (MPPA) stated the six-hour lead time requirement would have a significant impact on several of their members' BTMG units, at least 130-150 MW as a verbal estimate on March 17th. From a cold start condition, the six-hour notification time would be difficult to meet without damaging the BTMG unit. Thus, MPPA highly supports a two to three year transition to give its members time to make changes to their units. MPPA also suggested that disqualifying units above the six-hour notification time seems paradoxical to the goal of having more MW available to combat emergency event conditions. MISO's latest revision addresses some of these concerns, by adding an additional year of transition time for BTMG with above six hours, but under 12 hours lead time. Per MISO's description above, it is important to note that these estimates assume no change is made and consequently are expected to be well above the true impact. Pending FERC's acceptance of the filing, these entities will have until PY 2022/23 to make the necessary changes in order to continue to receive full capacity credit before this LMR accreditation tariff change is fully implemented in PY 2023/24.

While PJM was not as affected by PV19 and did not experience the level of operational issues as MISO, Staff asked PJM to provide an overview of their DR products, with an eye for any improvements made since PV19. Generally, the PJM footprint relies more heavily on Curtailment Service Providers (CSPs), third-party *DR service providers* ~~aggregators~~ and/or utilities, who provide DR services to the customer. PJM's DR products are broken down into two categories: emergency and economic. Emergency, or load management DR, is able to participate in the energy and capacity market. Economic DR, like the MISO products, is able to participate in the energy and

[19] See MISO's filing in ER20-1846, pg. 14.
[20] Per U-20590.
[21] See "MISO Estimate of LMR Accreditation Impact- Zone 7" table in Appendix

[22] See "LMR Accreditation Impact to DTE" table in Appendix. Also see Overview of utility programs section below.

ancillary service markets when it is economic for those customers to do so. MPs can dual-register for any of the options above. PJM also offers two demand side products, Price Responsive Demand (PRD) and Peak Shaving Adjustment (PSA), which allow load serving entities (LSEs) to reduce their capacity commitment. PJM offers two performance evaluation options; however, the vast majority of participants chose the FSL approach, the 'reduce to' method referred to above. PJM also offers a 'reduce by' approach, the Guaranteed Load Drop method, but this is rarely used. For each of these approaches, CSPs must submit 24 hours of actual hourly load data after a load management event occurs. PJM's DR resources performed as expected during PV19 and thus no tariff changes have occurred, with the exception of new load management testing requirements, filed April 12, 2020.[23]

Currently, if the resource is not dispatched during a Delivery Year, DR customers are required to perform an annual test of one hour for the entirety of the registered MW. The test is scheduled by the CSP with an unlimited ability to retest. As PJM notes, historically this has caused test performance to be greater than event performance. This test is not currently compensated and is subject to a nonperformance penalty of the revenue received by the underperforming MW, plus the higher of $20 or 20% of that revenue. PJM's new requirements are currently before FERC in a tariff filing and would require an annual test, scheduled by PJM, with a duration of two hours. Testing would be scheduled by each Transmission Owner zone, which would rotate monthly, ensuring DR resources would be tested across all seasons as the delivery years progress. If the DR resource can achieve greater than 75% of its registered MW in the initial test, the CSP may schedule an unlimited number of retests to improve their score. However, if a resource achieves under 75% during its initial test, a retest can only be scheduled with PJM during the same season to improve their score. With this more rigorous testing regime, CSPs would be paid for their energy reduction at the Locational Marginal Price (LMP) for the duration of the test event. PJM proposes an effective date of June 16, 2020, pending FERC's acceptance of the filing.

Overview of utility programs and response to changing RTO rules

During the March 17th, 2020 panel discussion, utilities were asked to provide an overview of their DR programs and any actions taken in response to the changing RTO rules above. CE reported that all of its DR programs are registered as LMRs, with the exception of Dynamic Peak Pricing (DPP). Since DPP is a hybrid program, where interruptions are combined with a time of use rate, CE reflects this load reduction in its load forecast, rather than an explicit registration at the RTO. LMRs provide CE with capacity credit and this registration is aligned with the program's use as an emergency only resource *in the case of the current C&I portfolio. The residential programs that CE registers as LMR's have the ability to provide economic dispatch as needed*. CE's residential

[23] See ER20-1590.

programs are registered using a baseline performance evaluation methodology while most commercial and industrial programs use a targeted load reduction. The exception is C&I Rate GIQ, which uses a firm service level approach. With regards to LMR availability, CE will continue to provide documentation to MISO, recognizing that not all DR (like AC cycling) can be available year-round. Since PV19, CE has corrected the availability information input into the MCS, which was the primary driver for its underperformance. With regards to testing, CE indicated that it does not plan to require a real power test from their customers, and instead will provide historical information to MISO and attest to the performance capabilities of their DR portfolio. Per MISO's rules, CE can opt out of testing but would be subject to a three times penalty in the case of underperformance, which the utility accepts.

With regards to LMR accreditation, C&I DR would be most impacted. CE expects a 175 MW reduction to its LMR capacity accreditation, assuming no changes are made. This reduction results from certain DR programs that are *currently* not able to meet the 10+ call limit. *The first impact would be to the* CE Rate GI. *The tariff language* does not currently specify a call limit and likely accounts for a portion of this impact *as the registration in to the MISO MCS system limited the calls to 5 per year. Updating* Rate GI's resource availability ~~would simply need to be updated~~ in the MCS *would allow the capacity to fall into compliance with the proposed tariff changes at MISO*.

In the C&I DR Program, CE enters into contracts with these customers, most of which are multi-year contracts that ~~are~~ *can be* up to four years in length. CE negotiated these contracts based on the current MISO tariffs to ensure that the required interruptions specified by the contract are aligned with the current tariff and do not require the customer to be available for ten or more calls per year. CE would *need* ~~be able~~ to renegotiate these contracts going forward *for compliance or* ~~but~~ could lose about 118 MW of capacity credit for their contracts if MISO's tariff change were effective immediately for the planning year 2021/22. To mitigate the impact of MISO's tariff changes on its C&I DR program, CE has advocated for a three-year transition time, which would give the utility time to make the necessary changes and renegotiate its contracts.[24] CE does not expect to be impacted by the six-hour lead time rule change *for the DR programs registered as LMR resources*.

Similar to CE, all of DTE's programs are registered as LMRs with the exception of retail rate tariff DPP and Rider 12. DTE is considering shortening the notification time of their DPP rate in order for the rate to qualify for capacity credit at MISO. This change may occur by the 2022 capacity auction, pending testing and customer reactions. Rider 12, which pays C&I customers for their interruptible capacity, was marketed in 2019 to customers. DTE registered this rate as an LMR at MISO in 2020. With regards to LMR availability, DTE is again positioned similar to CE. DTE will continue to provide documentation to MISO, recognizing not all DR programs will be available

[24] See Consumers ER20-1846 Comments.

year-round, and will continue to update the MCS with hourly availability. With regards to testing, DTE would only require real power testing for Direct Load Control customers. While still weighing the benefit/cost, DTE would likely opt out of the testing requirement and accept the increased penalty for nonperformance. DTE expects no impact to its registered LMR due to changes in DR accreditation by the time MISO's new tariffs go into effect. The 100 MW estimated impact in MISO's methodology is accounted for in the DTE Rider 12 contracts, which can and will be updated annually. Most of DTE's remaining programs do not have call limits[25] and the utility does not expect any issues with the requirement of more call times. DTE supports the MISO proposal and is not opposed to a transition time.

Indiana Michigan Power Company (I&M) has 135 customer accounts footprint wide, representing 82 MW, registered at PJM as an emergency resource. I&M also offers a C&I customer specific interruptible program, which is not registered at PJM. The vast majority of I&M's DR customers use the firm service level performance methodology as described above. With regards to DR availability, I&M noted that there are three different lead time options for PJM emergency DR: 30, 60, or 120 minutes. These programs provide the customer with more options, and I&M has no concerns with this approach. With regards to testing, I&M is already required to perform an annual real power test, per PJM's rules. I&M is supportive of PJM's new testing proposal, as they seem reasonable and better mimic actual availability during a DR emergency event.

Testing

As referenced in the Wholesale/Retail Alignment section above, MISO's tariffs regarding testing changed June 1, 2019 to require a real power test or accept a higher penalty in the case of nonperformance.[26] During panel discussions at the February and March 2020 meetings, stakeholders were asked about the merits of requiring a real power test or opting out in favor of a heightened nonperformance penalty.

CE stated it would not require a real power test and would instead provide historical information to MISO to attest to LMR performance capabilities. However, CE noted customers do have the option to conduct a 30-minute dispatch readiness test to help them prepare for an event. *On an annual basis and in coordination with the customers,* CE ~~would~~ simulates a DR event and monitors the customer's performance, giving the customer valuable feedback in a real-world setting. Should the customer fail to achieve at least 70% of their registered MW, CE would follow-up after the event to better understand any performance issues and potentially update the energy reduction plan on file. To the latter point, before signing up a customer on a DR program, *CE* ~~Consumers~~ creates an energy reduction plan for each specific customer. The plan includes the

[25] The Bring Your Own Device and Smart Currents programs currently have a call limit of 14, which earn them full capacity credit under the new MISO methodology.
[26] See ER19-651, which was filed December 21, 2018.

MW reduction nominated, type of affected equipment, shutdown procedure, and load reduction for each piece of equipment. CE uses this information to assess whether the stated reduction is viable and works with the customer before signing them up on the *program* ~~rate~~.

DTE had a similar response to CE and only expects to perform real power tests for its Direct Load Control customers. For the remainder of their LMR customers, DTE is currently analyzing the costs/benefits of requiring a real power test. DTE polled its interruptible customers to gauge the impact of a real power test and whether that would impact their decision to remain on the rate. DTE's initial finding suggest that the cost and inconvenience of testing would be high. Consequently, the utility is leaning towards accepting the increased nonperformance penalty, while continuing to provide all necessary documentation to MISO. DTE also noted its annual LMR readiness process helps ensure all interruptible customers are aware of their obligations and notification process if a DR emergency event is called. DTE annually sends out reminders via letter, notifies customers of any test date if applicable, and verifies contact information ahead of the summer season.

Voltus, a DR aggregator, pointed out that most other RTOs, including PJM, IESO, CAISO and ERCOT, already require an annual real power test and that MISO is an outlier in this space. When Voltus tests their own customers, it works with the customer to perform the test in the least disruptive manner possible. Voltus notes that if testing is required, it should also be properly valued, whether that be through a capacity market payment or a line item for testing. In the absence of compensation, testing can be quite onerous for some customers, leading them to rethink their level of commitment or to simply not participate.

The Foundry Association of Michigan reported that real power testing would be very deleterious to its members. Testing, would mean an interruption in heavy industrial processes, leading to an economic loss in the form of loss of product at a minimum or possible equipment damage. Depending on the situation, this loss could be substantial, up to tens of thousands of dollars. Compensation for testing, outside of a reduced rate, would likely not be enough to cover these costs. Instead, the Foundry Association indicated its willingness to participate in a tabletop exercise to demonstrate its facilities' ability to drop load in emergency conditions.

Hemlock Semiconductor (HSC) echoed the Foundry Association's thoughts above. HSC was able to fully perform during PV19, when testing was not required, due to robust operating procedures and documented simulations. HSC suggests that these could be submitted in lieu of a real power test. If a real power test would be required, HSC would prefer to be able to test a portion of its load, instead of the full registered amount. HSC explained that in addition to losses incurred during the test, their facility would take several days to ramp back up to full production after an event. This would compound the economic losses and make testing compensation inadequate.

Entities in PJM, like I&M, are already required to conduct an annual real power test for their emergency DR resources. PJM has attempted to strike a balance between performance and customer compensation by paying participants based on the LMP for the testing hours. While this option has not been pursued at MISO, stakeholders have suggested that compensation for testing should be evaluated on a program-by-program basis if attempts were made to compensate at the retail level.

In summary, most stakeholders prefer simulation only, in lieu of a real power test. Most also agree that specific compensation for testing would likely be inadequate to cover costs. Instead, testing, if required, should be properly valued by the capacity market or retail rate.

DR Value Streams

Economic vs. Emergency Resource

An underlying theme throughout these stakeholder meetings was the need to investigate ways to maximize the value of DR, particularly as an emergency resource but also as an economic resource where appropriate. While most of the value currently comes from the capacity construct, particularly in MISO, DR is also able to participate as an economic resource, via the energy and ancillary markets. Voltus, which has a footprint across the United States, noted the importance of value stacking, as seen in other markets. DR providers are able to combine the traditional capacity value of DR with other RTO products, as well as peak shaving on the customer level. A diversity of program offerings at the retail level could facilitate this value stacking and open the door to dual-registration at the RTO level.

However, as the utilities noted, different program options have been offered in the past, but customer interest was lacking. CE stated that its C&I contractual program *has and continues to* ~~did~~ offer an economic option for *customer participation. In 2018, approximately 18 MW participated in the economic program. In 2019, that amount was approximately 7 MW. In the 2020 MISO planning year, there are currently 0 customers / MW's that opted in to the program. CE has and will continue to offer an economic dispatch option for their customers in the C&I DR contract program. To date, for planning year 2021, the company has not had a customer enrollment at an offer price of $75/MWh.* ~~several years. However, customers did not opt-in to the program at high enough levels to move it out of the pilot stage.~~ HSC described its struggle to see how it could operate with stacking emergency and economic events. Clarity around how these events would interact, and which would take priority is needed for HSC to explore dual-registration further. DTE is also testing the concept of offering an economic option via Rider 12. While in the initial stages, DTE's concern is that economic events are called more often, which may lead to greater levels of customer attrition. This impact appears to be less for residential customers. DTE currently dispatches these customers for economic reasons under its air conditioning (AC) cycling programs. CE, DTE, and I&M are open to exploring value stacking further and indicate that this may be best completed via the pilot program process.

In conclusion, DR programs must provide value to both the utility and customer. Enticing customers to sign up for multiple DR programs will require an additional level of marketing and communication, in order to ensure the customer understands each program, any interactions, and what value dual-enrollment would provide to the customer. As the need for grid flexibility grows, the value of DR will _need to_ increase _at the wholesale market level in order_ for both utilities and customers _to participate in DR programs_.

Performance Obligations and Unintended Incentive

The panel discussions on February 19th and March 17th included the idea of a potentially unintended incentive embedded in some DR registrations. The applicability of this incentive is largely dependent on how a DR resource's performance obligation is measured.[27] Upon registering the resource at the RTO, the DR provider can choose which measurement and verification (M&V) protocol the resource will be subject to. Most M&V protocols can be classified into two buckets: a 'reduce by' (targeted reduction) or 'reduce to' (firm service level approach). Under the 'reduce by' approach, a customer has the incentive to increase or maintain load just before an event, thereby allowing for the customer to meet its MW reduction target more easily. If deployed en masse, this incentive may not align with the needs of the system during an emergency event, where less energy consumption overall may better ease system conditions. Stakeholders noted that if a 'reduce to' approach was used instead, the customer would be able to ramp down earlier and more gradually, perhaps also allowing the customer to extend the duration of the reduction. This option may grant additional flexibility to customers who favor a slower ramp down to avoid damage to their equipment. Other stakeholders cautioned against mandating one approach over the other. Each performance methodology has pros and cons, so stakeholders suggested studying a small group of customers to understand any unintended consequences before making further changes.

DR Aggregation

While DR aggregation was the focus of Case No. U-20348 and the 2019 stakeholder group,[28] the outcome of that proceeding and ongoing action items are relevant to the Commission's overarching reliability and resilience goals in Case No. U-20628. Thus, Staff reviewed the outcomes of U-20348 that provided an overview of MPSC processes related to DR aggregation. The proceeding also coordinated informational updates from MISO, the Advanced Energy Management Alliance (AEMA), Michigan utilities, and the National Regulatory Research Institute (NRRI).

To start the discussion _on aggregation, it is important to note that the Commission's orders in Case No. U-16020 and again in Case No. U-20348 limit the ability of aggregators within Michigan to participation with retail open access customers. Aggregators of Retail Choice (ARC's) are not allowed to enroll, either directly or indirectly, a utility's retail customer._

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[27] See March 17th materials and above for a description of each of the performance evaluation methods.

[28] More information here.

At the meeting on March 17, Staff provided an overview of the capacity demonstration process, focusing on how aggregated DR is represented. Currently, aggregated *retail open access customer* DR represents about 71.4 MW in Michigan as evidenced by the 2020 capacity demonstration filings. Staff noted that as participation in aggregated DR increases *for retail open access customers*, the need for communication between the MPSC, the incumbent utility, the Alternative Electric Supplier (AES), and the DR aggregator *also increases* ~~becomes increasingly more important~~. This particularly holds true for any DR dispatched on MISO's peak, which has the potential to change a customer's Peak Load Contribution (PLC) and must be properly accounted for in MISO and MPSC processes.[29]

Pursuant to the Commission's direction in U-20348, Staff continues to advocate for changes to address this PLC issue at MISO,[30] primarily focusing on information flow and data sharing. Recognizing feedback from the MPSC and other Michigan stakeholders, MISO has proposed changes to Module E-1[31] that would facilitate needed information exchange when aggregated DR is dispatched on MISO's peak. Staff is supportive of these changes and expects them to mitigate the PLC issue above. In addition, the MPSC remains able to request this information from MISO, subject to all relevant confidentiality agreements. However, discussion at the April 28th, 2020 meeting revealed that while the AES should have access to this DR dispatch information under MISO's current tariff, the AES may not have access to this information in practice. Staff plans to investigate this matter in future discussions with MISO, the utilities, and AESs and clarify the duties of each entity.

Another key outcome of U-20348 included a focus on utilities, encouraging them to leverage relationships with DR ~~aggregators~~ *service providers to* ~~which will~~ further expand DR opportunities and/or identify options for scaling up of DR *participation* ~~aggregation~~. These utility-~~-aggregators~~ *DR service provider* partnerships could come in the form of a full turn-key solution, where DR ~~aggregators~~ *service providers* acquire and manage DR customers on behalf of the utility, or a limited contractual arrangement where the utility is able to make use of a~~n~~ third-party's enabling technology or software platforms to help manage the utility's DR portfolio. AEMA, whose members include DR ~~aggregators~~ *service providers*, suggested that DR providers should have three key capabilities that are essential to DR program reliability and success: 1) sufficient ~~metering to provide~~ visibility into customer load (75% of portfolio to effectively manage the portfolio), 2) robust customer readiness procedures, and 3) a centralized portal that allows utilities

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[29] See the 2019 DR Aggregation Staff Report for a full description of this issue.

[30] See MPSC feedback to MISO's Markets Subcommittee here, here, and here.

[31] Proposed Module E-1 changes here. The proposed language would require MISO to provide the Electric Distribution Company (EDC) the amount of measured load reduction that occurred as a result of an aggregator deploying demand response during the MISO coincident peak.

to analyze, monitor and coach customer performance during events.[32] To the extent that utilities do not already possess these capabilities, partnering with a third-party *utility service* provider may be an efficient use of ratepayer dollars as compared to developing such assets in-house. To facilitate these partnerships, AEMA suggested that the MPSC could provide additional direction to better align spending with the MPSC priorities stated in Case No. U-20348. To this end, the MPSC could direct utilities to incorporate the above capabilities into their DR programs, taking advantage of existing third-party *utility service* provider capabilities as *deemed* necessary and prudent *by the utility*.

Staff invited CE, DTE, and I&M to provide an update on any DR provider partnerships and how the utilities plan to build these partnerships in the future. CE and DTE do not make use of full turn-key solutions with DR ~~aggregators~~ *service prov[33]iders*. *Such providers* ~~Rather, the utilities partner with third parties to~~ assist with monitoring, customer portals, or other technologies *that are not core competencies of the utility internally. These third-party utility service providers are contracted by the utilities themselves and provide program support, marketing expertise, customer enrollment, installation services and ultimately capacity for the utility at a negotiated price. This allows a utility to leverage the expertise of companies with core competency in delivery of these programs. These third-party utility service provider relationships are established and validated through utility rate case filings, cost of service methodologies, levelized cost of capacity analysis and the IRP process to assure they are a cost-effective means of delivering benefits of DR resources to everyone. These resources, as applied in an IRP plan, provide value to the participating customer in an incentive payment or lower rate, value to the utility in avoided capacity purchase or acquisition and a value for all utility customers in avoided generation costs.*

CE reported that they currently use third parties to assist with real-time monitoring as well as to run the customer portal. Both of these functions work in unison to provide data to the customer dashboard and enable the utility to respond in real time. CE expects to continue to explore DR partnerships *with utility service providers* in the future and sees the pilot process as particularly helpful in this regard as it gives the utility the flexibility to explore new opportunities outside of the typical rate case process. DTE currently uses DR partnerships to manage its smart thermostat and SmartCurrents programs. DTE's partners provide marketing and platform support, which allows DTE to take advantage of external expertise in those areas. Apart from the Load Watch

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[32] See LMR Operation and Communications section above or April 28th meeting materials for more detail on these points.

[33] There is a distinct difference between an "aggregator" and a "DR service provider", as well as a "third-party utility service provider". A DR service provider may provide services to a utility or directly to end-users. A "third-party utility service provider" work through a partnership with a utility and provides clearly defined services. An aggregator specifically works directly with end-users who receive direct financial benefits from the aggregator; for this reason, no direct benefits are realized by customers of a utility in the service territory of the end-users the aggregator is working with.

program for C&I customers, DTE relies on post-event AMI meter data to assess how customers were able to respond to DR events. DTE is open to future DR partnerships *with utility service providers*, as directed by U-20348, but notes that its plans were delayed by the current COVID-19 crisis. I&M and its parent company, AEP, has experience working with DR aggregators across several states and recently has established its first CSP partnership in Michigan. I&M will continue to work with PJM, the MPSC, and the CSP to define the partnership and its framework as DR aggregation expands in the Michigan footprint.

NRRI also spoke on actions that states have taken on DR in recent years, including DR aggregation. Several states offer pathways for non-utility providers to offer DR services. Learnings from other states indicate various levels of successes and impediments, including an increased level of DR and supporting technologies, but all have concluded that there is a greater need for data sharing and coordination. In the future, NRRI hypothesized that the incumbent utility's role and business models could change based on how DR, and other services, are structured within a particular state. Options range from an open access system, where third parties design and offer products to meet customer needs, to a system similar to today, where the utility manages program offerings and opportunities. NRRI will be exploring this and other DR policy questions as part of an upcoming paper.

Utility Demand Response Tariffs

As directed by the MPSC's Order in U-20628, Staff conducted a review of all Michigan interruptible utility tariffs, looking for areas for improvement or alignment in coordination with the ongoing stakeholder process. As highlighted during the February and March 2020 stakeholder meetings, Staff found four possible areas for improvement which are: consistency, transparency, specificity, and testing.

Broadly speaking, interruptible tariffs follow a similar arrangement across utilities. Each tariff includes information about what customers can participate, notification procedures, the penalties for non-interruption, the discount for participation on the rate, a definition of firm load, and the contract term length. Additional components that may be offered through interruptible tariffs include options to "buy-through" events, product protection fees, change interruptible load mid-season, and a variety of pricing options. In addition to tariffs approved by the Commission, utilities also offer interruptible DR programs that are negotiated between the utility and customer through contracts (e.g. CE's C&I DR Program). These contract-based programs offer the greatest flexibility by allowing the utility and customer to agree on the exact terms of their participation in DR.

The workgroup expressed interest in offering a diverse set of DR programs to customers. Options include various pricing, seasonal or year-round interruptible service, and contract length. Being too prescriptive in areas of the tariff may hinder the participation of customers with heterogenous load profiles or end-uses.

While variety in some specific aspects of interruptible tariffs is useful to customize a utility's offerings to its unique service territory, consistency across certain provisions could be beneficial to the customer. Penalties, or what the customer is charged for failure to interrupt during an event, should not vary between utilities because non-interruption does not carry a different cost depending on service territory. Because the call for emergency interruption ultimately comes from MISO, the penalty should be the same for all customers in the same MISO zone. Likewise, penalties for non-interruption should remain consistent across rates within the same utility. The interruption start window, or how long the customer has until it must reduce load following a call from the utility, should also be consistent across utilities. This way, an interruptible customer being served by different utilities at different business locations would have the same expectations of interruption during an emergency event.

The notification process should be completely transparent for all interruptible tariffs. When notification procedures are formalized the interruptible tariffs can provide greater clarity for the customer and expectations for the utility. A formal notification detailed in a tariff also gives the customer some redress if a utility fails to properly notify the customer of an event. Notification procedures in tariffs should also include specific expectations for customer response during economic versus emergency events, such as whether or not a customer can buy-through an event. Customers should be given the opportunity to express their preference for communication medium for notifications to ensure a timely response to events.

Testing procedures could also be included in the interruptible tariffs. By listing the testing procedures in the tariff, the risk to ratepayers is reduced because there would be assurance that the resource they ultimately pay for is available. This would also provide assurance for the utility, who is responsible for the load reduction at MISO. Further, including testing procedures in interruptible tariffs ensures that the standard to which the DR resource is tested will not change year-to-year. Real power testing versus simulation is still up for debate, because there is significant cost to the customer if actual load shedding must occur for testing purposes.

Modifying existing interruptible tariffs to conform with the recommendations provided in this report may take place in two types of proceedings before the Commission. First, changes to tariffs, including new interruptible program offerings, that affect the cost to serve customers typically occur in general rate cases by evaluating the costs and benefits of the program through the cost of service study and the impact on customer rates when viewed holistically with the other myriad changes and adjustments that occur in such cases. This venue also provides a formal and open forum for affected customers, Staff, and the utility to contest any proposed changes to interruptible tariffs. However, a general rate case proceeding can take up to 10 months and involves significant resources for normal quasi-judicial activities like discovery, expert testimony, and multiple hearings. A general rate case is most appropriate for numerous or significant alterations to interruptible tariffs.

Second, interruptible tariffs may also be updated through ex-parte cases before the Commission. In order for these cases to proceed, the proposed changes to the tariff cannot change the cost for any other customer. In this type of case "ex-parte" means "without party," which means that there are no other parties to the case besides the applicant and the Commission. The applicant, typically the utility, will file a revision to its tariff that is applicable to, its justification. The application may include an affidavit with supporting arguments. Staff experts review the ex-parte case application and submit its analysis to the Commission. The Commission can then approve, deny, or approve with modification. These proceedings are most appropriate for minor changes to tariff language, but can also be used to update tariffs for some of the recommendations made in this report. For example, the formalization of DR event notification would not cause the cost of service for any customer to increase, supposing the utility already has the infrastructure in place. Of course, a proceeding may begin as ex-parte, but the Commission or applicant may invite stakeholders to comment.

Recommendations

After hearing from various stakeholders and participants across four meetings, Staff has developed the following recommendations as directed by the Commission in U-20628. These recommendations were developed with significant input from Stakeholders and were initially outlined in the February 19th Solutions document.[34] Staff acknowledges that utilities, RTOs, and DR customers have already made improvements since PV19, and consequently offer several steps that build on this foundation. Per Commission direction in U-20628, Staff believes that the enhancements below will continue to improve LMR performance, enhance communication procedures, and augment reliability as DR expands throughout the state. Reasoning for these items are outlined below and found throughout the body of the report above.

I. Ensure LMR availability is properly accounted for in MISO's MCS tool

The primary contributor to Michigan's underperformance during PV19 was a failure to enter the proper availability into the MCS tool. In several cases, the utility marked DR customers as available in the MCS, when, in reality, those customers were not required to respond outside of the summer, via contract. Resource availability should be accurately represented in the MCS to avoid this issue in the future. Staff recognizes that MISO tariff revisions and changes to utility procedures since January 2019 have largely addressed this issue and advocate for full compliance with the relevant provisions of the MISO tariff. With ongoing MISO rules changes, including LMR accreditation, LSEs should also ensure that the information in the MECT is updated as changes are made.

II. Ensure clarity and consistency in communication processes

A lesser contributor to Michigan's underperformance during PV19 was to delayed or imprecise communication by the utility and confusion among the customers. DR notifications from the RTO should be processed in a timely manner and sent out to the customer as soon as possible,

[34] Solutions document here.

ideally within five minutes or less. Utility operators should recognize and train themselves on the various ways RTO notifications reach the operations center, in order to relay these instructions quickly and accurately to their account managers and customers In addition, the utility emergency notification to reduce load should sound and look different than an economic notification, to order to elicit the appropriate customer response. This communication could occur across a variety of platforms, such as automated message, telephone, and text in order to more easily and dependably reach customers. Additionally, multiple personnel contacts for each customer site should be on file to reduce the number of unreachable sites, and at a minimum be reviewed annually.

III. Increase DR provider interaction with the customer

Historically, emergency DR has rarely been called upon, but is expected to perform in full when dispatched. Currently, most Michigan utilities communicate with the customer at least once annually to review customer obligations, offer assistance, and develop load reduction plans as needed. More frequent interaction may be preferable as Michigan's DR portfolio expands and DR is called upon more often throughout the MISO region. Biannual or quarterly contact, particularly for non-direct load control customers, would help strengthen the DR provider-customer relationship, offer an opportunity to alleviate any concerns, and set expectations ahead of each season. More frequent contact could be assessed on a case-by-case basis, particularly for those customers who are participating in more than one program.

IV. Explore the use of enabling technologies where feasible and cost effective

Enabling technology, ranging from customer-owned devices to automated systems put in place by the utility, can help ease the customer's response obligation, provide visibility into DR deployment, and enable more sophisticated management of a provider's DR portfolio. Before such technologies can be widely adopted, the DR provider must have visibility into customer loads in real time, or as close to real time as is cost effective. With hourly AMI meter data available throughout most of the state, as well as real-time meters for some C&I customers, Michigan is well situated to make use of other technologies, should they prove to be cost effective in cases before the Commission. While real time metering for the majority of customers may be preferred, this is unlikely to be cost effective. Thus, DR providers should be directed to make full use of the existing infrastructure and make the case for new technology as it develops. Technologies such as automatic controls, automatic notification systems, and software platforms are key to some of the recommendations in this report and would continue to provide value as DR grows throughout the state. In particular, the utilization of a *centralized* software platform *like a demand response management system (DRMS) or a distributed energy resource management system (DERMS)* can assist with multiple aspects of DR registration, deployment, and reporting, stacking the value delivered by such a tool. With increased visibility into DR dispatch and real-time issues, such technologies could further enable DR value stacking by making it easier for the DR provider to manage customers enrolled in multiple programs, potentially increasing the value each MW could provide. In addition, any technologies adopted for DR purposes would likely prove useful in the future as DERs, including storage, expand in Michigan.

V. Direct utilities to explore DR partnerships for real-time metering, customer readiness, and a centralized platform

Per U-20348, utilities were encouraged to explore DR partnerships with DR aggregators and/or DR service providers to take advantage of expertise and existing capabilities. *Some utilities have done so.* As shown above, real-time metering, customer readiness and a robust software platform are key to building a successful and responsive DR portfolio. To the extent that utilities do not already possess these capabilities, partnering with a third-party *utility service* provider may be an efficient use of ratepayer dollars as compared to developing such assets in-house[35]. While utilities may have already developed some of these aspects above, partnerships could add valuable improvements to reliability and the utility-customer interface. This holds particularly true if the utility gains access to a centralized software platform, which would interact with each of the recommendations listed above. Ideally, a robust, user-friendly platform would help with customer registrations, streamline communications, enable real-time coaching, and quickly provide after-the-fact performance reports directly to the customer. A partnership could be leveraged by the utility to better manage its DR portfolio and more easily interact with the DR customer.

VI. Require an annual documented simulation, encourage real power testing where feasible

While real power testing may be the preferred method to ensure reliability under true emergency conditions, the MPSC Staff recognizes the impact such a test may have on the customer's operations. Rigorous simulations, documented for the benefit of the customer, utility, and RTO, may provide a reasonable substitute for a real power test. Simulations should reproduce emergency conditions, enable the customer to walk through each step of the emergency procedures, and provide an opportunity for after the fact learnings. If approached in this manner, simulations balance the reliability need of the system with the economic impact of a real power test. However, the severity of such economic impacts differs across customer classes and even individual customer sites. For example, heavy manufacturing and industrial processes incur a greater power interruption cost than a residential AC system. To the extent practicable, DR providers should be encouraged to perform a real power test where it is cost-effective to do so. This could include testing only a portion of the customer's accredited load

[35] *There are many factors that must be considered in evaluating the costs of in-house assets versus using partner assets – data security is a key element.*

reduction, which could provide valuable insight into the reliability of the resource while minimizing the impact to the customer. Utilities should be directed to *include a testing requirement* ~~list testing procedures~~ in their retail tariffs, which would enhance accountability for ratepayers, who will be assured that the resource they pay for is available, and for the utility, who is ultimately responsible for the load reduction at MISO.

VII. Formalize and standardize the notification procedure and penalties in utility tariffs

A formalized notification procedure will provide greater clarity for the customer and would set expectations before an event occurs. As discussed in Recommendation II, these procedures should include specific expectations for emergency versus economic events and give customers the opportunity to express their preference of notification method, whether that be via text, phone call, etc. A customer's preference should not preclude the utility from using multiple communication avenues during events. In addition, Staff recommends that the notification response window, how long the customer has until it must reduce load following a call from the utility, be made consistent across utilities. This way, an interruptible customer being served by different utilities at different locations would have the same expectations of interruption during an emergency event.

Staff also recommends that penalties should be made consistent between utilities, because non-interruption does not carry a different cost depending on service territory. Since the call for emergency interruption ultimately comes from MISO, the penalty should be the same for all customers in the same MISO zone. Likewise, penalties for non-interruption should remain consistent across rates within the same utility

VIII. Any necessary tariff changes should be made in a general rate case or an ex parte case

Changes to tariffs that affect the cost to serve customers should occur in general rate cases, where the costs and benefits of the program can be incorporated into the cost of service study and customer rates at the same time as the other myriad changes and adjustments that occur in such cases. However, since a rate case can take up to 10 months, a general rate case is most appropriate for numerous or significant alterations to interruptible tariffs. In instances where tariff changes do not change the cost for any other customer, Staff recommends that these changes occur in an ex-parte case. The ex-parte format lends itself well to minor changes and updates to tariffs, such as those linked to several of the recommendations in this report. The Commission remains free to invite stakeholders to comment on ex-parte proceedings.

IX. Enable DR value stacking

As the need for grid flexibility grows throughout the industry, DR's ability to provide multiple services will be increasingly valuable and should be encouraged wherever possible. Dual-registration options already exist at MISO and PJM, which should be matched by a diverse program offerings at the retail level. Staff recommends that testing of dual-registration options, particularly the economic or ancillary component of DR, occur through the pilot program process. To the extent that customer interest in dual-registration seems lacking, enhanced marketing strategies, increased customer education, and learning from outside Michigan should be used to augment utilities' efforts to engage its customer base. It is also through this process that the DR provider could test various M&V options, to match the utilities' needs while giving customers flexibility as to how their performance will be measured.

Conclusion

Throughout the four meetings Staff hosted, the utilities, RTOs and customers were provided with the opportunity to share experiences and lessons learned from PV19. The utilities presented on steps they have taken since January 2019 to improve future emergency DR events, and stakeholders discussed areas still in need of further analysis and/or improvement. The recommendations Staff makes above attempt to capture the invaluable feedback provided during this endeavor and improve the future of DR emergency events, as well as pave the path moving forward for additional DR program options to expand and refine Michigan's DR portfolio.

Interested stakeholders were presented with significant opportunity for participation through listserv messages, stakeholder meetings, and written feedback. Staff has reviewed and taken into consideration the proposed changes to the draft Staff report outline and has included as Appendix XX, finalized comments of those stakeholders who requested that they be attached to the final report.