ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Hunter Leland Sponsoring Witness: N/A Beginning Sequence No. LR876 Ending Sequence No. LR876

Question No.: TIEC 3-3 Part No.: Addendum:

Question:

Quantify the date, time, and duration of any curtailments required under Schedule IS that occurred during off-peak hours, as defined in the Company's Schedule LIPS-TOD, in the past ten years.

Response:

Off-peak hours are all hours of the year not defined as on-peak hours in the Large Industrial Power Service – Time of Day ("Schedule LIPS-TOD"). The Schedule LIPS – TOD nominates on-peak hours during the summer as the hours between 1:00 p.m. and 9:00 p.m. Monday through Friday beginning May 15th and continuing through October 15th of each year except for Memorial Day, Labor Day, and Independence Day. The Schedule LIPS – TOD defines on-peak hours during the winter as the hours between 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m. except Thanksgiving Day, Christmas Day, and New Year's Day or nearest weekday if the holiday falls on a weekend.

The table below lists the instances when a curtailment required under Schedule Interruptible Service ("IS") occurred during off-peak hours even in part.

Date	Time	Duration	Notes
April 17, 2017	05:00 p.m.	1 hours	Off-peak period was the beginning of a curtailment called to end at 9:00 p.m.
January 18, 2018	05:00 a.m.	1 hours	Off-peak period was the beginning of a curtailment called to end at 9:00 a.m.
February 15, 2021	05:00 p.m.	1 hours	Off-peak period was the beginning of a curtailment called to end at 9:00 p.m.
February 17, 2021	5:00 p.m.	1 hours	Off-peak period was the beginning of a curtailment called to end at 8:00 p.m.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Hunter Leland Sponsoring Witness: N/A Beginning Sequence No. LR878 Ending Sequence No. LR879

Question No.: TIEC 3-4 Part No.: Addendum:

Question:

Provide documentation for each instance listed in the response to TIEC 3-3 when a Schedule IS customer failed to curtail load down to the Firm Contract Power as specified in VI. B. of the otherwise applicable firm tariff.

Response:

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.110. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

Please see the highly sensitive attachment (TP-53719-00TIE003-X005_HSPM) for documentation of customers who failed to curtail down to the Firm Contract Power during an off-peak period. Highly sensitive materials have been included on the secure ShareFile site provided to the parties that have executed protective order certifications in this proceeding.

DESIGNATION OF PROTECTED MATERIALS PURSUANT TO PARAGRAPH 4 OF DOCKET NO. 53719 PROTECTIVE ORDER

The Response to this Request for Information includes Protected Materials within the meaning of the Protective Order in force in this Docket. Public Information Act exemptions applicable to this information include Tex. Gov't Code Sections 552.101 and/or 552.110. ETI asserts that this information is exempt from public disclosure under the Public Information Act and subject to treatment as Protected Materials because it concerns competitively sensitive commercial and/or financial information and/or information designated confidential by law.

Counsel for ETI has reviewed this information sufficiently to state in good faith that the information is exempt from public disclosure under the Public Information Act and merits the Protected Materials Designation.

Kristen F. Yates
Entergy Services, LLC.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Hunter Leland Sponsoring Witness: N/A Beginning Sequence No. LR880 Ending Sequence No. LR881

Question No.: TIEC 3-5 Part No.: Addendum:

Question:

Provide documentation for each instance listed in the response to TIEC 3-3 when the failure of a Schedule IS customer to curtail load down to the Firm Contract Power level during on-peak hours resulted in ETI incurring a financial penalty from MISO for non-compliance.

Response:

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.110. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

Please see the highly sensitive attachment (TP-53719-00TIE003-X005_HSPM) for penalties related to the January 18 curtailment. Highly sensitive materials have been included on the secure ShareFile site provided to the parties that have executed protective order certifications in this proceeding.

DESIGNATION OF PROTECTED MATERIALS PURSUANT TO PARAGRAPH 4 OF DOCKET NO. 53719 PROTECTIVE ORDER

The Response to this Request for Information includes Protected Materials within the meaning of the Protective Order in force in this Docket. Public Information Act exemptions applicable to this information include Tex. Gov't Code Sections 552.101 and/or 552.110. ETI asserts that this information is exempt from public disclosure under the Public Information Act and subject to treatment as Protected Materials because it concerns competitively sensitive commercial and/or financial information and/or information designated confidential by law.

Counsel for ETI has reviewed this information sufficiently to state in good faith that the information is exempt from public disclosure under the Public Information Act and merits the Protected Materials Designation.

Kristen F. Yates
Entergy Services, LLC.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Ryan Magee Sponsoring Witness: N/A Beginning Sequence No. LR900 Ending Sequence No. LR901

Question No.: TIEC 3-6 Part No.: Addendum:

Question:

Referring to the proposed SMS rate schedule:

a. Explain the reasons for the proposed new language in III. A. (1). In particular, why would Schedule GS be the default firm power rate schedule if the customer would otherwise qualify for different rate schedule based on the customer' s size and delivery voltage?

b. Explain the reasons for the proposal to increase the prior notification requirement for Maintenance Service from 24 hours to five days.

c. Explain the reasons for the proposal to limit the availability of Maintenance Service to not more than six times per calendar year or 90 calendar days per Contract Year, whichever is reached first.

d. Define the circumstances in III. B. when Maintenance Service would be no longer available to the Customer.

Response:

a. The proposed change is to prevent potential gaming of the Standby and Maintenance Service ("SMS"). Prior to the new language, large customers could contract for only 1MW of SMS thereby having the SMS rate available to them, but actually need 100 MW of SMS power in the event their co-generating units go off-line. The new proposed language encourages customers to sign-up for the amount of SMS they know they will need and pay monthly reservation fees associated with that need. The firm power rate schedules typically applicable to customers on SMS would be the General Service ("GS"), Large General Service ("LGS"), or Large Industrial Power Service ("LIPS") rate schedules. The minimum billing demand for these rate schedules is 5 kW, 300 kW, and 2500 kW, respectively. Entergy Texas, Inc. ("ETI") elected to have the default be the rate schedule with the least restrictive minimum billing demand. This default would apply until the customer executes a contract for service under the applicable rate schedule that meets the customer's needs. This change allows ETI to study the outage and provide timely customer feedback.

b. The proposed change to the prior notification requirement in Schedule SMS is consistent with a customer's planning for a co-generation unit outage because a customer will need to know the schedule for any planned work in advance and be required to schedule crews and material for the co-generation unit's maintenance outage.

c. The intention of the maintenance service under Schedule SMS was for limited planned co-generation maintenance. Prior to the proposed new language for Schedule SMS, an SMS customer could rely on maintenance service throughout the year instead of paying for firm service. A customer's cogeneration should be available for greater than 75% of the calendar year, otherwise the customer requires firm service.

d. For an illustration of when the Maintenance Service would no longer be available to the customer, please see below:

<u>Illustrative</u>

Customer 1:

- 1 schedule maintenance – lasts 45 days (schedule = 1: days = 45)
- 2 schedule maintenance – lasts 30 days (schedule = 2: days = 75)
- 3 schedule maintenance – lasts 20 days (schedule = 3: days = 95); 5 days of this schedule would be disapproved because the days exceed 90.

Customer 2:

- 1 schedule maintenance – lasts 5 days (schedule = 1: days = 5)
- 2 schedule maintenance – lasts 5 days (schedule = 2: days = 10)
- 3 schedule maintenance – lasts 20 days (schedule = 3: days = 30)
- 4 schedule maintenance – lasts 10 days (schedule = 4: days = 40)
- 5 schedule maintenance – lasts 7 days (schedule = 5: days = 47)
- 6 schedule maintenance – lasts 4 days (schedule = 6: days = 51)
- 7 schedule maintenance–lasts 3 days (schedule =7: days = 54); After the 6th scheduled maintenance of the calendar year, the 7th scheduled maintenance would be denied.

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Hunter Leland Sponsoring Witness: N/A Beginning Sequence No. LR902 Ending Sequence No. LR902

Question No.: TIEC 3-7   Part No.:   Addendum:

Question:

Does MISO limit maintenance outages of ETI generating resources to six outages per year or 90 calendar days, whichever is reached first? If so, please provide supporting documents.

Response:

No, Midcontinent Independent System Operator ("MISO") does not limit maintenance outages of generating resources to six outages per year or 90 calendar days. However, MISO has rules and limitations for generation outages included in the MISO Tariff and applicable Business Practice Manuals ("BPM"). For example, BPM-011 states that resources with pending full or partial outages that are planned and/or scheduled and reasonably expected to encompass ninety or more of the first 120 calendar days in the Planning Year shall be precluded and/or prohibited from participation in that Planning Year's Planning Resource Auction ("PRA").

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Andrew Owens Sponsoring Witness: David E. Hunt Beginning Sequence No. LR882 Ending Sequence No. LR882

Question No.: TIEC 3-8 Part No.: Addendum:

Question:

Regarding the proposed Market Valued Demand Response Rider (MVDR)

a. Are Aggregators of Retail Customers (ARCs) or similar organizations eligible to qualify as a Market Participant?

b. Does MISO allow ARCs or similar entities to participate as LMRs?

c. Does MISO allow ARCs or similar entities to participate in the (real-time and/or day-ahead) energy and capacity markets?

d. Do other MISO members allow ARCs or similar entities to act as Market Participants on behalf of the retail customers served by these other MISO members?

Response:

a. Yes, Aggregators of Retail Customers ("ARCs") are eligible to qualify as a Market Participant in Midcontinent Independent System Operator ("MISO") unless the laws or regulations of the Relevant Electric Retail Regulatory Authority ("RERRA") do not permit an ARC (or retail customer) to participate directly.

b. No, ARCs do not participate as Load Modifying Resources ("LMRs"). Instead, if not otherwise prohibited by the RERRA, ARCs are able to register and represent retail customer demand response ("DR") capabilities in wholesale markets such as MISO if the ARC is the Market Participant.

c. Yes, if not otherwise prohibited by the RERRA.

d. No. MISO members do not determine whether or not an ARC or similar entities are able to act as a Market Participant. See also the Company's response to TIEC 3-8(a).

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Andrew Owens Sponsoring Witness: David E. Hunt Beginning Sequence No. LR883 Ending Sequence No. LR883

Question No.: TIEC 3-9 Part No.: Addendum:

Question:

Has ETI or any other Entergy affiliate ever allowed ARCs or similar entities to act as Market Participants on behalf of participating retail customers? If so, list all such ARCs or similar entities representing retail customers that have qualified as a Market Participant.

Response:

Please see the Company's response to TIEC 3-8(d).

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Andrew Owens Sponsoring Witness: David E. Hunt Beginning Sequence No. PI1632 Ending Sequence No. PI1663

Question No.: TIEC 3-10 Part No.: Addendum:

Question:

Please provide a copy of any orders issued by the state regulatory commissions of Arkansas, Louisiana, or Mississippi that are known to ETI and address the issue of whether ARCs or similar entities should be allowed to act as a Market Participant on behalf of retail customers in the context of a tariff similar to ETI' s proposed Rider MVDR.

Response:

Please see the attachments (TP-53719-00TIE003-X010-001 through TP-53719-00TIE003-X010-005). With respect to Arkansas, the attached is not an order issued by the Regulatory commission but was enacted into law in 2013.

LOUISIANA PUBLIC SERVICE COMMISSION

GENERAL ORDER 3-7-2019 (R-34948)

LOUISIANA PUBLIC SERVICE COMMISSION
EX PARTE

Docket No. R-34948, In re: Rulemaking to study the implications of participation of Aggregators of Retail Customers to determine whether, and under what conditions, such activity should be allowed in the Louisiana Public Service Commission's jurisdiction

(Decided at the Commission's February 21, 2019 Business and Executive Session.)

I. INTRODUCTION

This proceeding was initiated pursuant to the Louisiana Public Service Commission's ("Commission" or "LPSC") June 20, 2018 Business & Executive Session ("B&E") directive to Staff to open a rulemaking docket to study the implications of the participation of Aggregators of Retail Customers ("ARCs") in the wholesale markets and to determine whether, and under what conditions, such activity should be allowed under the jurisdiction and authority of the Commission." The directive was prompted by information that at least one third-party ARC recently had engaged in soliciting one or more LPSC- jurisdictional retail electric customers to enter into agreements with the ARC, whereby the ARC could combine customers into a group for the purposes of participating in the wholesale markets of the Midcontinent Independent System Operator, Inc. ("MISO") as a demand resource. ARCs are in the business of entering into agreements with, and combining the abilities of, multiple retail customers in order to represent them in wholesale electric markets. In Order Nos. 719 and 719-A, the Federal Energy Regulatory Commission ("FERC") has recognized that it is up to the state regulators to determine whether third-party ARCs should be eligible to represent customers in wholesale markets and whether, and under what conditions, ARCs may do business under state law. These are issues of first impression for the Commission.

A. <u>Notice and Interventions</u>

Notice of this proceeding was published in the LPSC's Official Bulletin No. 1171, dated July 13, 2018. Interventions were due on or before August 7, 2018. Timely interventions were filed by Louisiana Energy Users Group ("LEUG"), Southwestern Electric Power Company ("SWEPCO"), Dixie Electric Membership Corporation ("DEMCO"), the Alliance for Affordable Energy ("AAE"), Association of Louisiana Electric Cooperatives ("ALEC"), Entergy Louisiana, LLC ("ELL"), Marathon Petroleum Co LP. ("Marathon"), Cleco Power, LLC ("CLECO"); Voltus, Inc. ("Voltus"); and the Lafayette Utilities System ("LUS"). On August 24, 2018, a motion for leave to intervene out of time was filed on behalf of the Advanced Energy Management Alliance ("AEMA").

B. Interim Directive

At the September 19, 2018 B&E, an additional directive was sponsored by Chairman Skrmetta, and approved by the Commission, ruling that third-party ARCs were not allowed to register LPSC-jurisdictional customers or participate in wholesale markets on their behalves pending the outcome of this rulemaking. That directive stated:

> At the June 20, 2018 B&E meeting, a Commission directive was adopted opening a rulemaking to determine whether and under what conditions third-party aggregators of retail customers or ARCs can participate in Louisiana in utility service areas subject to the Commission's jurisdiction. Commission Docket R-34948 was noticed pursuant to the directive. Subsequent to this directive and the rulemaking being opened, I understand that one or more utilities have received requests from MISO regarding requests by ARCs to register LPSC jurisdictional retail electric service customers to participate in MISO. While I think the prior directive was clear, in the event that there was any confusion regarding the current status of ARCs, this directive is to clarify that the registration of LPSC-jurisdictional retail electric service customers by third-party ARCs and/or the bidding of such retail customers' loads by third-party ARCs in RTO or ISO markets is not authorized unless and until it is approved as part of the pending rulemaking. The pending rulemaking will determine whether this activity will be permitted in Louisiana in the future and, if so, under what circumstances.

That decision remains in effect until a final rule is issued in this docket.

II. JURISDICTION AND AUTHORITY OF THE COMMISSION

The Louisiana Commission has plenary authority to regulate the services and operations of public utilities operating in Louisiana. Article IV, Section 21 (B) of the Louisiana Constitution of 1974 provides:

> (B) Powers and Duties. The commission shall regulate all common carriers and public utilities and have such other regulatory authority as provided by law. It shall adopt and enforce reasonable rules, regulations, and procedures necessary for the discharge of its duties, and shall have other powers and perform other duties as provided by law.

Additional authority is provided pursuant to La R.S. 45:1163 A(1) which states:

> A.(1) The commission shall exercise all necessary power and authority over any street railway, gas, electric light, heat, power, waterworks, or other local public utility for the purpose of fixing and regulating the rates charged or to be charged by and service furnished by such public utilities.

Additional authority also is provided pursuant to La. R.S. 45:1164 (A) which states:

> A. The power, authority, and duties of the commission shall affect and include all matters and things connected with, concerning, and growing out of the service to be given or rendered by such public utility, except in the parish of Orleans.

These provisions grant to the Commission broad, plenary, independent power and authority to regulate common carriers and public utilities. To accomplish this goal, the Commission may adopt and enforce reasonable rules, regulations, and procedures necessary for the discharge of its duties. *Louisiana Power & Light Co. v. Louisiana Public Service Comm.*, 609 So. 2d 797 (La. 1992).

III. BACKGROUND

A. FERC Order Nos. 719 and 719-A

FERC Order No. 719 required each Regional Transmission Organization ("RTO") to accept bids from demand response resources in RTO markets on a basis comparable to other resources and permitted, under certain circumstances, an ARC to bid demand response on behalf of retail customers directly into the organized energy markets. It required that RTOs amend their market rules in order to permit an ARC to bid demand response on behalf of retail customers directly into the RTO's organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate. *Order No. 719, Wholesale Competition in Regions with Organized Electric Markets*, 73 FR 61,400 (Oct. 28, 2008), FERC Stats. & Regs, ¶ 31,281 (2008). In Order 719-A, FERC, on rehearing, generally affirmed the findings of *Order 719*. It further stated that:

> The Final Rule's intent and effect are neither to encourage or require actions that would violate state laws or regulations nor to classify retail customers or their representatives as wholesale customers, as Ohio PUC asserts. The Final Rule also does not make findings about retail customers' eligibility, under state or local laws, to bid demand response into the organized markets, either independently or through an ARC. The Commission also does not intend to make findings as to whether ARCs may do business under state or local laws, or whether ARCs contracts with their retail customers are subject to state and local law. Nothing in the Final Rule authorizes a retail customer to violate existing state laws or regulations or contract rights. In that regard, we leave it to the appropriate state or local authorities to set and enforce their own requirements. Order No. 719-A, 129 FERC ¶61,059 (2009).

Clearly, FERC has recognized state authority over the interaction between ARCs and jurisdictional retail customers and their participation in the wholesale markets.

B. How ARCs May Participate in RTO Markets

In MISO, as a prerequisite of participation in its markets, the ARC must be registered as a Market Participant ("MP") and must have submitted timely the required registration documentation, including proof that the ARC is in compliance with state/local/regulatory rules, laws or requirements. An ARC can bundle multiple retail loads, but all such loads must be located within a single Local Balancing Authority ("LBA"). The ARC can register as a Demand Response Resource ("DRR") and offer into the energy and ancillary services markets. If the ARC also wants to qualify the DRR as a capacity resource, it can receive Zonal Resource Credits ("ZRC") commensurate with its ability to reduce load at the MISO peak - if the ARC accepts the MISO "must offer" requirements. Alternatively, the ARC could register the bundled resource as a Load Modifying Resource ("LMR"), receive ZRCs, and be obligated to respond to a MISO Emergency during the summer months, or under certain conditions at other times in the planning year. The ARC bundled resource may also register as an Emergency Demand Response resource ("EDR") in the MISO market if it meets the requirements for EDRs. In MISO, a Load Serving Entity ("LSE"), such as ELL or Cleco, which serve retail loads, may aggregate retail customers within their own service areas and participate with those aggregated customer DR in the MISO markets, but they are not considered ARCs under MISO rules. In compliance with FERC *Orders 719 and 719-A,* the Southwest Power Pool ("SPP") also adopted similar tariff language authorizing ARC participation in its markets.

C. Third-Party ARCs in Other MISO States

MISO's geographic service area includes all or part of fifteen states and the province of Manitoba in Canada. Only Illinois, a retail access state, specifically allows third party ARCs to interact with retail customers and to participate in MISO's wholesale markets. For example, the Arkansas legislature in 2013 passed Act 1078 to regulate demand response. Part of that Act provided:

> 23-18-1004. Marketing or selling of demand response prohibited.
> The marketing, selling, or marketing and selling of demand response into wholesale electricity markets by an aggregator of retail customers or by a retail customer is prohibited unless the Arkansas Public Service Commission or the governing authority of a municipally owned electric utility or a consolidated municipal utility improvement district determines that the marketing, selling, or marketing and selling of demand response into wholesale electricity markets by aggregators of retail customers or by retail customers is in the public interest.

This provision prohibits third-party ARCs unless and until the Arkansas Commission determines that they should be allowed. The Arkansas Commission is currently examining the issue in a docketed proceeding.

In 2010, the Indiana Utility Regulatory Commission completed an extensive examination of this subject that included evidence from all Indiana utilities and interested parties. *Cause No. 43566 Indiana Utility Regulatory Commission. (2010).* The IURC found that, "encouraging participation in the various demand response programs offered by RTOs in Indiana is in the public interest." Demand response mechanisms benefit retail customers by reducing or delaying the need for new costly generation. However, the IURC also found that direct retail customer participation in RTO demand response markets was not in the public interest. It stated:

> It is clear from the record that direct customer participation would introduce a significant degree of additional uncertainty into the evaluation of capacity needs and cost effectiveness in IRP filings with the Commission. Although it may be possible under some circumstances for utilities to anticipate how their load might be impacted by a customer's direct participation in RTO demand response, it is difficult for utilities to adequately fulfill their responsibilities under the Commission's IRP rules when the utilities lack sufficient information or input into such customer participation. It is challenging for utilities to project economic conditions years in advance in an effort to evaluate the cost effectiveness of various resource options for meeting their jurisdictional load obligations, and we do not find it appropriate to introduce greater uncertainty into this process without a demonstration of corresponding benefit. We find that excluding potential cost effective resource solutions from the IRP portfolio is counter to the coherent and comprehensive planning process required under Indiana law. (*Id.* at 45).

Not only was the IURC concerned about effects of direct participation on IRP planning, it was also concerned that unless cost effective demand response was pursued and administered through the incumbent utilities, the ability to lower costs by reducing the need for new purchase power and new generation due to demand response could be eroded or lost. In addition, the IURC was concerned that the direct participation thorough third-party ARCs "could shift costs to, and create risks for, the utility's remaining customers" because, "to the extent that a customer directly participates, that curtailable load can no longer be netted form the utility's forecast, so the utility will need to procure more resources than would otherwise be the case at the expense of all customers." (*Id.* at 46). The IURC ultimately determined that, "[b]ecause direct customer participation in RTO demand response has the ability to directly and significantly affect a utility's provision of electric service, we find that participation in RTO demand response should be done through the retail customers LSE. Through well-designed rate schedules or riders, we believe participating customers can obtain significant benefits from demand response, while preserving the utility planning process. (*Id.* at 47).

On March 29, 2016, the Michigan Public Service Commission re-affirmed its earlier 2010 decision prohibiting Michigan retail customers or aggregators of retail customers from participating in RTO wholesale power markets. It determined that the concerns supporting its earlier decision regarding aggregation of demand response resources for sale in the wholesale market remained unresolved. Those concerns included: "(1) operational issues for Michigan jurisdictional utilities, on both the real-time and long-term bases, especially with respect to capacity planning and procurement as well as emergency operations; (2) lack of Commission oversight of third-party aggregators; (3) the possibility that customers may enroll a demand resource in more than one demand resource program; and (4) cross-subsidization." *Order Closing Docket Case No. 16020 (3/29/2016).*

D. <u>LPSC Demand Response Requirements</u>

The Commission requires that its jurisdictional electric utilities plan their systems by optimizing the least cost set of resource options that satisfy the utility's load requirements over the planning period, and that process requires estimation and consideration of available demand-side resources. *LPSC, ex parte. In Re: Development and Implementation of Rule for Integrated Resource Planning for Electric Utilities, Corrected General Order*, Docket No. R-30021 (2012) ("IRP Order"). In the IRP Order, the electric utilities are required to evaluate all of their resource options, including their demand-side options and determine the amount of capacity required to serve their forecasted load taking into consideration those demand-side resources. Those demand-side resources include demand response potential, which are defined as,

> Load management programs that have the intended goal of reducing or shifting load from hours with high electricity costs and/or reliability problems. Demand Response programs may include direct load control (such as air conditioners or water heaters), or incentive rates designed to induce lower electricity use at times of high wholesale market process or when system reliability is jeopardized." (*IRP Order* at 3).

This IRP Order was developed and approved prior to RTO membership by Louisiana electric utilities.

In addition, the Commission has in recent years approved the investment in hundreds of millions of dollars of advanced metering equipment by electric utilities and allowed recovery of the costs for those investments from ratepayers. For example, Entergy Louisiana, LLC was authorized to commence the installation of advanced meters beginning in early 2019, and the estimated costs of that equipment is $ 315 million in electric plant. *In re: Application of Entergy Louisiana, LLC for Approval to Implement a Permanent Advanced Metering System and Request for Cost Recovery and Related Relief*, LPSC Order No. U-34320 (2017). A portion of the support for those investments included the potential for the implementation of demand response programs. The Order requires ELL to perform a study of potential demand response programs and potential incentives and file the report, conclusions, and recommendations within 12 months of the deployment of the Advanced Metering Systems. (*Id.* at 7).

Likewise, Cleco Power LLC received approval in 2011 to install $73.5 million in advanced metering equipment (offset by a $20 million DOE grant) and was allowed to recover the remaining costs through its annual FRP plans. It was also ordered to conduct a report on the potential implementation of demand response programs within 18 months of installation. Construction of Cleco's AMI system was completed in 2016. Cleco filed its demand response report in April 2015 and announced that it had selected some Time of Use Choice "TOUCH" rates for on-peak and off-peak hours.

IV. STAFF INITIAL REPORT AND RECOMMENDATION

On November 16, 2018, the Commission published and served in this docket the "Initial Staff Report and Recommendation" ("Initial Report") along with a "Notice of Initial Staff Report and Recommendation and Request for Comments" seeking comments on the Initial Report on or before Monday, December 10, 2018. In the Initial Report, Staff recommended that the Commission issue a general order and adopt rules prohibiting third-party ARCs from aggregating the loads of Commission-jurisdictional retail customers and participating in the RTO wholesale markets.

A. Summary of Initial Report

That Initial Report relied upon the Commission's recognition of the value that demand-side resources can create for all of its jurisdictional ratepayers through its IRP requirements and its approvals of investments in advanced metering equipment. The electric infrastructure is planned for the firm loads of all retail customers and paid for by all customers. The benefits of demand-side resource programs should be managed by the Commission in a manner that is fair, just and reasonable to those same jurisdictional customers. Direct participation through third-party ARCs as demand response in the RTO markets will interfere with and devalue the ability of the utility to rely on that demand response for retail planning purposes.

The IRP process requirements rely upon these demand resource assets as being fully available to benefit retail customers. The "Resource Needs Assessment, Identification of Viable Resource Alternatives, Demand-Side Resource Evaluation, Optimization Analysis, and Final Expansion Plan Selection Process," as part of the IRP process, depends upon an accurate evaluation of and reliance upon the needs of utility customers and their demand-side resource potential. Direct participation by retail customers as demand resources in wholesale markets through third-party ARCs potentially could interfere with the efficacy of the IRP Order and resulting utility IRP plans, which can be offered in support of future independent requests for certification.[1]

Further, allowing direct participation by retail customers as demand resources in wholesale markets through third-party ARCs could interfere with and devalue investments already funded by ratepayers in advanced metering equipment. For, example, the Commission approved the implementation of the advanced metering systems and the recovery of those costs, in part, in reliance upon the ability of that technology to support demand-side resource programs to benefit all retail ratepayers.

The Initial Report does not deny Louisiana ratepayers the opportunity to benefit from the RTO wholesale demand response programs. Louisiana electric utilities as LSE's members of those RTOs, as they are today, are allowed and encouraged by this rule to develop and implement demand response rate schedules and programs designed to reduce the demand for and the cost of electricity. LSE's are encouraged to work together with third party demand response agents who work with the utility to aggregate DR load, if such efforts are prudent and cost efficient, to encourage and implement the demand response programs and to take advantage of the demand response benefits offered by the RTO markets. However, those programs must be developed and implemented under the regulatory authority of the Commission; the Commission will determine the effectiveness of those programs, and how the benefits should be shared by retail customers.

The Proposed Rule would not forever foreclose the potential that third-party ARCs may be allowed to conduct business in LPSC-jurisdictional areas. The Staff recommended instead that any third-party aggregator that wants to access, combine, and or enroll Louisiana retail end use customers in RTO demand response markets may petition the Commission for the opportunity to do so. The third-party ARC must consent to the jurisdiction of the Commission to regulate its business practices and interaction with retail customers, as well as consent to reporting requirements to the Commission and to the utility or utilities whose customers are being impacted. It also must demonstrate, in a docketed proceeding, which requires proper notice and follows the requirements of the Rules of Practice and Procedure of the Commission, to the satisfaction of the Commission that its proposed practices are just and reasonable and in the best interests of ratepayers.

[1] The Commission does not approve a utilities' IRP, however that information is used in the Commission's consideration of resource certification and the utilities' planning processes.

B. Comments on the Initial Report

Timely comments on the Initial Report were filed on behalf of AAE, SWEPCO, ELL, Cleco, Voltus, AEMA, and the LEUG. Each set is addressed separately below.

1. SWEPCO

SWEPCO supports the recommendation for rules prohibiting third-party ARCs from aggregating the loads of jurisdictional retail customers and participating in wholesale markets. It states that the unregulated aggregation of jurisdictional retail customers by third party ARCs for participation in the wholesale market as a demand response resource is contrary to the established goals of the IRP Order and interferes with long-term resource planning by utilities. SWEPCO also urges that allowing customers to participate in a demand response program undermines the utility's ability to rely on those resources for retail resource planning. SWEPCO requests no changes to the Proposed Rule as set forth in the Initial Report.

2. CLECO

CLECO generally supports the Initial Report. However, it suggests changes to Section 2 of the Proposed Rule to make it clear that demand response programs and rate schedules offered by an Electric Public Utility should be limited to the retail customers of that utility. CLECO's recommended language changes are appropriate and consistent with the intent of the Proposed Rule. The intent of Section 2 was not to expand the customer base of regulated utilities. It was merely to make it clear that the Rule did not prohibit utilities from offering demand response programs by contracting with third parties for such purposes. Edits are included in the final Proposed Rule that should eliminate CLECO's concern.

3. ELL

ELL supports the Proposed Rule and the Initial Report. It emphasized the need for the rule because after the issuance of the Commission's June 2018 directive, ELL continued to receive from MISO inquiries related to Voltus' continuing attempts to register ELL customers for direct participation in MISO's wholesale markets, and Voltus' issuance of a press release announcing its 125 MW "virtual power plant in New Orleans", which is outside of the LPSC's jurisdiction. ELL also provided verification of the Initial Report's findings that no other MISO state, except Illinois, a retail access state, authorizes third-party ARCs to operate within their jurisdictions. ELL urges that customer participation in RTO markets through third-party ARCs creates uncertainty in resource planning, increases costs for all customers, and has adverse effects on transmission planning. ELL further requests that any proceeding brought by a third-party ARC to obtain authority to operate in Louisiana under the jurisdiction of the LPSC be a publicly noticed, docketed proceeding and that more thought be given to the types of requirements and consumer protections needed for a third-party ARC to operate.

It is the intent of Staff that any proceeding initiated by this rule to consider participation by third-party ARCs would follow the LPSC's Rules of Practice and Procedure and be a docketed proceeding with notice and intervention. That language is already part of Section 4 of the Rule, and additional language is not needed. It is also the intent of the Staff that rules should be developed to be in place should a third-party ARC seek to take advantage of Section 4 of the Proposed Rule. Language is included in Section 5 to recommend a separate rulemaking to address those issues after a rule is approved in this docket.

4. AAE

AAE misinterprets the language and intent of the Initial Report and Proposed Rule. AAE argues that while banning third-party ARCs from participating in the RTO markets is consistent with the actions of many MISO states, "banning ARCs from operating in Louisiana altogether would further delay Louisiana in DR exploration." It urges that utilities could partner with ARCs to manage demand response programs, resulting in maintaining LPSC jurisdiction and oversight, adding value to AMI investment and saving ratepayers thousands of dollars. Staff agrees, and that is precisely what this Proposed Rule adopts. Section 2 of the Proposed Rule specifically states that Electric Utilities shall continue to offer demand response programs, that they are authorized to work with agents to aggregate load for participation in RTO markets, and that the costs of such programs are eligible for recovery in rates. This is precisely what AAE seeks. Further, the Preamble to the Proposed Rule makes it a policy of the Commission to promote demand response programs and rate schedules and to promote participation of demand response in RTO markets in a manner that is regulated carefully by the Commission.

The Proposed Rule, however, does not directly require the development of demand response rate schedules and rules. That was beyond the scope of the proceeding and beyond the scope of the published notice of this proceeding. It does recommend a follow up rulemaking addressing these issues. In addition, the Commission has existing rules addressing demand response, including certification of such programs, as set forth in Commission's General Order dated September 22, 2009 ("AMS/DR Order").

5. AEMA

AEMA is a non-profit trade association whose members include demand response providers, national distributed energy resource companies, advanced energy management service and technology providers, and some of the nation's largest demand response and distributed energy resources. AEMA asserts that the Commission can fully retain its jurisdiction and authority and at the same time capture for customers the benefits that demand response resources are capable of providing. It distinguishes third-party demand response providers, which work with and through regulated utility partners and do not take retail customers and load directly to wholesale markets without the permission of retail regulators, from the ARCs that this Proposed Rule is addressing. It recommends that the Commission adopt rules that allow customers to participate in demand response programs through the incumbent utility electric service providers and/or through Commission approved demand response providers. AEMA also seeks an expedited process to develop demand response rules/rate schedules and programs that are robust and allow for collaborative stakeholder input. AEMA makes some wording recommendations to the proposed rules that would require an expedited process to maximize demand response resources and to better recognize the differences between third-party ARCs and third-party demand response providers.

The current version of the proposed rules already requires, if adopted, the opening of a new demand response rulemaking, which would be properly noticed and would allow for a collaborative process with interested stakeholders that wish to participate. Although the new rulemaking should not provide an open-ended process, the AEMA 90-day from start to completion request to develop comprehensive demand response programs/rate schedules is overly aggressive and may limit unnecessarily the ability of parties to fully express their views and to develop the most effective rate schedules and programs. The Staff recommends instead a process that could begin as quickly as possible given administrative and due process requirements. In addition, Section 2 of the proposed rule already recognizes the differences between third-party ARCs and other entities that work together with incumbent utilities to allow Louisiana Retail Customers to participate in retail demand response programs and wholesale demand response markets. Some additional language is added to clarify this provision.

6. LEUG

LEUG comments recognize the need for LPSC oversight and regulation of demand response programs and rate schedules. However, it expresses the urgent need for the Commission to initiate proceedings now to develop demand response rate schedules for industrial customers in coordination with utilities, and customers, subject to review and approval by the Commission, and it urges that the Commission not "have yet another rulemaking to decide whether utilities should offer these rate schedules in Louisiana." LEUG cites recent MaxGen[2] events as evidence of the importance of developing new interruptible, real-time pricing and other demand response products as quickly as possible to avoid some of the costs of replacement generating capacity, energy price spikes, and outages. It also points to the fact that ELL interruptible rate schedules have been closed to new business for approximately 20 years. LEUG states that large industrial customers should be allowed to participate in RTO demand response programs directly, through aggregators, or through their electric service providers at the customer's discretion.

The Proposed Rule recommends the opening of a new rulemaking to examine and develop retail demand response rate schedules and programs. That rulemaking will be on a timetable that allows for administrative and due process needs, but also the efficient development of demand response rate schedules and programs, while allowing full participation of and collaboration with interested parties. How customers, including industrial customers, are allowed to participate in the RTO Demand Response markets will be explored and determined in that rulemaking. Consistent with the preamble of the Proposed Rule, the results of that process should be to retain for retail ratepayers the benefits created by Demand Response mechanisms that act to delay or reduce the need for new generating capacity or purchased power agreements; and to allocate these benefits among all retail ratepayers in a fair, just and reasonable manner. Some changes to the wording of the Proposed Rule were made to reflect the LEUG concerns.

7. <u>Voltus</u>

Voltus complains that ARCs should be allowed to operate in Louisiana so that they could enroll large energy users directly to participate in RTO markets. It argues that the Staff made a recommendation without allowing a fair opportunity for stakeholders, including Voltus, to see and respond to the information provided by other parties. It accuses Staff of engaging in *ex parte* communications with Cleco and Entergy. It accuses the Commission of prioritizing new generation construction that "Entergy and Cleco can ratebase, like the $388.5 million in advanced metering costs" instead of prioritizing "least cost" resources that it claims ARCs, like Voltus, can

---

[2] The LEUG reference refers to MISO RTO procedures for dealing with Maximum Generation or "MaxGen" events, which are adopted consistent with NERC rules for dealing with reliability emergencies such as extreme weather events.

provide. Voltus does not dispute the Commission's authority to prohibit ARCs in its jurisdictional areas, nor does it deny that the majority of MISO states have and continue to prohibit ARCs from engaging in a business model similar to the Voltus model, which is based upon direct interaction with retail customers without oversight or approval.

Voltus was allowed the same opportunity to participate in this rulemaking as all other interested entities. Informal communication with Staff is not prohibited in rulemakings. In fact, Mr. Dixon contacted Staff and informally provided information supporting his and Voltus' views on the rulemaking on more than one occasion, including a conference call held on September 28, 2018 that was set up at his request. The Proposed Rule provides a potential pathway for Third-Party ARCs, like Voltus, to engage in business in the portions of Louisiana subject to the jurisdiction of the LPSC. Section 4 of the Proposed Rule allows Voltus to petition the Commission for authority to engage in business, if it can demonstrate that such activity is in the public interest and if it consents to the jurisdiction of the Commission to regulate its business practices and its interaction with retail customers, as well as consent to reporting requirements to the Commission and to the utility or utilities whose customers are being impacted.

V. FINAL STAFF REPORT AND RECOMMENDATION

After consideration of the comments received and discussed above, Staff filed its "Final Staff Report and Recommendation" with an accompanying "Notice of Final Staff Report and Recommendation" on February 6, 2019. Staff advised that it planned to place the matter on the Commission's February 21, 2019 B&E Agenda for consideration and recommending that the Commission adopt the Proposed Rule as follows:

<u>Preamble:</u> It shall be the policy of the Louisiana Public Service Commission 1). to promote retail demand response programs and rate schedules and to promote participation of demand response in RTO wholesale markets and programs in a manner that preserves the Commission's jurisdiction, authority, and ability to regulate and monitor those efforts; 2). to promote full compliance with the requirements and intent behind its IRP Order and planning requirements; 3). to retain the value of the investment by retail ratepayers in advanced metering system equipment and technologies; 4). to reasonably maximize access to the cost-effective demand-side resources within the LPSC's jurisdiction; 5). to retain for retail ratepayers the benefits created by Demand Response mechanisms that act to delay, or reduce the need for, new generating capacity or purchased power agreements; and 6) to allocate these benefits among retail ratepayers in a fair, just and reasonable manner.

Definitions:

Third-Party Aggregator(s) of Retail Customers: A person or entity that acts as an RTO market participant and that represents Demand Response on behalf of one or more eligible retail customers, for which the participant is not such customers' load serving entity, and intends to offer Demand Response directly into RTO markets.

Demand Response: Load management programs that have the intended goal of reasonably and cost-effectively reducing or shifting load from hours with high electric costs and/or reliability problems and reducing capacity needs. Demand Response programs may include, but are not limited to, direct load control (e.g., such as air conditioners and water heaters) or incentive rates designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Electric Public Utility(ies): Any entity defined as an "electric public utility" pursuant to La. R.S. 45:121 and that are subject to the regulatory jurisdiction of the Louisiana Public Service Commission.

Louisiana Retail Customer(s): Any person or entity taking electric service under a tariff of an Electric Public Utility.

Section 1. Third-Party Aggregators of Retail Customers shall be prohibited from soliciting, enrolling, or otherwise entering into agreements to participate in RTO Demand Response programs, rate schedules, or markets directly with Louisiana Retail Customers, unless such Third-Party Aggregator of Retail Customers has received Commission approval as provided for in Section 4 below.

Section 2. Electric Public Utilities may continue to offer retail Demand Response programs and rate schedules to their own customers located in their own service territories subject to applicable Commission rules and approval. Electric Public Utilities shall continue to be authorized to participate in RTO Demand Response programs, rate schedules, or markets on their own behalf or on behalf of one or more of their own Louisiana Retail Customers. Nothing in this rule is intended to prohibit or limit Electric Public Utilities from contracting with third-party agents, including third-party demand response providers, to solicit Louisiana Retail Customers and/or to provide products and services needed for their own Louisiana Retail Customers to participate in retail Demand Response programs and rate schedules or to participate in RTO Demand Response programs, rate schedules, or markets either individually or in groups, in accordance with applicable rate schedules and programs and subject to LPSC authority. Prudently-incurred expenses associated with contracts with and/or costs of third-party agents shall be eligible for recovery in rates under the ordinary ratemaking processes and procedures.

Section 3. The Commission shall open a rulemaking proceeding within 30 days after a final rule is issued in this docket to: 1). determine the need for rate schedules and programs offering Demand Response products; 2). develop comprehensive sets of rate schedules and programs offering retail Demand Response products and allowing for the participation of their own Louisiana Retail Customers in the Demand Response programs, rate schedules, or markets of the RTOs in which they are a member; 3). Determine whether certain larger customers should be allowed to participate directly in wholesale demand response programs and under what conditions; and 4). determine how the costs and benefits of any such rate schedules and programs shall be allocated and recovered. The Commission will determine in any final rule whether these rate schedules and programs shall be mandatory or voluntary, and it shall have approval authority over any rate schedules and programs that are developed. The Staff shall use its reasonable best efforts to conclude the rulemaking and bring a proposed rule for consideration to the Commission within 12 months of the intervention deadline of the rulemaking proceeding. Any existing approved demand response rate schedules and programs may remain in effect during the pendency of this rulemaking proceeding, and any existing authority to adopt voluntary demand response rate schedules and programs (e.g., those authorized by the AMI/DR Order) shall not be affected.

Section 4. Third-Party Aggregators of Retail Customers may be allowed to conduct business in LPSC-jurisdictional areas. A Third-Party Aggregator of Retail Customers that wants to access, combine, and/or enroll Louisiana Retail Customers in RTO demand response markets may petition the Commission for the opportunity to do so. As part of that petition, the Third-Party Aggregator of Retail Customers must consent to the jurisdiction of the Commission to regulate its business practices and its interaction with retail customers, as well as consent to reporting requirements to the Commission and to the utility or utilities whose customers are being impacted. It also must demonstrate, in a docketed proceeding that requires proper notice and follows the requirements of the Rules of Practice and Procedure of the Commission, to the satisfaction of the

Commission that its proposed practices are just and reasonable and in the best interests of ratepayers.

Section 5. The Commission will notice in its Official Bulletin, subject to intervention, a rulemaking proceeding for the purpose of developing rules under which Third-Party Aggregators of Retail Customers seeking authority to operate under Section 4 of this Rule will be allowed to do business within the LPSC's jurisdiction, including the interaction with Louisiana Retail Customers, Electric Public Utilities, and the Commission.

VI. COMMISSION ACTION

The Commission considered this matter at its February 21, 2019 Business and Executive Session. Chairman Francis made the following motion:

> I move to approve the Final Staff Report and Recommendation with the following changes: 1) Regarding the timeline estimate to complete the new rulemaking on demand response rate schedules and products, I move that the timeline be changed to reasonable best efforts to complete the rulemaking by September 2019 with a progress report at the Commission meeting in May; and 2) Regarding the Commission consultants in this matter, I move that the Commission's consultants and counsel from the current docket carry over to the new rulemakings, and they submit revised budgets for the additional work. The new rulemakings arise out of and are interrelated with the existing docket, and continuation of the consultants and counsel is in the public interest to avoid duplication and delay.

After discussion, Chairman Francis' motion was seconded by Commissioner Skrmetta and unanimously adopted. Therefore, Staff's Final Report and Recommendation filed February 6, 2019 is approved, subject to the modifications as set forth in Chairman Francis' motion, and the following rules are adopted and ordered:

Preamble: It shall be the policy of the Louisiana Public Service Commission 1). to promote retail demand response programs and rate schedules and to promote participation of demand response in RTO wholesale markets and programs in a manner that preserves the Commission's jurisdiction, authority, and ability to regulate and monitor those efforts; 2). to promote full compliance with the requirements and intent behind its IRP Order and planning requirements; 3). to retain the value of the investment by retail ratepayers in advanced metering system equipment and technologies; 4). to reasonably maximize access to the cost-effective demand-side resources within the LPSC's jurisdiction; 5). to retain for retail ratepayers the benefits created by Demand Response mechanisms that act to delay, or reduce the need for, new generating capacity or purchased power agreements; and 6) to allocate these benefits among retail ratepayers in a fair, just and reasonable manner.

Definitions:

Third-Party Aggregator(s) of Retail Customers: A person or entity that acts as an RTO market participant and that represents Demand Response on behalf of one or more eligible retail customers, for which the participant is not such customers' load serving entity, and intends to offer Demand Response directly into RTO markets.

Demand Response: Load management programs that have the intended goal of reasonably and cost-effectively reducing or shifting load from hours with high electric costs and/or reliability problems and reducing capacity needs. Demand Response programs may include, but are not limited to, direct load control (e.g., such as air conditioners and water heaters) or incentive rates designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Electric Public Utility(ies): Any entity defined as an "electric public utility" pursuant to La. R.S. 45:121 and that are subject to the regulatory jurisdiction of the Louisiana Public Service Commission.

Louisiana Retail Customer(s): Any person or entity taking electric service under a tariff of an Electric Public Utility.

Section 1. Third-Party Aggregators of Retail Customers shall be prohibited from soliciting, enrolling, or otherwise entering into agreements to participate in RTO Demand Response programs, rate schedules, or markets directly with Louisiana Retail Customers, unless such Third-Party Aggregator of Retail Customers has received Commission approval as provided for in Section 4 below.

Section 2. Electric Public Utilities may continue to offer retail Demand Response programs and rate schedules to their own customers located in their own service territories subject to applicable Commission rules and approval. Electric Public Utilities shall continue to be authorized to participate in RTO Demand Response programs, rate schedules, or markets on their own behalf or on behalf of one or more of their own Louisiana Retail Customers. Nothing in this rule is intended to prohibit or limit Electric Public Utilities from contracting with third-party agents, including third-party demand response providers, to solicit Louisiana Retail Customers and/or to provide products and services needed for their own Louisiana Retail Customers to participate in retail Demand Response programs and rate schedules or to participate in RTO Demand Response programs, rate schedules, or markets either individually or in groups, in accordance with applicable rate schedules and programs and subject to LPSC authority. Prudently-incurred expenses associated with contracts with and/or costs of third-party agents shall be eligible for recovery in rates under the ordinary ratemaking processes and procedures.

Section 3. The Commission shall open a rulemaking proceeding within 30 days after a final rule is issued in this docket to: 1). determine the need for rate schedules and programs offering Demand Response products; 2). develop comprehensive sets of rate schedules and programs offering retail Demand Response products and allowing for the participation of their own Louisiana Retail Customers in the Demand Response programs, rate schedules, or markets of the RTOs in which they are a member; 3). Determine whether certain larger customers should be allowed to participate directly in wholesale demand response programs and under what conditions; and 4). determine how the costs and benefits of any such rate schedules and programs shall be allocated and recovered. The Commission will determine in any final rule whether these rate schedules and programs shall be mandatory or voluntary, and it shall have approval authority over any rate schedules and programs that are developed. The Staff shall use its reasonable best efforts to conclude the rulemaking and bring a proposed rule for consideration to the Commission at Commission's September 2019 Business and Executive Session and shall provide a progress report on the rulemaking at the Commission's May 2019 Business and Executive Session. Any existing approved demand response rate schedules and programs may remain in effect during the pendency of this rulemaking proceeding, and any existing authority to adopt voluntary demand response rate schedules and programs (e.g., those authorized by the AMI/DR Order) shall not be affected.

Section 4. Third-Party Aggregators of Retail Customers may be allowed to conduct business in LPSC-jurisdictional areas. A Third-Party Aggregator of Retail Customers that wants to access, combine, and/or enroll Louisiana Retail Customers in RTO demand response markets may petition the Commission for the opportunity to do so. As part of that petition, the Third-Party Aggregator of Retail Customers must consent to the jurisdiction of the Commission to regulate its business practices and its interaction with retail customers, as well as consent to reporting requirements to the Commission and to the utility or utilities whose customers are being impacted. It also must demonstrate, in a docketed proceeding that requires proper notice and follows the requirements of the Rules of Practice and Procedure of the Commission, to the satisfaction of the Commission that its proposed practices are just and reasonable and in the best interests of ratepayers.

Section 5. The Commission will notice in its Official Bulletin, subject to intervention, a rulemaking proceeding for the purpose of developing rules under which Third-Party Aggregators of Retail Customers seeking authority to operate under Section 4 of this Rule will be allowed to do business within the LPSC's jurisdiction, including the interaction with Louisiana Retail Customers, Electric Public Utilities, and the Commission.

THIS ORDER IS EFFECTIVE IMMEDIATELY.

BY ORDER OF THE COMMISSION
BATON ROUGE, LOUISIANA
March 7, 2019

/S/ MIKE FRANCIS
DISTRICT IV
CHAIRMAN MIKE FRANCIS

/S/ FOSTER L. CAMPBELL
DISTRICT V
VICE CHAIRMAN FOSTER L. CAMPBELL

/S/ LAMBERT C. BOISSIERE, III
DISTRICT III
COMMISSIONER LAMBERT C. BOSSIERE, III

BRANDON M. FREY
SECRETARY

/S/ ERIC F. SKRMETTA
DISTRICT I
CHAIRMAN ERIC F. SKRMETTA

/S/ CRAIG GREENE
DISTRICT II
COMMISSIONER CRAIG GREENE

Stricken language would be deleted from and underlined language would be added to present law.
Act 1078 of the Regular Session

State of Arkansas *As Engrossed: S4/3/13*
89th General Assembly
Regular Session, 2013

A Bill

SENATE BILL 795

By: Senator Rapert
By: Representative Wren

For An Act To Be Entitled

AN ACT TO REGULATE ELECTRIC DEMAND RESPONSE; AND FOR OTHER PURPOSES.

Subtitle

TO REGULATE ELECTRIC DEMAND RESPONSE.

BE IT ENACTED BY THE GENERAL ASSEMBLY OF THE STATE OF ARKANSAS:

SECTION 1. Arkansas Code Title 23, Chapter 18, is amended to add an additional subchapter to read as follows:

Subchapter 10 — Regulation of Electric Demand Response Act

23-18-1001. Title.

This subchapter shall be known and may be cited as the "Regulation of Electric Demand Response Act".

23-18-1002. Definitions.

As used in this subchapter:

(1)(A) “Aggregator of retail customers” means a person that aggregates demand response from *retail* customers for the purpose of marketing, selling, or marketing and selling the aggregated demand response:

(i) To an electric public utility; or

(ii) Into a wholesale electricity market.

(B) "Aggregator of retail customers” does not include:

(i) An electric public utility to the extent that it engages in demand response programs or demand response aggregation activities with the *retail* customers in its own service territory as certificated by *the Arkansas Public Service Commission; or*

(ii) A municipally owned electric utility or consolidated municipal utility improvement district to the extent that it engages in demand response programs or demand response aggregation

activities *with the retail customers in its own service territory; and*

(2)(A) “Demand response” means a reduction in the consumption of on-peak or off-peak electric energy by *a retail* customer served by an electric public utility or a municipally owned electric utility or consolidated municipal utility improvement district relative to the *retail* customer's expected consumption in response to:

(i) Changes in the price of electric energy to the *retail* customer over time; or

(ii) Incentive payments designed to induce lower consumption of electric energy.

(B) “Demand response” includes demand response resources *capable of providing demand response.*

23-18-1003. Authority to regulate demand response.

(a) The marketing, selling, or marketing and selling of demand response within the State of Arkansas by electric public utilities or aggregators of retail customers to retail customers or by electric public utilities, aggregators of retail customers, or retail customers into wholesale electricity markets is subject to regulation by:

(1) The Arkansas Public Service Commission under Acts 1935, No. 324, as amended; or

(2) The local governing authority in the case of a municipally owned electric utility or a consolidated municipal utility improvement *district.*

(b) The commission:

(1) May establish the terms and conditions for the marketing, selling, or marketing and selling of demand response by electric public utilities or aggregators of retail customers to retail customers or by electric public utilities, aggregators of retail customers, or retail customers into wholesale electricity markets; and

(2) Shall not regulate demand response investments or demand response actions of a retail customer on the customer's side of the electric meter.

23-18-1004. Marketing or selling of demand response prohibited.

The marketing, selling, or marketing and selling of demand response into wholesale electricity markets by an aggregator of retail customers or by *a retail customer is prohibited unless the Arkansas Public Service Commission or the governing authority of a municipally owned electric utility or a consolidated municipal utility improvement district determines that the marketing, selling, or marketing and selling of demand response into wholesale electricity markets by aggregators of retail customers or by retail customers is in the public interest.*

23-18-1005. Applicability.

This subchapter does not prevent a nonresidential customer from opting out in accordance with § 23-3-405 of energy conservation programs and measures as defined in § 23-3-403.

/s/Rapert

APPROVED: 04/11/2013

Entergy

Entergy Services, LLC
Legal Department
639 Loyola Avenue
P.O. Box 61000
New Orleans, LA 70161
Tel 504 576 2984
Fax 504 576 5579
hbarton@entergy.com

Harry M. Barton
Assistant General Counsel
Regulatory

October 14, 2020

VIA OVERNIGHT DELIVERY
Brandon Frey, Secretary
Louisiana Public Service Commission
Galvez Building, 12th Floor
602 North 5th Street
Baton Rouge, LA 70802

Ms. Terri Lemoine Bordelon
Records Division
Louisiana Public Service Commission
P. O. Box 91154
Baton Rouge, Louisiana 70821-9154

Re: Rate Riders submitted in Response to LPSC Order No. U-35443

Dear Mr. Frey and Ms. Bordelon:

On behalf of Entergy Louisiana, LLC ("ELL" or the "Company"), I have enclosed the original and three hard copies of the following Riders and supporting documents:

1. New Rider MVDR, tariff pages 173.1-173.5, clean version;
2. Revised Rider FRP, Attachment A, tariff page 163.18, redlined version; and
3. Revised Rider FRP, Attachment A, tariff page 163.18, clean version.

Items 1-3 have been submitted to comply with LPSC Order No. U-35443, issued on September 28, 2020. The new Market Valued Demand Response Rider Schedule ("Rider MVDR") is consistent with Exhibit A to the Uncontested Stipulated Settlement filed on August 21, 2020 in LPSC Docket No. U-35443 and approved in Ordering Paragraph 1 of the aforementioned Commission Order. The minor revision to Attachment A to Formula Rate Plan Rider Schedule FRP-1 ("Rider FRP") complies with Paragraph 4 of the Uncontested Stipulated Settlement as new Rider MVDR is now an additional excluded schedule under Rider FRP. The new Rider MVDR and revised Rider FRP Attachment A will be effective as of September 28, 2020.

In accordance with Section 501.C of LPSC General Order 7/1/ 2019, I request that Staff issue a letter accepting these filings in response to and in compliance with Order No. U-35443. Such acceptance shall in no way prejudice the authority of the Commission to investigate or otherwise require changes to these submissions.

I also request that this correspondence be submitted into the record of LPSC Docket No. U-35443.

If you have any questions, please do not hesitate to call me. Thank you for your courtesy and assistance with this matter.

Respectfully submitted,

Harry M. Barton

HMB/ddm
Enclosures
cc (via e-mail): Commissioners
Kathryn Bowman
Lauren Temento
Official Service List for LPSC Docket No. U-35443

MARKET VALUED DEMAND RESPONSE RIDER SCHEDULE

I. AVAILABILITY

Rider Schedule MVDR is an optional service that provides either a qualifying Customer with firm load(s) or an "ARC" (either or both of which may be sometimes referred to herein as "Participant") an opportunity to participate as one or more "DR" resources in "MISO" wholesale markets. Participant must execute an MVDR Agreement to facilitate curtailment of a specified amount of firm electric load for a single qualifying meter (or multiple meters) through the Company acting as the "MP." Customers or ARCs shall not participate as a DR resource in "MISO" wholesale markets except through this Schedule MVDR or other Company-implemented DR effort. Rider Schedule MVDR is not available to any Participant with respect to non-firm load already under contract with the Company as interruptible or curtailable service, or otherwise participating in any other Company demand response effort, unless that Participant agrees to move such load to service under this Rider Schedule MVDR. A Participant that has executed an MVDR Agreement is prohibited from taking any temporary, standby, back-up, and/or maintenance service for such load during any DR event that occurs per Rider Schedule MVDR. Customers with "BTMG" at a specific Customer location using net metering or a related tariff as a "QF" are not eligible to take service under Schedule MVDR.

II. DEFINITIONS

ARC: Aggregator of Retail Customers.

BPMs: MISO Business Practice Manuals currently in effect.

BTMG: Behind-the-Meter Generation.

Curtailment Amount: The amount of firm load that the Participant reduces relative to the Consumption Baseline.

Customer: A person, firm, individual, partnership, association, corporation, or any governmental agency taking retail electric service from Entergy Louisiana, LLC.

DR: Demand Response.

DRR: Demand Response Resource.

DR Event: A MISO-initiated event requiring the reduction of demand by a Participant providing one or more DR products in MISO's markets.

Demand Response Offer: A standing offer by Customer or ARC to the Company to provide a DRR Type 1, DRR Type 2, EDR, LMR-DR, or LMR-BTMG resource in the MISO markets. This offer will be submitted to MISO by the Company in the MISO Day Ahead Market, Real Time Market, LMR offer process, or EDR offer process as applicable to the Participant's DR product type.

MARKET VALUED DEMAND RESPONSE RIDER SCHEDULE

EDR: Emergency Demand Response.

Firm MVDR Demand: The amount of firm load that the Participant agrees not to exceed during a DR event that occurs per Rider Schedule MVDR.

LMR: Load Modifying Resource.

MISO: Midcontinent Independent System Operator, Inc.

MISO FERC Tariff: MISO's current FERC-approved tariff and associated schedules.

MP: Market Participant. The Company shall be the sole MP in MISO for any and all DR resources provided by Participant within the Company's service territory.

QF: Qualifying Facility as per the Public Utility Regulatory Policies Act of 1978 as may be amended from time to time.

* Unless otherwise defined in § II above or elsewhere in this document, capitalized terms used throughout this document are as defined in the Midcontinent Independent System Operator (MISO) Business Practice Manuals (BPMs) or MISO FERC Tariff. To the extent that there is a conflict among defined terms reflected in these documents, the terms of this Rider shall be controlling.

III. GENERAL PROVISIONS

A. DESCRIPTION

Participation in Rider Schedule MVDR is voluntary and offers a Participant the opportunity to authorize the Company acting as a MP to register Participant's Curtailment Amount as one or more MISO wholesale DR products (DRR, EDR, and/or LMR) as specified in the executed MVDR Agreement in order to participate in the MISO day-ahead energy and operating reserve, real-time energy and operating reserve, and/or capacity market, as applicable. Participant will be compensated as per Rider Schedule MVDR with Participant's portion of any net MISO revenue resulting from participation as one or more MISO wholesale DR products. The Company shall be the sole MP in MISO for any and all DR resources provided by Participant within the Company's service territory.

Participation shall not begin until an MVDR Agreement has been executed and all applicable MISO registration requirements have been completed and certified by MISO. Participant must assist and coordinate with Company to comply with all applicable MISO requirements. DR resource designations available to a Customer or to an ARC acting on behalf of one or more Customers include DRR Type 1 and Type 2, EDR, LMR-DR, and/or LMR-BTMG. The MVDR Agreement will specify which DR type(s) and combinations thereof, if applicable, Participant has agreed to provide.

MARKET VALUED DEMAND RESPONSE RIDER SCHEDULE

B. CURTAILMENT

1. For DRR Type 1 and DRR Type 2 resources, Participant must provide the Company a minimum load reduction of the greater of (a) 1,000 kilowatts ("kW"), which can be aggregated from multiple Customer locations in accordance with the currently-effective MISO FERC Tariff and/or as described in the MISO BPMs or (b) the minimum specified in the currently-effective MISO FERC Tariff and/or as described in the MISO BPMs.

2. For EDR, LMR-DR, and LMR-BTMG resources, Participant must provide the Company a minimum load reduction of the greater of (a) 100 kW or (b) the minimum specified in the currently-effective MISO FERC Tariff and/or described in the MISO BPMs.

3. Participant must specify the firm electric load reduction as a Curtailment Amount below the Consumption Baseline or may limit demand to a Firm MVDR Demand. The method to compute the amount of load reduction for a DR Event is specified in the MVDR Agreement.

4. Each Customer location shall provide a minimum load reduction of 100 kW.

C. METERING AND COMMUNICATION

Customer or each retail Customer(s) aggregated by an ARC must have an interval data recording ("IDR") meter at least capable of participating in Rider Schedule MVDR. If the Customer location does not have the appropriate equipment already installed, such equipment will be installed by the Company at Participant's expense. All metering and communication equipment installed to enable Participant to take service under Rider Schedule MVDR is and will remain the property of Company.

D. DAILY PROCESS

As contemplated in the MVDR Agreement, participation by a Customer or ARC will be permitted on any day as per applicable MISO requirements. Participant's daily offer will be submitted to the Company to be included in the Company's daily offer to MISO. At the time of initial registration, the Participant will establish a default Demand Response Offer that will remain valid, including within the real-time market, unless the Participant modifies any parameter of the resource offer by the deadline as established in the MVDR Agreement. Participant shall provide accurate availability information, including timely update to Company for when any planned outage or similar event is scheduled.

E. REGISTRATION AND CAPACITY MARKET PROCESS

Participant must submit all information, including but not limited to real power testing, required by MISO for market registration and, if applicable, capacity market participation at least 30 days before the relevant MISO submission deadlines. However, for DRR resources, Participant must submit all information no later than 60 days prior to the applicable MISO deadline for the quarterly commercial model update in which Participant wants to register as a DRR Resource.

F. MISO PERFORMANCE REQUIREMENTS

Participant must comply with all MISO requirements as stated in MISO's currently-effective FERC tariff and as described in the MISO BPMs, including, but not limited to, the Demand Response BPM and the Resource Adequacy BPM.

G. AGGREGATION OF RETAIL CUSTOMER LOAD

An ARC aggregating one or more Customer DR resources shall be subject to all requirements set forth in Rider Schedule MVDR. In addition, the ARC must identify in the MVDR Agreement each Customer location being aggregated and provide all necessary information required by MISO for participation and certification as the DR type(s) selected. No Customer location(s) shall be represented by more than one ARC taking service under Rider Schedule MVDR. No Customer location(s) may participate directly via Rider Schedule MVDR and simultaneously through an ARC.

IV. MONTHLY BILLING

The Net Monthly Bill will be determined in accordance with the terms and calculations defined below and as per the MVDR Agreement.

A. MONTHLY SETTLEMENTS

1. For all DR resources, Company has the option to include on Customer's monthly electric bill or send a separate statement for the Customer's applicable MISO settlement amount (less 5%); and any penalty for failure to perform as outlined in Paragraph B. For any Customer location(s) participating via an ARC, Company will provide ARC with a monthly statement with applicable MISO settlement amount (less 5%); and any penalty for failure to perform as outlined in Paragraph B. In instances of liability to Customer for any harm arising from the Customer's relationship with the ARC, including but not limited to breach of contract, any applicable fees/penalties will fall upon the ARC itself.

2. Any MISO revenues related to Customer location(s) participation as a MISO DR product including participation via an ARC will be netted first against any applicable fees and/or penalties assigned by MISO that are specific to that participation; but, in no event shall the Company's allocated share be reduced below zero. Credit to Participant for each month, if any, owed for participation as a MISO DR product shall be remitted within 30 days after the end of the month to allow time for settlement and/or any true-ups as may be necessary to reflect any changes in current or prior MISO settlements. Such credits will be subject to adjustments, if any, from changes to MISO settlements in accordance with the "MISO FERC Tariff" and BPMs. Company and Participant shall agree upon the monthly compensation method per the MVDR Agreement.

B. PENALTY FOR FAILURE TO PERFORM

Participant shall be responsible for any and all net charges, fees, and/or penalties imposed on the Company by MISO relating to participation in the MISO markets, except for those arising from the Company's gross negligence or failure to perform as directed by MISO. All fees and/or penalties imposed on the Company by MISO for a particular Participant will be netted against any MISO revenues payable to that Participant or, if the fees and/or penalties result in a net charge to Participant, Participant agrees to remit payment to Company within 30 days of invoice receipt. Any revenue due to a Participant pursuant to this agreement will first be applied to any amounts due from Customer as a result of Participant's service under Schedule MVDR. For example, if a Participant has failed to pay any penalties due under Schedule MVDR, the Company shall retain future revenue due Participant to offset said penalties. If any fees and/or penalties are imposed by MISO on the Company related to participation, Company shall retain the greater of (1) 5% of MISO revenues netted against any fees and/or penalties or (2) $500 for that billing period.

C. TERMINATION

Company may terminate per the MVDR Agreement participation in Rider Schedule MVDR if MISO determines that Participant is precluded from or ineligible to participate as a MISO DR product, for failure to adequately perform, and/or for failure to pay any MISO-imposed net charges, fees, and/or penalties imposed on the Company subject to the provisions of Sections IV(A) and IV(B), or for failure to comply with the provisions of Schedule MVDR.

D. CHANGES TO OFFERS

Participant may revise its standing Demand Response Offer twice per calendar month. The Company will impose a $50 charge for each subsequent change after the second change that occurs within the same calendar month. For system reliability purposes, an offer update may be completed without the incurrence of the $50 charge if the offer update includes changes only to the availability of the DR resource.

V. CONTRACT PERIOD

Participation in Rider Schedule MVDR will have an initial minimum term of one (1) year from the later of (1) the Effective Date within the MVDR Agreement or (2) the month and year the DR resource type(s) are registered with MISO and fully participating in the market. As per the MVDR Agreement, participation after the initial minimum term of one (1) year is satisfied will be renewed on an annual basis unless and until Company or Participant provides appropriate notice of cancellation.

Effective: ~~August~~September 28, 2020

ENTERGY LOUISIANA, LLC
FORMULA RATE PLAN RIDER SCHEDULE FRP-1
RATE ADJUSTMENTS

I. APPLICABILITY

This Rider is applicable under the regular terms and conditions of the Company to all Customers served under any retail electric Rate Schedule* and/or Rider schedule.* The FRP rate applicable to a specific Customer shall be determined by either the base rate schedule(s) applicable to the customer's geographic location (i.e., Legacy ELL Service Area or Legacy EGSL Service area) or, where applicable, the base rate schedule(s) elected by the Customer.

II. NET MONTHLY RATE

The Net Monthly Bill or Monthly Bill calculated pursuant to each applicable retail rate schedule* and/or rider schedule* on file with the Louisiana Public Service Commission will be adjusted monthly by the appropriate percentage of applicable Base Rate Revenues, before application of the monthly fuel adjustment.

*Excluded Schedules: AFC-L, AFC-G, AFC, AMSOO, ASPS-G, B-L, CM-G, Contract Minimums, CS-L, CS-L Rider 1, DTK, EAC, EAPS-L, EAPS-G, EECR-PE, EECR-QS-L, EECR-QS-G, ECS-L (Curtailable Load), EECS-L, EEIS-G, EER-L, EER-G, EEDBP, EIS-G, EIS-I-G, ERDRS-G, FCA (1,3,4,5), Facilities Charges, FIORE-L, FIORE-G, FA, FR-1-G, FSC-ELL, FSCII-ELL, FSCIII-ELL, FSC-EGSL, FSCII-EGSL, FSCIII-EGSL, FSPP, FT, Incremental Load under LCOP, LIS-L Rider 2, LIPS-L Rider 2, LQF-PO-G, MS, MVDR, MVER-L, MVER-G, NFRPCEA-L, NFRPCEA-G, OBP, PPS-1-L, QFSS-L, RCL, REP, RPCEA-L, RPCEA-G, RRD-V-G, RRD-VI-G, SCO-L, SCO-G, SCOII-L, SCOII-G, SCOIII-L, SCOIII-G, SLGO-L, SLGR-L, SMQ-G, SQF-L, SQF-G, SSTS-G, and applicable Special Contracted Rates.

Entergy Louisiana, LLC
Formula Rate Plan (Rider FRP)
Rate Development Formula
For the Test Year Ended December 31, 2019

Ln No.	Rate Class (1)	Legacy FRP Rates (2)	Incremental ELL FRP Rate for FRPxMCRMxTRAM (3)	Rider FRP Rate for MCRM (4)	Rider FRP Rate for TRAM (5)	Total ELL FRP Rate Adj. (6)
1	ELL- Residential	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
2	ELL- Small General Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
3	ELL- Large General Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
4	ELL- Exper Curtailable Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
5	ELL- Large Industrial Power Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
6	ELL- Large Load, High Load Factor Power Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
7	ELL- Large Industrial Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
8	ELL- Lighting	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
9	EGSL- Residential	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
10	EGSL- Small General Service	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
11	EGSL- General Service	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
12	EGSL- Large Power Service	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
13	EGSL- High Load Factor Service	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
14	EGSL- Municipal Water Pumping Service	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
15	EGSL- Street & Area Lighting	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%

Notes:
(1) Excludes schedules specifically identified in this Rider FRP.
(2) See Attachment A, Page 2 Column E.
(3) See Attachment A, Page 2 Column I.
(4) See Attachment A, Page 2 Column M.
(5) See Attachment A, Page 2 Column Q.
(6) Sum of column 2, 3, 4 and 5; % applied to customer applicable revenue.

Effective: September 28, 2020

ENTERGY LOUISIANA, LLC
FORMULA RATE PLAN RIDER SCHEDULE FRP-1
RATE ADJUSTMENTS

I. APPLICABILITY

This Rider is applicable under the regular terms and conditions of the Company to all Customers served under any retail electric Rate Schedule* and/or Rider schedule.* The FRP rate applicable to a specific Customer shall be determined by either the base rate schedule(s) applicable to the customer's geographic location (i.e., Legacy ELL Service Area or Legacy EGSL Service area) or, where applicable, the base rate schedule(s) elected by the Customer.

II. NET MONTHLY RATE

The Net Monthly Bill or Monthly Bill calculated pursuant to each applicable retail rate schedule* and/or rider schedule* on file with the Louisiana Public Service Commission will be adjusted monthly by the appropriate percentage of applicable Base Rate Revenues, before application of the monthly fuel adjustment.

*Excluded Schedules: AFC-L, AFC-G, AFC, AMSOO, ASPS-G, B-L, CM-G, Contract Minimums, CS-L, CS-L Rider 1, DTK, EAC, EAPS-L, EAPS-G, EECR-PE, EECR-QS-L, EECR-QS-G, ECS-L (Curtailable Load), EECS-L, EEIS-G, EER-L, EER-G, EEDBP, EIS-G, EIS-I-G, ERDRS-G, FCA (1,3,4,5), Facilities Charges, FIORE-L, FIORE-G, FA, FR-1-G, FSC-ELL, FSCII-ELL, FSCIII-ELL, FSC-EGSL, FSCII-EGSL, FSCIII-EGSL, FSPP, FT, Incremental Load under LCOP, LIS-L Rider 2, LIPS-L Rider 2, LQF-PO-G, MS, MVDR, MVER-L, MVER-G, NFRPCEA-L, NFRPCEA-G, OBP, PPS-1-L, QFSS-L, RCL, REP, RPCEA-L, RPCEA-G, RRD-V-G, RRD-VI-G, SCO-L, SCO-G, SCOII-L, SCOII-G, SCOIII-L, SCOIII-G, SLGO-L, SLGR-L, SMQ-G, SQF-L, SQF-G, SSTS-G, and applicable Special Contracted Rates.

Entergy Louisiana, LLC
Formula Rate Plan (Rider FRP)
Rate Development Formula
For the Test Year Ended December 31, 2019

Ln No.	Rate Class (1)	Legacy FRP Rates (2)	Incremental ELL FRP Rate for FRPxMCRMxTRAM (3)	Rider FRP Rate for MCRM (4)	Rider FRP Rate for TRAM (5)	Total ELL FRP Rate Adj. (6)
1	ELL- Residential	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
2	ELL- Small General Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
3	ELL- Large General Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
4	ELL- Exper Curtailable Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
5	ELL- Large Industrial Power Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
6	ELL- Large Load, High Load Factor Power Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
7	ELL- Large Industrial Service	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
8	ELL- Lighting	33.1010%	29.9381%	-2.2330%	-5.8603%	54.9458%
9	EGSL- Residential	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
10	EGSL- Small General Service	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
11	EGSL- General Service	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
12	EGSL- Large Power Service	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
13	EGSL- High Load Factor Service	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
14	EGSL- Municipal Water Pumping Service	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%
15	EGSL- Street & Area Lighting	31.6183%	29.9381%	-2.2330%	-5.8603%	53.4631%

Notes:
(1) Excludes schedules specifically identified in this Rider FRP.
(2) See Attachment A, Page 2 Column E.
(3) See Attachment A, Page 2 Column I.
(4) See Attachment A, Page 2 Column M.
(5) See Attachment A, Page 2 Column Q.
(6) Sum of column 2, 3, 4 and 5; % applied to customer applicable revenue.

BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION

ORDER NO. U-35443

ENTERGY LOUISIANA, LLC, EX PARTE.

Docket No. U-35443, In re: Application for Authorization to Change Rates by Filing Market Valued Demand Response Rider Schedule MVDR.

(Decided at the September 16, 2020 Business and Executive Session.)

Background and Procedural History

On December 16, 2019, Entergy Louisiana, LLC ("ELL" or "the Company") filed an application ("Application") with the Louisiana Public Service Commission ("Commission") seeking Commission authorization to implement its proposed Market Value Demand Response Rider Schedule MVDR ("Schedule MVDR"). Notice of the Application was published in the Commission's Official Bulletin No. 1209, dated December 27, 2019. During the intervention period, the Louisiana Energy Users Group ("LEUG"), the Alliance for Affordable Energy ("the Alliance"), and the Advanced Energy Management Alliance ("AEMA") intervened.

Schedule MVDR was developed by ELL to facilitate Demand Response ("DR") participation in the markets operated by the Midcontinent Independent System Operator, Inc. ("MISO"). Schedule MVDR sets the terms and conditions under which end-use customers of ELL may participate in the MISO DR markets as well as outlining the requirements for Aggregators of Retail Customers ("ARCs") to participate in those same markets. Schedule MVDR, consistent with the Commission's existing rules, does not permit direct participation in the MISO wholesale markets by end-use customers and ARCs, but rather, ELL will serve as the Market Participant ("MP") in MISO on behalf of customers and ARCs taking service under the proposed tariff offering.

At the initial status conference on February 10, 2020, the parties agreed to a procedural schedule and a hearing date of August 21, 2020. On March 18, 2020, the Tribunal issued a notice suspending the entire procedural schedule, in light of Proclamation Number 30 JBE 2020,[1] which suspended all legal deadlines until April 13, 2020. This suspension of legal deadlines was subsequently extended by Governor Edwards through additional proclamations[2] and later extended

[1] Proclamation Number JBE 2020-30, *Additional Measures for [COVID-19] Public Health Emergency*.
[2] Those subsequent Proclamations were: Proclamation Number 41 JBE 2020, *State of Emergency for COVID-19 Extension of Emergency Provisions* (signed April 2, 2020), which extended the suspension of legal deadlines until April 30, 2020; Proclamation Number 52 JBE 2020, *Renewal of State of Emergency for COVID-19 Extension of Emergency Provisions* (signed April 30, 2020), which extended the suspension of legal deadlines until May 15, 2020;

again to July 6, 2020, by the Louisiana State Legislature.[3] On April 23, 2020, ELL and the Commission Staff filed a Joint Unopposed Motion to Reset Procedural Schedule, requesting a hearing date to be determined by the administrative law judge after the end of legal suspensions. The Tribunal granted the motion.

On May 1, 2020, LEUG filed the Direct Testimony of James Dauphinais; AEMA filed the Direct Testimony of Katherine Hamilton; and the Commission Staff filed the Direct Testimony of William Barta. On May 28, 2020, the Commission Staff filed the Cross-Answering Testimony of William Barta.

On July 9, 2020, ELL filed an Unopposed Motion to Extend Procedural Schedule, which was granted by the Tribunal on the same day. On July 31, 2020, ELL filed an Unopposed Motion to Suspend Procedural Schedule, requesting that all remaining procedural deadlines be suspended. The Tribunal granted the motion.

On August 21, 2020, ELL and the Commission Staff filed a Joint Motion for the Scheduling of Hearing on Uncontested Stipulated Settlement ("Joint Motion"), requesting a stipulation hearing on September 2, 2020. The motion was accompanied by an Uncontested Proposed Stipulated Settlement term sheet and the supporting testimonies of Elizabeth Ingram and William Barta. The Joint Motion was granted, and a stipulation hearing was scheduled for September 2, 2020.

Jurisdiction and Applicable Law

The Commission has been vested with the authority to regulate public utilities and common carriers and exercises jurisdiction in this proceeding pursuant to Article IV, Section 21(B) of the Louisiana Constitution of 1974, which provides in pertinent part:

> The commission shall regulate all common carriers and public utilities and have such other regulatory authority as provided by law. It shall adopt and enforce reasonable rules, regulations, and procedures necessary for the discharge of its duties, and shall have other powers and perform other duties as provided by law.

Uncontested Stipulated Settlement

After discovery and submission of direct and cross-answering testimony by the parties, ELL, the Commission Staff, and LEUG negotiated and subsequently executed an Uncontested

---

and Proclamation Number 59 JBE 2020, *Renewal of State of Emergency for COVID-19 Extension of Emergency Provisions* (signed May 14, 2020), which extended the suspension of legal deadlines until June 5, 2020.

[3] *See* La. R.S. 9:5830(A) (Acts 2020, No. 162) (suspending/extending deadlines in legal proceedings that were suspended by Proclamation Number JBE 2020-30 and any extensions thereof until July 6, 2020, if such deadlines would have otherwise expired during the time period of March 17, 2020, through July 5, 2020).

Stipulated Settlement ("Stipulated Settlement"), resolving all disputed issues among the parties to this proceeding, which was filed into the docket on August 21, 2020. The Stipulated Settlement was not opposed by the Alliance or AEMA. The Stipulated Settlement was presented at a stipulation hearing on September 2, 2020, pursuant to Rule 6 of the Commission's Rules of Practices and Procedures. The Stipulated Settlement is entered into by ELL, LEUG, and the Commission Staff. The Alliance and AEMA do not oppose the provisions of the Stipulated Settlement. The terms of the Stipulated Settlement, which resolves all issues in this docket, provide that:

1. ELL will be authorized to implement the proposed, voluntary Market Value Demand Response Rider Schedule ("Schedule MVDR"), attached hereto as Exhibit A. This Term Sheet sets forth the terms upon which the Commission approves ELL's implementation of Schedule MVDR, in accordance with the Commission's ARC General Order,[4] and the General Order on Tariff Filings,[5] and as a compromise of disputed issues and positions set forth in testimony filed by parties in this proceeding Attached hereto as Exhibit B is a "redline" of proposed Schedule MVDR that is reflective of modifications made to the proposed Schedule to reflect the terms adopted herein.
2. ELL shall be the sole entity eligible to serve as Market Participant under Schedule MVDR.
3. ELL shall be authorized to assess participants in Schedule MVDR an administrative fee of five percent (5%) of monthly Midcontinent Independent System Operator, Inc. ("MISO") net revenues. Any changes to the five percent (5%) fee must be approved by the Commission.
4. The LPSC has previously approved recovery of MISO charges and revenues through the Company's retail ratemaking mechanisms, including ELL's Fuel Adjustment Clause ("FAC") and Formula Rate Plan ("FRP").[6] Consistent with that

---

4 *See* General Order 3-7-2019 (R-34948), dated March 7, 2019, *In re: Rulemaking to study the implications of participation of Aggregators of Retail Customers to determine whether, and under what conditions, such activity should be allowed in the Louisiana Public Service Commission's jurisdiction* ("ARC General Order").

5 *See* General Order 7/1/2019, issued in Docket No. R-34738, *In re: Proceeding to Establish Rules Regarding Electric Utility Tariff Filings and Related Review, Including Site Specific Rate Filings.*

6 *See, e.g.*, General Order 11/4/2013, issued in Docket No. U-32675, *In re: Joint implementation filing and request for associated approval addressing certain implementation, integration, and other issues regarding EGSL and ELL joining the Midwest Transmission System Operator, Inc. Regional Transmission Organization, as determined by the LPSC in Order No. U-32148 to be in the public interest subject to certain contingencies and the satisfaction of conditions*; General Order 7/6/2018, issued in Docket No. R-33391, *In re: Commission Consideration of*

previously approved recovery, any MISO charges or revenues received from MISO due to customer participation in MVDR will be passed through the Company's retail ratemaking mechanisms, including ELL's FAC and FRP. Any charges or credits provided by ELL to MVDR participants will be recovered through the mechanism approved for the MISO charges and revenues supporting those charges and credits to MVDR participants, net of the 5% administrative fee identified in paragraph 3. The FRP adjustment will not be applied to any charges or credits provided to MVDR participants. To the extent that the prudently-incurred costs of administering Schedule MVDR exceed the amount collected by the Company in administrative fees, all such prudently-incurred costs shall be eligible for recovery through normal ratemaking mechanisms, including but not limited to the Company's FRP. Likewise, to the extent that the prudently-incurred costs of administering Schedule MVDR is less than the amount collected by the Company in administrative fees, all such excess amounts shall be included in normal ratemaking mechanisms, including but not limited to the Company's FRP.

5. The Parties agree that the following language from Schedule MVDR: "Rider Schedule MVDR is not available to any Participant with respect to non-firm load already under contract with the Company as interruptible or curtailable service, or otherwise participating in any other Company demand response effort, unless that Participant agrees to move such load to service under this Rider Schedule MVDR," is not intended to prohibit, and will not have the effect of prohibiting, customers who participate or have participated in ELL's energy efficiency program offerings from being eligible for Schedule MVDR, provided that such customers fulfill the eligibility requirements for Schedule MVDR.
6. The Company agrees to utilize the draft MVDR Customer Agreement form attached to this Term Sheet as Exhibit C when enrolling customers in Schedule MVDR, provided however that the Company retains the right to negotiate and agree to modifications to the MVDR Customer Agreement form.

Potential Rules and Parameters for Participation in the Midcontinent Independent System Operator, Inc. ("MISO") Annual Planning Resource Auction ("PRA").

7. Except as otherwise expressly stated herein, this Term Sheet shall have no precedential effect in any other proceedings involving issues similar to those resolved herein and shall be without prejudice to the right of any party to take any position on any such similar issue in future proceedings, including FRP proceedings, base rate proceedings, rulemakings or in other regulatory proceedings or appeals therefrom.

Commission Consideration

The Uncontested Stipulated Settlement was considered at the Commission's September 16, 2020 Business and Executive Session. On motion of Commissioner Skrmetta, seconded by Vice Chairman Greene, and unanimously adopted, the Commission voted to adopt the Uncontested Stipulated Settlement filed into the record on August 21, 2020.

IT IS, THEREFORE, ORDERED THAT:

1) The Uncontested Stipulated Settlement filed on August 21, 2020, between ELL, LEUG, and Commission Staff, is adopted.
2) This Order is effective immediately.

BY ORDER OF THE COMMISSION
BATON ROUGE, LOUISIANA
September 28, 2020

/S/ MIKE FRANCIS
DISTRICT IV
CHAIRMAN MIKE FRANCIS

/S/ CRAIG GREENE
DISTRICT II
VICE CHAIRMAN CRAIG GREENE

/S/ FOSTER L. CAMPBELL
DISTRICT V
COMMISSIONER FOSTER L. CAMPBELL

/S/ LAMBERT C. BOISSIERE, III
DISTRICT III
COMMISSIONER LAMBERT C. BOISSIERE, III

BRANDON M. FREY
SECRETARY

/S/ ERIC F. SKRMETTA
DISTRICT I
COMMISSIONER ERIC F. SKRMETTA

BEFORE THE PUBLIC SERVICE COMMISSION
OF
THE STATE OF MISSISSIPPI

ENTERGY MISSISSIPPI, LLC
EC123008200

DOCKET NO. 2019-UN-082

IN RE: NOTICE OF INTENT OF ENTERGY MISSISSIPPI, LLC TO CHANGE RATES BY FILING MARKET VALUED DEMAND RESPONSE RIDER

ORDER

Entergy Mississippi, LLC ("Entergy Mississippi," "EML," or the "Company") filed a Notice of Intent pursuant to Section 77-3-37 of the Mississippi Code of 1972, as amended, and Procedural Rule RP 9.100.1 of the Mississippi Public Service Commission's (the "Commission") Public Utilities Rules of Practice and Procedure ("Procedural Rules"), giving notice of Entergy Mississippi's intent to implement a routine change in rates by filing Market Valued Demand Response Schedule MVDR-1 ("Schedule MVDR-1"). The Commission, upon recommendation of the Mississippi Public Utilities Staff ("Staff"), approves Schedule MVDR-1 and finds as follows:

1. On May 24, 2019, Entergy Mississippi filed its Notice of Intent to implement a routine change in rates by filing Market Valued Demand Response Schedule MVDR-1. In support of the Notice of Intent, Entergy Mississippi filed as an Attachment the pre-filed Direct Testimony of Mr. D. Andrew Owens.

2. The Staff conducted an extensive review of Entergy Mississippi's filing and has had the benefit of information provided by the Company in the discovery process.

3. The Commission, having considered the filing and all evidence submitted, including all testimony and documents filed with the Commission, and being fully advised in the premises, and upon the recommendation of the Staff, finds as follows.

4. The Commission finds that Schedule MVDR-1, which is attached to this Order as Exhibit A, defines the parameters under which EML's end-use customers can participate in the Midcontinent Independent System Operator Inc.'s ("MISO") demand response ("DR") markets as well as how Aggregators of Retail Customers ("ARCs") must operate in those same MISO DR markets if they wish to engage with Entergy Mississippi's customers to provide such services to MISO.[1] Schedule MVDR-1 outlines which customers are eligible to participate in the tariff, defines technical terms, and describes how Schedule MVDR-1 will work for participants in the tariff ("Participants"), which includes both end-use customers as well as ARCs that aggregate one or more end-use retail customers of Entergy Mississippi.

5. The Commission further finds that Schedule MVDR-1 is the only vehicle through which end-use retail customers and/or ARCs will be permitted to participate as DR resources in the MISO wholesale market. Entergy Mississippi will be the sole Market Participant ("MP") in MISO for all DR resources provided by Participants in EML's service territory.

6. As discussed in Schedule MVDR-1, the Commission finds that all Participants must execute an MVDR Agreement with EML. A model agreement is attached to this Order as Exhibit B.

7. Mr. Owens testified that DR resources should be implemented in a way that is fair to EML's customers, administered under the Commission's oversight, and in careful coordination with EML's and the Commission's efforts to comprehensively provide reliable and safe electric service to Mississippi residents at the lowest reasonable cost.

8. Mr. Owens also testified that when end-use customers and/or ARCs register with MISO, there is expected to be an effect on all customer bills because MISO treats DR resources

[1] On March 5, 2019, the Commission, *sua sponte*, issued an Order prohibiting third-party ARCs from registering MPSC-jurisdictional retail customers or participating in wholesale markets on such retail customers' behalves in Docket 2018-AD-141. The prohibition is currently set to expire on September 30, 2019.

as available capacity and energy depending on the particular MISO DR product that is offered and sold into the MISO wholesale markets. Mr. Owens also notes that transparency, optimized planning, and accurate load forecasting are pillars of the planning process to ensure adequate supply and reliability, and affordable electric service. Direct participation of retail customers in Regional Transmission Organization DR markets or through ARCs, rather than through regulated utilities, could adversely impact these goals, which could ultimately result in increased costs to all customers.

9. Mr. Owens further testifies that EML, as a Load Serving Entity, is the most appropriate MP for DR resources in Mississippi because the utility can manage risks and the retail regulator retains appropriate oversight.

10. The Commission has reviewed the testimony of Mr. Owens and agrees with the above-cited reasons for approval of Schedule MVDR-1.

11. The Commission finds it appropriate to exercise its jurisdiction to regulate end-use retail customers and/or ARCs as DR resources in the MISO wholesale market, to require transparency into their activities, and to require that those activities be coordinated with the Commission and the electric utility.

12. The Commission finds that Schedule MVDR-1 is consistent with the public interest because it helps to ensure fairness and transparency in the way that end-use retail customers and/or ARCs participate as DR resources in the MISO wholesale market.

13. The Commission finds that Schedule MVDR-1 is just and reasonable, consistent with applicable law and the rules of this Commission, and should be allowed to go into effect as provided for herein.

IT IS, THEREFORE, ORDERED that Schedule MVDR-1 is hereby approved and ordered into effect. This Order shall be deemed issued on the day it is served upon the parties herein by the Executive Secretary of this Commission who shall note the service date in the file of this Docket.

COMMISSION VOTE

Chairman Brandon Presley voted	Aye ✓	Nay ____
Vice Chairman Cecil Brown voted	Aye ✓	Nay ____
Commissioner Samuel F. Britton voted	Aye ✓	Nay ____

SO ORDERED, this the 10th day of September 2019.

MISSISSIPPI PUBLIC SERVICE COMMISSION

BRANDON PRESLEY, CHAIRMAN

CECIL BROWN, VICE CHAIRMAN

SAMUEL F. BRITTON, COMMISSIONER

ATTEST: A True Copy

Katherine Collier, Executive Secretary

Effective this the 10th day of September 2019

MISSISSIPPI PUBLIC SERVICE COMMISSION

EXHIBIT A

ENTERGY MISSISSIPPI, LLC	MISSISSIPPI PUBLIC SERVICE COMMISSION
	P.S.C. Schedule No. I-27.25
Date Filed: May 24, 2019	
Date to be Effective: September 30, 2019	
Docket No.: 2019-UN-082	Schedule Consists of: Five Pages

MARKET VALUED DEMAND RESPONSE SCHEDULE (MVDR-1)

I. AVAILABILITY

This Market Valued Demand Response Schedule (Schedule MVDR) is an optional service that provides an opportunity for a qualifying "Customer" with firm load(s) or an "ARC"[1] (either or both of which may be sometimes referred to herein as "Participant") to participate as one or more "DR" resources in "MISO" wholesale markets. Participant must execute a MVDR Agreement to facilitate curtailment of a specified amount of firm electric load for a single qualifying meter (or multiple meters) through the Company acting as the "MP." Customers or ARCs shall not participate as a DR resource in "MISO" wholesale markets except through this Schedule MVDR or other Company-implemented DR effort.

Schedule MVDR is not available to any Participant with respect to non-firm load already under contract with the Company as interruptible or curtailable service, or otherwise participating in any other Company demand response effort, unless that Participant agrees to move such load to service only under this Schedule MVDR. A Participant who has executed an MVDR Agreement is prohibited from taking any temporary, standby, back-up, and/or maintenance service for such load during any DR Event that occurs per Schedule MVDR.

Customers with "BTMG" at a specific Customer location using net metering or a related tariff as a "QF" are not eligible to take service under Schedule MVDR.

II. DEFINITIONS*

MISO: Midcontinent Independent System Operator, Inc.

BPMs: MISO Business Practice Manuals currently in effect.

MISO FERC Tariff: MISO's current FERC-approved tariff and associated schedules.

ARC: Aggregator of Retail Customers.

BTMG: Behind-the-Meter Generation.

Curtailment Amount: The amount of firm load that the Participant reduces relative to the Consumption Baseline.

Customer: A retail electric customer of Entergy Mississippi, LLC.

Firm MVDR Demand: The amount of firm load that the Participant agrees not to exceed during a DR Event that occurs per Schedule MVDR.

DR: Demand Response.

DR Event: A MISO-initiated event requiring the reduction of demand by a Participant in MISO's markets providing one or more DR products.

[1] Terms in quotation marks are defined in Section II. of this Schedule.

(Continued on reverse side)

Demand Response Offer: A standing offer by a Participant to the Company to provide a DRR Type 1, DRR Type 2, EDR, and/or LMR in the MISO markets. This offer will be submitted to MISO by the Company in the MISO Day Ahead Market, Real Time Market, LMR offer process, and/or EDR offer process as applicable to the Participant's DR product type(s).

DRR: Demand Response Resource.

EDR: Emergency Demand Response.

LMR: Load Modifying Resource.

MP: Market Participant. The Company shall be the sole MP in MISO for any and all DR resources provided by Participant within the Company's service territory.

QF: Qualifying Facility as per the Public Utility Regulatory Policies Act of 1978 as may be amended from time to time.

* For further detail on existing definitions, as well as definitions for other capitalized terms throughout this schedule, refer to MISO BPMs.

III. GENERAL PROVISIONS

A. DESCRIPTION

Participation in Schedule MVDR offers Participants the opportunity to authorize the Company, acting as the MP, to register Participant's "Curtailment Amount" as one or more MISO wholesale DR products ("DRR," "EDR," and/or "LMR") as specified in the executed MVDR Agreement in order to participate in the MISO day-ahead and/or real-time energy and operating reserve markets, as well as MISO's capacity market, if applicable. Participant will be compensated as per Schedule MVDR with MISO revenue resulting from participation as one or more MISO wholesale DR products. The Company shall be the sole MP in MISO for any and all DR resources provided by Participant within the Company's service territory.

Participation shall not begin until a MVDR Agreement has been executed and all applicable MISO registration requirements have been completed and certified by MISO. Participant must assist and coordinate with the Company to comply with all applicable MISO requirements. DR resource designations available to a Customer or to an ARC acting on behalf of one or more Customers include DRR Type 1 and Type 2, EDR, LMR-DR, and/or LMR-BTMG. The MVDR Agreement will specify which DR type(s) and combinations thereof, if applicable, Participant has agreed to provide.

B. CURTAILMENT

1. For DRR Type 1 and DRR Type 2 resources, Participant must provide the Company a minimum load reduction of the greater of (a) 1,000 kilowatts ("kW"), which can be aggregated from multiple Customer locations in accordance with the currently-effective MISO FERC Tariff and/or as described in the MISO "BPMs" or (b) the minimum specified in the currently-effective MISO FERC Tariff and/or as described in the MISO BPMs.
2. For EDR, LMR-DR, and LMR-BTMG resources, Participant must provide the Company a minimum load reduction of the greater of (a) 100 kW or (b) the minimum specified in the currently-effective MISO FERC Tariff and/or described in the MISO BPMs.

 (Continued on next page)

3. Participant must specify the firm electric load reduction as a Curtailment Amount below the Consumption Baseline or may limit demand to a "Firm MVDR Demand." The method to compute the amount of load reduction for a "DR Event" is specified in the MVDR Agreement.
4. Each Customer location shall provide a minimum load reduction of 100 kW.

C. METERING AND COMMUNICATION

Customer or each retail Customer(s) aggregated by an ARC must have an interval data recording meter capable of participating in Schedule MVDR. If the Customer location does not have the appropriate equipment already installed, such equipment will be installed by the Company at Participant's expense. All metering and communication equipment installed for Participant necessary to take service under Schedule MVDR is and will remain the property of Company.

D. DAILY PROCESS

As contemplated in the MVDR Agreement, participation by a Customer or ARC will be permitted on any day as per applicable MISO requirements. Participant's daily offer will be submitted to the Company to be included in the Company's daily offer to MISO. At the time of initial registration, the Participant will establish a default "Demand Response Offer" that will remain valid unless the Participant modifies any parameter of the resource offer by the deadline as established in the MVDR Agreement. Participant shall provide accurate availability information, including timely update to Company for when any planned outage or similar event is scheduled.

E. REGISTRATION AND CAPACITY MARKET PROCESS

Participant must submit all information, including but not limited to real power testing, required by MISO for market registration and, if applicable, capacity market participation at least 30 days before the relevant MISO submission deadlines. However, for DRR resources, Participant must submit all information no later than 60 days prior to the applicable MISO deadline for the quarterly commercial model update in which Participant wants to register as a DRR.

F. MISO PERFORMANCE REQUIREMENTS

Participant must comply with all MISO requirements as stated in MISO's currently-effective FERC Tariff and as described in the MISO BPMs, including, but not limited to, the Demand Response BPM and the Resource Adequacy BPM.

G. AGGREGATION OF RETAIL CUSTOMER LOAD

An ARC aggregating one or more Customer DR resources shall be subject to all requirements set forth in this Schedule MVDR. In addition, the ARC must identify in the MVDR Agreement each Customer location being aggregated and provide all necessary information required by MISO for participation and certification as the DR type(s) selected. No Customer location(s) shall be represented by more than one ARC taking service under Schedule MVDR. No Customer location(s) may participate directly via Schedule MVDR and simultaneously through an ARC.

IV. MONTHLY BILLING

The Net Monthly Bill will be determined in accordance with the terms and calculations defined below and as per the MVDR Agreement.

 (Continued on next page)

A. MONTHLY SETTLEMENTS

1. For all DR resources, Company has the option to include on Customer's monthly electric bill or send a separate statement for the Customer's applicable MISO settlement amount (less 10% to cover Company's administrative costs); and any penalty for failure to perform as outlined in Paragraph B.

2. For any Customer location(s) participating via an ARC, Company will provide ARC with a monthly statement with applicable MISO settlement amount (less 10% to cover Company's administrative costs); and any penalty for failure to perform as outlined in Paragraph B. In instances of liability to Customer for any harm arising from the Customer's relationship with the ARC, including but not limited to breach of contract, any applicable fees/penalties will fall upon the ARC itself.

3. Any MISO revenues related to Customer location(s) participation as a MISO DR product including participation via an ARC will be netted first against any applicable fees and/or penalties assigned by MISO that are specific to that participation; but, in no event shall the Company's allocated share be reduced below zero. Credit to Participant for each month, if any, owed for participation as a MISO DR product shall be remitted within 30 days after the end of the month to allow time for settlement and/or any true-ups as may be necessary to reflect any changes in current or prior MISO settlements. Such credits will be subject to adjustments,if any, from changes to MISO settlements in accordance with the "MISO FERC Tariff" and BPMs. Company and Participant shall agree upon the monthly compensation method per the MVDR Agreement.

B. PENALTY FOR FAILURE TO PERFORM

Participant shall be responsible for any and all net charges, fees, and/or penalties imposed on the Company by MISO relating to participation in the MISO markets, except for those arising from the Company's gross negligence or failure to perform as directed by MISO. All fees and/or penalties imposed on the Company by MISO for a particular Participant will be netted against any MISO revenues payable to that Participant or, if the fees and/or penalties result in a net charge to Participant, Participant agrees to remit payment to Company within 30 days of invoice receipt. Any revenue due to a Participant pursuant to this agreement will first be applied to any amounts due from Customer as a result of Participant's service under Schedule MVDR. For example, if a Participant has failed to pay any penalties due under Schedule MVDR, the Company shall retain future revenue due Participant to offset said penalties. If any fees and/or penalties are imposed by MISO on the Company related to participation, Company shall retain the greater of (1) 10% of MISO revenues netted against any fees and/or penalties or (2) $500 for that billing period to recover the Company's administrative and related costs for determination and allocation of any fees and/or penalties.

C. TERMINATION

Company may terminate per the MVDR Agreement participation in Schedule MVDR if MISO determines that Participant is precluded from or ineligible to participate as a MISO DR product, for failure to adequately perform, and/or for failure to pay any MISO-imposed net charges, fees, and/or penalties imposed on the Company subject to the provisions of Sections III(A) and III(B), or for failure to comply with the provisions of Schedule MVDR.

D. CHANGES TO OFFERS

Participant may revise its standing Demand Response Offer twice per calendar month. The Company will impose a $50 charge for each subsequent change after the second

 (Continued on next page)

change that occurs within the same calendar month. For system reliability purposes, an offer update may be completed without the incurrence of the $50 charge if the offer update includes changes only to the availability of the DR resource.

V. CONTRACT BILLING

Participation in Schedule MVDR will have an initial minimum term of one (1) year from the latter of (1) the effective date within the MVDR Agreement or (2) the month and year the DR resource type(s) are registered with MISO and fully participating in the market. As per the MVDR Agreement, participation after the initial minimum term of one (1) year is satisfied will be renewed on an annual basis unless and until Company or Participant provides appropriate notice of cancellation.

Exhibit B

MVDR AGREEMENT

This Market Valued Demand Response ("MVDR") Agreement is made and entered into on _Month Day, Year_ ("Effective Date"), by and between _Legal Entity Name of Customer or ARC_, a ____________________ corporation ("Participant") and Entergy Mississippi, LLC, a Texas limited liability company ("Company") (each a "Party," and collectively the "Parties").

WHEREAS, Participant wishes to enter into an MVDR Agreement with Company for service available under Company's Schedule MVDR-1 ("Schedule MVDR"), or any successor schedule approved by the Mississippi Public Service Commission, in order to provide one or more type(s) of demand response ("DR") product(s) in the Midcontinent Independent System Operator, Inc. ("MISO") wholesale markets.

WHEREAS, as defined for purposes of Schedule MVDR and this Agreement, Participant includes either one or more qualifying Customer Point(s) of Delivery with firm load(s) or an Aggregator of Retail Customers ("ARC") who aggregates one or more qualifying Customer Point(s) of Delivery with firm load(s) for the sole purposes of providing a DR resource(s) to Company for participation in MISO's wholesale markets. Customer Point(s) of Delivery with firm load(s) are listed in **Attachment A**.

NOW, THEREFORE, for and in consideration of the mutual covenants set forth herein, the Parties agree as follows:

ARTICLE I. GENERAL TERMS AND CONDITIONS

A. Definitions. Schedule MVDR refers to applicable terms that are, in some cases, further defined in the MISO Business Practice Manuals ("BPMs") currently in effect and/or MISO FERC Tariff. Definitions contained in Schedule MVDR, Company's current Service Policy, MISO BPMs, and MISO's FERC-approved tariff are incorporated herein by reference.

B. Timing. Provision of Participant's DR resource(s) in MISO and service under Schedule MVDR shall commence upon the later of (1) the Effective Date of this Agreement, (2) installation and operational readiness of required electric metering and communication equipment and collection of any data required in the registration process, and/or (3) full acceptance of the DR resource(s) registration and offer by MISO. Timing of registration and full participation by DR resource(s) in MISO's wholesale markets will be subject to MISO's planning cycles and normally-scheduled market model updates in accordance with MISO BPMs and the MISO FERC Tariff.

C. Communications. Company may utilize either telephone or electronic communication as the primary means to notify Participant of events and to process updates. This mechanism for communication may be altered at the sole discretion of Company. Participant will be responsible for providing its own Internet access, a phone number, and a dedicated email address to be used for communications from Company. Participant is responsible for notifying Company in the event that the agreed-upon communication method is temporarily unavailable and will provide Company with an alternate form of communication. Participant must provide and maintain 24-hour contact information.

D. Metering. If Participant does not have an adequate interval data recording electric meter capable of providing the load metering frequency and telemetry required by Company and by MISO in the applicable BPM for each participating Point of Delivery or a more frequent interval, adequate metering will be installed by Company at the Participant's expense before participation may begin.

E. Additional Equipment. As may be necessary for certain DR resource types, Participant is responsible for installing and maintaining any necessary equipment, telemetry, and communications capabilities to facilitate provision of any DR resources in the MISO market in conjunction with Schedule MVDR and this Agreement.

F. Testing. Participant must demonstrate load reduction capability as specified by MISO's applicable requirements in the applicable BPM and MISO FERC Tariff.

ARTICLE II. <u>DRR TYPES I AND II ENERGY MARKET PROCESS</u>

A. Default Demand Response Offer. Participant will establish a default Demand Response Offer consistent with applicable MISO requirements that will be submitted by Company to MISO in the MISO Day-Ahead and Real-Time Markets.

B. Updates to Demand Response Offer Received by Company's Deadline for Day-Ahead Market Participation. Participant may update the parameters of its Demand Response Offer. In order to be incorporated into the Day-Ahead Market, Company must receive Participant's updated Demand Response Offer by 8:00 AM CPT the day before the Operating Day the offer update is to be effective. Unless otherwise requested by Participant, these updated Demand Response Offer parameters will be used for the Participant's Real-Time Market offer for the following day only. Updated Demand Response Offer parameters will be effective only for the specified day and will not replace the Participant's default Demand Response Offer going forward unless requested by Participant. Company may alter Participant's Demand Response Offer by increasing the resource's notice time to allow Company time to communicate MISO instructions to Participant.

C. Updates to Demand Response Offer Received after Company's Deadline for Day-Ahead Market Participation. Demand Response Offer changes received by Company after 8:00 AM CPT the day before the Operating Day will be included by Company in the resource's Real-Time Market offer. Company will employ commercially reasonable best efforts to reflect Demand Response Offer changes in the resource's Real-Time Market offer within 2 hours upon receipt of such a request. Updated Demand Response Offer parameters will be effective only for the specified day and will not replace the Participant's default Demand Response Offer going forward unless requested by Participant. Company may alter Participant's Demand Response Offer by increasing the resource's notice time to allow Company time to communicate MISO instructions to Participant.

D. Event Notification. For all DRR products, Participant must be capable of receiving and acknowledging start and stop instructions through electronic, telephonic, or other means to be determined by Company. For DRR Type II Resources, Participant must be capable of receiving and following MISO dispatch instruction, which will be relayed to Participant by Company through electronic means to be determined by Company.

E. Offered Demand Response Must be Achievable. Participant must specify a "Not Participating" status if load reduction is unavailable due to a forced or planned outage/shutdown or other physical operating restriction. If Participant cannot provide the offered load reduction amounts, Participant must immediately notify Company and submit an updated Demand Response Offer reflecting their physical capability. Participant's failure to immediately notify the Company of an inability to provide the offered load reduction amounts will subject Participant to the penalties described in Articles V and VIII, including suspension and/or termination of this MVDR Agreement. Participant's ability to provide the offered load reduction amount is subject to verification by Company and by MISO.

ARTICLE III. LMR AND EDR CURTAILMENT PROCESS

A. Default Demand Response Offer. Participant will establish a default Demand Response Offer consistent with applicable MISO requirements that will be submitted by Company to MISO in MISO's LMR or EDR offer processes, as applicable.

B. Updates to Demand Response Offer. Participant may update the parameters of its Demand Response Offer. For EDR resources, Participant must submit updated offers by 8:00 AM CPT the day before the Operating Day the offer change is to be effective. For LMR resources, Participant may update its Demand Response Offer at any time up to 6 days in advance of the Operating Day, and Company will employ commercially reasonable best efforts to reflect these changes in the resource's Demand Response Offer within 2 hours upon receipt of such a request. Company may alter Participant's Demand Response Offer by increasing the resource's notice time to allow Company time to communicate MISO instructions to Participant.

C. Event Notification. Company will notify Participant within 2 hours after receiving information on cleared Demand Response Offers for LMRs or EDRs from MISO regarding Participant's offer submitted through Company.

D. Offered Demand Response Must be Achievable. For LMRs, Participant must specify 0 MW available for LMRs if load reduction is unavailable due to a forced or planned outage/shutdown or other physical operating restriction. For EDRs, Participant must conform to EDR offer requirements, which currently includes setting the Maximum Demand Reduction as 0 MW or setting the Daily Availability as "No", if load reduction is unavailable due to a forced or planned outage/shutdown or other physical operating restriction. If Participant cannot provide the offered load reduction amounts, Participant must immediately notify Company and submit an updated Demand Response Offer reflecting Participant's physical capability. Participant's failure to immediately notify the Company of an inability to provide the offered load reduction amounts will subject Participant to the penalties described in Article V and VIII, including suspension and/or termination of Participant. Participant's ability to provide the offered load reduction amount is subject to verification by Company and by MISO.

ARTICLE IV. REGISTRATION AND PLANNING RESOURCE AUCTION ("PRA") PARTICIPATION

A. Registration. For DRRs, Participant must submit all information required by MISO for market registration at least 60 days prior to the applicable MISO deadline for the quarterly commercial model update in which Participant wants to register as a DRR. For LMRs and EDRs, Participant must submit all information required by MISO for registration at least 30 days prior to the applicable MISO deadline. All testing of LMRs as may be required by MISO, which will require interaction between Company and Participant, must be completed before the 30 day deadline.

B. PRA Participation. Participant may offer into the MISO PRA and be cleared by MISO as a Capacity Resource. PRA participation may be accomplished as an LMR (including dual registration as a DRR Type I, DRR Type II, or EDR) or as a DRR Capacity Resource.

C. Capacity Market Offer. Participant who desires to offer capacity in the MISO PRA must submit a PRA Offer to Company at least 30 days before the MISO PRA offer window closes. Company will submit such PRA Offer to MISO on Participant's behalf. If Participant's PRA Offer is cleared by MISO, then Participant must comply with the resulting obligations to make energy reduction available to MISO throughout the applicable capacity commitment period.

ARTICLE V. SETTLEMENTS & AVAILABILITY NOTIFICATION

A. Participant Charge for Updated Demand Response Offer Parameters. Participant may update its Demand Response Offer twice per calendar month at no additional cost to Participant. Company will impose a $50 charge for each subsequent change after the second change that occurs within the same calendar month: Offer updates may be completed without the incurrence of a $50 charge if the offer update only includes changes to the availability of the DR resource.

B. Load Reduction Obligation. Participant is obligated to reduce load as communicated by Company in accordance with MISO instructions. Deviations in any load reduction above or below the MISO instruction may result in penalties for failure to perform as described in the applicable MISO BPMs.

C. Baseline and Verification. Company will utilize the default calculated baseline method, as this term or its successor term is used in the applicable MISO BPMs, specified by MISO for DR resources providing energy to calculate the Consumption Baseline. As mutually agreed upon by Participant and Company, a Weather Sensitive Adjustment, as defined by MISO, may be incorporated. Alternatively, upon mutual agreement of Participant and Company, a custom baseline calculation acceptable to MISO may be used to determine the Consumption Baseline. The Consumption Baseline will be calculated as data is available and provided to MISO and Participant within the guidelines specified by MISO in the applicable BPMs. If available, the baseline load or an estimated baseline load will be communicated to Participant prior to the event.

D. Monthly Settlements. Participant will be eligible for compensation for energy-only load reduction for participating in an event when cleared and dispatched by MISO in the MISO Day-Ahead and Real-Time Markets and/or for qualifying amount of capacity registered and cleared as an LMR or as a DRR Capacity Resource in MISO's PRA. MISO settlement information will be used as the basis to establish Participant compensation. Subject to the provisions of Schedule MVDR, Company will retain 10% of the Monthly MISO Settlement Amount to cover Company's administrative costs. The Monthly MISO Settlement Amount is defined as any MISO revenues or charges related to participation under this MVDR Agreement received during the monthly billing period, including any applicable fees and/or penalties assigned by MISO that are specific to such participation. The treatment of net charges, fees, and/or penalties shall be as set forth in Article V(E). In no event shall Company's retained share be reduced below zero.

E. Penalty for Failure to Perform. Subject to Section IV(B) of Schedule MVDR, Participant shall be solely responsible for any and all net charges, fees, and/or penalties ("Penalties") imposed on Company by MISO relating to participation in the MISO markets, except for those arising from Company's gross negligence or failure to perform as directed by MISO. Any such payment to Company must be made within 30 days of invoice. If MISO imposes any Penalties on Company related to Participant's resource, they will be included in the Monthly MISO Settlement Amount. In addition to requiring Participant to pay the Penalties assessed by MISO, which are included in the Monthly MISO Settlement Amount, Company will retain or invoice Participant the greater of (1) 10% of the Monthly MISO Settlement Amount (as defined in Article V(D)) or (2) $500 for that billing period to recover Company's administrative and related costs for determination and allocation of any fees and/or penalties. If the Monthly MISO Settlement Amount is a net revenue less than $500, then Company will retain the Monthly MISO Settlement Amount and invoice Participant for the remainder of the $500 administrative fee owed to Company. If the Monthly MISO Settlement Amount is a net charge, then Company will invoice Participant for the Monthly MISO Settlement Amount plus the $500 administrative fee owed to Company. Participant's failure to perform consistent with this MVDR Agreement may also result in suspension or termination as set forth in Article VIII.

F. Timing of Compensation. Depending on applicable billing cycle(s), when DR events occur, and timing of MISO settlement statements, Participant's compensation under this Agreement may be delayed beyond 30 days.

G. Participant Operational Issues. Compensation is not provided for any load reduction planned or unplanned for any reason other than notification by Company to Participant of a cleared Demand Response Offer in the MISO Day-Ahead and Real-Time Markets and/or for qualifying amount of capacity registered and cleared as an LMR or as a DRR Capacity Resource in MISO's PRA. Participant shall not receive compensation for any MISO-called event during which Participant's firm load(s) is already reduced from the applicable Consumption Baseline due to planned or unplanned outage as a result of renovation, repair, refurbishment, maintenance outage, force majeure event, strike, or any event that otherwise affects Participant's normal operating condition.

H. Maintenance. Participant must inform Company in a timely manner of any planned or unplanned maintenance or other activities that will significantly change the Participant's available energy.

I. Interruption of Service. If electric service is interrupted during a MISO-called event, Company shall not be responsible for compensating Participant for energy reductions in excess of the amount received by Company from MISO. In addition, Participant will not be exposed to any charges for excessive energy from MISO. Electric service may be interrupted without limitation for accidents, adverse weather, equipment failures or malfunctions, or periods of involuntary load curtailment. Additionally, Participant shall not receive any compensation for any event excluded pursuant to the applicable MISO BPMs.

J. Daily Curtailment Limit. If Participant desires only one curtailment event to be permitted per day, then Participant must set offer parameters including minimum and maximum interruption durations and minimum non-interruption intervals to the appropriate values. Company will not otherwise restrict DR resource participation in MISO wholesale markets to only one curtailment event per day.

ARTICLE VI. ASSIGNMENT

Neither Party shall assign this MVDR Agreement or any portion thereof without the written consent of the other Party, and any attempted assignment or transfer without such written consent shall be of no force or effect. As to any permitted assignment: (a) reasonable prior notice of any such assignment shall be given to the other Party; and (b) any assignee shall expressly assume the assignor's obligations hereunder, unless otherwise agreed to by the other Party in writing.

ARTICLE VII. FORCE MAJEURE

For purposes of this MVDR Agreement, the term "Force Majeure" means any cause or event not reasonably within the control of the Party claiming Majeure, including, but not limited to, the following: acts of God, strikes, lockouts, or other industrial disturbances; acts of public enemies; orders or permits or the absence of the necessary orders or permits of any kind which have been properly applied for from the government of United States, the State of Mississippi, any political subdivision or municipal subdivision or any of their departments, agencies or officials, or any civil or military authority; unavailability of a fuel or resource used in connection with the generation of electricity; extraordinary delay in transportation; unforeseen soil conditions; equipment, material, supplies, labor or machinery shortages; epidemics; landslides; lightning; earthquakes; fires; hurricanes; tornadoes; storms; floods; washouts; drought; arrest; war; civil disturbances; explosions; breakage or accident to machinery, transmission lines, pipes or canals; partial or entire failure of utilities; breach of contract by any supplier, contractor, subcontractor, laborer or materialman; sabotage; injunction; blight; famine; blockade; or quarantine.

If either Party is rendered wholly or partly unable to perform its obligations under this MVDR Agreement because of Force Majeure, both Parties shall be excused from whatever obligations under this MVDR Agreement are affected by the Force Majeure (other than any obligations incurred prior to or separate from the Force Majeure event) and shall not be liable or responsible for any delay in the performance of, or the inability to perform, any such obligations for so long as the Force Majeure continues. The Party suffering an occurrence of Force Majeure shall, as soon as is reasonably possible after such occurrence, give the other Party written notice describing the particulars of the occurrence and shall use commercially reasonable efforts to remedy its inability to perform; provided, however, that the settlement of any strike, walkout, lockout or other labor dispute shall be entirely within the discretion of the Party involved in such labor dispute.

ARTICLE VIII. CONTRACT PERIOD, SCHEDULE AMENDMENTS, AND CONTRACT TERMINATION RIGHTS

The initial term of this MVDR Agreement will be for twelve months from the later of (1) the Effective Date of this MVDR Agreement or (2) the month and year the DR resource type(s) are registered with MISO and fully participating in the market, or for resources with a cleared PRA offer, through the end of the capacity commitment period. The capacity commitment period is defined as the planning period associated with MISO's capacity auction for which the Participant's DR product cleared. Participation will renew after the initial term on an annual basis until and unless Company or Participant gives notice of termination of this MVDR Agreement through a minimum of 60-day written notice. Notice may be given by either Party at least 60 days prior to the end of the initial term. In the event the Commission approves any amendment or replacement or successor to Schedule MVDR ("Amended Schedule"), and the provisions of the Amended Schedule conflict with the provisions of this MVDR Agreement, then the former shall govern.

If the Participant fails to comply with Schedule MVDR and/or this MVDR Agreement during a MISO-called event, Company and Participant will discuss methods to comply during future MISO-called events. If Participant fails to perform consistent with this MVDR Agreement including, but not limited to, failure to make timely payment of any net charges, fees, and/or penalties owed per Article V (D) and/or (E), or if there are system reliability issues created by the Participant's failure to adequately perform, Company may at its option suspend participation for 90 days or terminate this MVDR Agreement. Participation will also terminate immediately upon notification to Company from MISO that the Participant is no longer eligible to participate in MISO's wholesale markets. If this MVDR Agreement is terminated prior to the conclusion of a given capacity commitment, Participant will be required to replace the full amount of capacity.

ARTICLE IX. LIMITATION OF LIABILITY

To the fullest extent permitted by law, Participant and Company shall indemnify, defend and hold harmless the other Party and its parent company, subsidiaries, affiliates and their respective shareholders, officers, directors, employees, agents, representatives, successors and assigns (collectively, the "Indemnified Parties"), from and against any and all claims, actions, suits, proceedings, losses, liabilities, penalties, fines, damages, costs or expenses, including without limitation reasonable attorneys' fees ("Claim"), resulting from (a) any breach of the representations, warranties, covenants and obligations of either Party under this Agreement, (b) any act or omission of either Party, whether based upon that Party's negligence, strict liability or otherwise, in connection with the performance of this MVDR Agreement, or (c) any third party claims of any kind, whether based upon negligence, strict liability or otherwise, arising out of or connected in any way to either Party's performance or non-performance under this MVDR Agreement. Neither Party to this MVDR Agreement shall be liable for consequential damages of any kind related to performance or non-performance under this MVDR Agreement.

ARTICLE X. **DISPUTES**

In the event of any dispute between the Parties arising out of or relating to this MVDR Agreement, the Parties agree to seek informal dispute resolution or settlement prior to the institution of any other dispute resolution process. Should the informal dispute resolution process described herein be unsuccessful, the Parties agree that no written or oral representations made during the course of the attempted dispute resolution shall constitute a Party admission or waiver and that each Party may pursue any other legal or equitable remedy it may have available to it. The Parties agree that the existence of any dispute or the institution of any dispute resolution process (either formal or informal) shall not delay the performance of each Party's undisputed responsibilities under this MVDR Agreement.

ARTICLE XI. **ENTIRETY OF AGREEMENT**

This fully executed MVDR Agreement constitutes the entire and only agreement between the Parties hereto with reference to the subject matter hereof and supersedes all previous understandings whether written or oral.

ARTICLE XII. **NOTICES**

Any notice, consent, or other communication concerning this MVDR Agreement shall be properly given when deposited in the United States Mail, postage prepaid, registered or certified, and addressed as follows:

Attn:____________________	Attn: ____________________
____________________	Entergy Mississippi, LLC
____________________	308 E. Pearl St.
____________________	Jackson, MS 39201

PARTICIPANT	**ENTERGY MISSISSIPPI, LLC**
By: ____________________	By: ____________________
Signatory Title	*Signatory Title*
____________________	____________________
Attest: ____________________	Approved: ____________________
Signatory Title	*Signatory Title*
____________________	____________________
Date of Signature____________________	Date of Signature ____________________

ATTACHMENT A - Customer Point(s) of Delivery with firm load(s)

Acct #	**Service Address**	**Registration Options***							
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**

*Registration Options

1. DRR only
2. DRR Capacity Resource (includes a must offer obligation in the Day Ahead Market)
3. LMR/DRR dual-registration
4. EDR only
5. LMR/EDR dual-registration
6. DRR/EDR dual-registration
7. LMR only
8. DRR/LMR/EDR triple registration

For all resources, specify Curtailment Amount or Firm MVDR Demand

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Andrew Owens Sponsoring Witness: David E. Hunt Beginning Sequence No. LR884 Ending Sequence No. LR885

Question No.: TIEC 3-11 Part No.: Addendum:

Question:

In the absence of allowing a third-party to be the Market Participant:

a. Explain how ETI would track the costs and revenues associated with each Rider MVDR participant in each of the various MISO markets.

b. Would ETI require that any direct benefits be shared between ETI and each Rider MVDR participant? If so, state ETI' s revenue sharing proposal, and explain whether any benefits would be retained by ETI and/or flowed back to ETI' s other retail customers.

c. Explain ETI' s role in facilitating market participation to ARCs.

d. Explain how ETI would disaggregate the MISO submissions on behalf of the ARCs, retail MVDR customers, and ETI's other retail customers.

Response:

a. Per Schedule Market Valued Demand Response (“MVDR”) and the associated MVDR Agreement, both of which were attached to the Direct Testimony of David E. Hunt, the Company will act as the sole Midcontinent Independent System Operator (“MISO”) Market Participant on behalf of retail customers and Aggregators of Retail Customers (“ARCs”) that have aggregated capable retail customers. In the Company’s monthly settlement statement from MISO, revenues (and any penalties, if applicable) will be split out for any registered Demand Response (“DR”) resources that participate in MISO’s wholesale markets through Schedule MVDR. As far as administrative and related billing costs associated with Schedule MVDR, those costs will be reflected in Federal Energy Regulatory Commission (“FERC”) account 457.1 identical to current treatment of other similar non-fuel operations and maintenance expenses.

b. Yes, per Schedule MVDR, Section IV(A)(1), the retail customer or ARC will receive monthly the applicable MISO settlement amount less 10% (plus any applicable fees or penalties for failure to perform).

c. Per Schedule MVDR, ETI will act as the sole Market Participant in MISO registering and representing any retail customer or ARC that aggregates retail customers with demand response capabilities per the agreed-upon locations and quantities reflected in an executed MVDR Agreement. See also the Direct Testimony of David E. Hunt, pages 25-26.

d. See the Company's response to TIEC 3-11(a).

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Andrew Owens Sponsoring Witness: David E. Hunt Beginning Sequence No. LR886 Ending Sequence No. LR886

Question No.: TIEC 3-12 Part No.: Addendum:

Question:

Would a MVDR participant have the flexibility of periodically adjusting the demand/prices submissions to address changing or exigent circumstances from time-to-time? If not explain why. If so, state the process through which demand/price submissions can be adjusted and what limitations, if any, ETI would impose.

Response:

Yes. See Schedule Market Valued Demand Response ("MVDR") Sections III(D) and IV(D) as well as various provisions within the MVDR Agreement, including Articles II and III.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.	Prepared By: Jess K. Totten, Richard D. Starkweather
to the Third Set of Data Requests	Sponsoring Witnesses: Jess K. Totten, Richard D. Starkweather
of Requesting Party: Texas Industrial Energy Consumers	Beginning Sequence No. LR887
	Ending Sequence No. LR888

Question No.: TIEC 3-13 Part No.: Addendum:

Question:

Referring to pages five to six regarding low rates:

a. Please explain why Mr. Totten believes that the period 2017-2021 is the appropriate reference period for determining whether rates are low for the purpose of an return on equity (ROE) bonus to be granted for rates in place in 2023.

b. Please state whether Mr. Totten or Mr. Starkweather have updated the comparisons to include rates in 2022.

Response:

a. The period in question is appropriate for evaluating Entergy Texas, Inc.'s ("ETI") performance, because it covers a period of several recent years, and they are the most recent years for which information was available for filing with this rate case. Recent performance of ETI's management is more relevant than performance that is remote in time. In addition, ETI's most recent base rate change was approved in the Commission's Final Order issued in Docket No. 48371, dated December 20, 2018. Thus, most of the years in the evaluation were after the last base-rate case, which was a case in which management performance prior to that date would have been relevant to setting a rate of return in that case.

It is not practical to provide an evaluation of a more recent year, as 2022 is not complete. In addition, as Richard D. Starkweather stated in his testimony in the footnote on page 4:

> [Federal Energy Regulatory Commission ("FERC")] Form 1s for the previous calendar year must be filed on or before April 18th of the following year. For example, the FERC Form 1s for 2021 were filed on or before April 18, 2022. Thus, 2021 data was the most recent

FERC Form 1 data available for the purposes of the analysis in Mr. Starkweather's Direct Testimony.

b. Neither Mr. Starkweather nor Jess K. Totten has updated this analysis to include rates in 2022.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Jess K. Totten Sponsoring Witness: Jess K. Totten Beginning Sequence No. LR889 Ending Sequence No. LR889

Question No.: TIEC 3-14 Part No.: Addendum:

Question:

Referring to pages six to seven:

a. Please explain why Mr. Totten believes that the period 2018-2020 is the appropriate reference period for determining whether O&M costs are low for the purpose of an ROE bonus to be granted for rates in place in 2023.

b. Has Mr. Totten or Mr. Sperandeo updated the comparisons to include rates in 2021 or 2022?

c. Are these non-fuel O&M expenses or O&M including fuel?

Response:

a. The period in question (2018-2021) is appropriate for evaluating Entergy Texas, Inc.'s ("ETI") performance, because it covers a period of several recent years, and they are the most recent years for which information was available for filing with this rate case. See also the Company's response to TIEC 3-13.

b. Bobby R. Sperandeo's analysis, as filed in his Direct Testimony, did evaluate ETI's performance in 2021. Neither Mr. Sperandeo nor Jess K. Totten has updated this analysis to include costs in 2022.

c. These are non-fuel O&M expenses.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Jess K. Totten Sponsoring Witness: Jess K. Totten Beginning Sequence No. LR890 Ending Sequence No. LR890

Question No.: TIEC 3-15 Part No.: Addendum:

Question:

Referring to pages eight to 11 regarding ETI' s response to two hurricanes, has Mr. Totten examined any other utilities' responses to hurricanes to determine how ETI' s hurricane response ranked in relation to other utilities' responses? If not, please explain why not and how Mr. Totten determined ETI' s response was effective and efficient. If yes, please provide Mr. Totten' s examination of other utilities' responses.

Response:

Jess K. Totten has not analyzed the response of other utilities to hurricanes. Mr. Totten's conclusion that Entergy Texas, Inc. ("ETI") performed well is based on the testimony from ETI witnesses that he cites in his testimony and his prior experience as a manager at the Public Utility Commission of Texas, where he observed the performance of utilities in responding to the impacts of hurricanes and other weather events.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc.
to the Third Set of Data Requests

of Requesting Party: Texas Industrial Energy Consumers

Prepared By: Charles DeGeorge, Ryan Gay
Sponsoring Witnesses: Anastasia R. Meyer, Beverley Gale
Beginning Sequence No. LR895
Ending Sequence No. LR897

Question No.: TIEC 3-16 Part No.: Addendum:

Question:

For Montgomery County Power Station (MCPS), please provide:

a. By year, the projected capacity factors from ETI' s base case from the MCPS CCN;

b. By year, the projected variable energy cost savings from ETI' s base case from the MCPS CCN;

c. By year, the projected capacity factors from ETI' s base case from the Orange County Advanced Power Station CCN analysis; and

d. By month, the actual capacity factor for MCPS from June 2021 - June 2022.

Response:

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.110. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

a. See the highly sensitive table below for the projected capacity factors for Montgomery County Power Station ("MCPS") from the MCPS Certificate of Convenience and Necessity ("CCN") Docket No. 46416.

	[redacted]		[redacted]		
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	

	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	

b. See the highly sensitive table below for the projected variable supply cost savings for MCPS from the MCPS CCN Docket No. 46416.

	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	

c. See the highly sensitive table below for the projected capacity factors for MCPS from the Orange County Advanced Power Station CCN Docket No. 52487.

	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	

d. See the highly sensitive table below for the actual monthly capacity factors for MCPS for June 2021 through June 2022.

	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	
	[redacted]			[redacted]	

DESIGNATION OF PROTECTED MATERIALS PURSUANT TO PARAGRAPH 4 OF DOCKET NO. 53719 PROTECTIVE ORDER

The Response to this Request for Information includes Protected Materials within the meaning of the Protective Order in force in this Docket. Public Information Act exemptions applicable to this information include Tex. Gov't Code Sections 552.101 and/or 552.110. ETI asserts that this information is exempt from public disclosure under the Public Information Act and subject to treatment as Protected Materials because it concerns competitively sensitive commercial and/or financial information and/or information designated confidential by law.

Counsel for ETI has reviewed this information sufficiently to state in good faith that the information is exempt from public disclosure under the Public Information Act and merits the Protected Materials Designation.

Kristen F. Yates
Entergy Services, LLC.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Russ Cochran Sponsoring Witness: Gary C. Dickens Beginning Sequence No. LR891 Ending Sequence No. LR891

Question No.: TIEC 3-17 Part No.: Addendum:

Question:

How did the two hurricanes that hit during the summer of 2021 affect the construction of MCPS?

Response:

While it is unclear which 2021 hurricanes are being referred to in the question, the Montgomery County Power Station ("MCPS") was substantially complete and placed in service on January 1, 2021. During the mid to late 2020 hurricane season, transmission upgrades associated with the MCPS project were delayed approximately 5-7 weeks due to the effects of hurricanes Laura and Delta. However, the Company was successful in bringing the project to a close ahead of the original project schedule.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Hunter Leland Sponsoring Witness: N/A Beginning Sequence No. LR892 Ending Sequence No. LR892

Question No.: TIEC 3-18 Part No.: Addendum:

Question:

How many miles is the MCPS from the landfall location of each of the two storms?

Response:

Hurricane Laura made landfall approximately 140 miles from Montgomery County Power Station ("MCPS") based on landfall information contained in the following report from the National Hurricane Center
https://www.nhc.noaa.gov/data/tcr/AL132020_Laura.pdf.

Hurricane Delta made landfall approximately 150 miles from MCPS based on landfall information contained in the following report from the National Hurricane Center
https://www.nhc.noaa.gov/data/tcr/AL262020_Delta.pdf.

Please refer to the Company's response to TIEC 3-17 for information regarding how the storms affected the construction of MCPS.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Jess K. Totten Sponsoring Witness: Jess K. Totten Beginning Sequence No. LR893 Ending Sequence No. LR893

Question No.: TIEC 3-19 Part No.: Addendum:

Question:

Did Mr. Totten consider the Commission's rejection of ETI' s CCN for the Liberty County Solar facility in his consideration of whether ETI's management was effective and efficient? If not, please explain why not. If yes, please explain in detail how Mr. Totten included that rejection in his consideration.

Response:

No. The outcome of regulatory proceedings was not in the scope of Jess K. Totten's analysis.

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

Response of: Entergy Texas, Inc. to the Third Set of Data Requests of Requesting Party: Texas Industrial Energy Consumers	Prepared By: Jess K. Totten Sponsoring Witness: Jess K. Totten Beginning Sequence No. PI1664 Ending Sequence No. PI1956

Question No.: TIEC 3-20 Part No.: Addendum:

Question:

Referring to page three, please provide any analyses of ETI' s performance in response to significant storms in the last four years.

Response:

Entergy Texas, Inc. ("ETI") provided testimony concerning its performance in the 2020 hurricanes in this case and in its initial filing in *Application of Entergy Texas, Inc. for Determination of System Recovery Costs*, Docket No. 51997, which is available on the Commission Interchange. In particular, see the attachments (TP-53719-00TIE003-X020-001 and TP-53719-00TIE003-X020-002) for the Direct Testimonies of Allen East, describing the restoration of the distribution system following Hurricanes Laura and Delta; and Charles, W. Long, describing the restoration of the transmission system following Hurricanes Laura and Delta. ETI is not aware of any other analyses of its storm restoration performance.

DOCKET NO. 51997

APPLICATION OF ENTERGY	§	BEFORE THE
TEXAS, INC. FOR DETERMINATION	§	PUBLIC UTILITY COMMISSION
OF SYSTEM RESTORATION COSTS	§	OF TEXAS

DIRECT TESTIMONY

OF

ALLEN EAST

ON BEHALF OF

ENTERGY TEXAS, INC.

APRIL 2021

DOCKET NO. 51997

APPLICATION OF ENTERGY TEXAS, INC. FOR DETERMINATION OF SYSTEM RESTORATION COSTS

DIRECT TESTIMONY OF ALLEN EAST

TABLE OF CONTENTS

EXHIBITS

Exhibit ATE-1	Illustrative Photos of Hurricane Laura Damage to Distribution Facilities
Exhibit ATE-2	Illustrative Photos of Hurricane Delta Damage to Distribution Facilities
Exhibit ATE-3	Description of Restoration Tasks – Distribution
Exhibit ATE-4	Major Distribution Restoration Activities with Work Descriptions and Photos
Exhibit ATE-5	Distribution Contractor List
Exhibit ATE-6	SEE Mutual-Assistance Agreement
Exhibit ATE-7	EEI Mutual-Assistance Agreement

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Allen East. I am Vice President, Distribution Operations for Entergy Texas, Inc. ("ETI" or the "Company"). My business address is 10055 Grogans Mill Rd., The Woodlands Texas, 77380.

Q2. ON BEHALF OF WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of ETI.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science degree in Electrical Engineering from Mississippi State University. In 1986, I went to work for Mississippi Power and Light Company (presently referred to as Entergy Mississippi LLC ("EML")) as a Distribution Engineer in Rankin County, Mississippi. I left Entergy in 1994 and became co-owner of B&B Utility, Inc. (Distribution Line Contractor). I returned to EML in 1997 and served as the Manager of Construction. After a year, I was transferred to Manager of the Distribution Operations Center. A year later, I was transferred to Network Manager over the Clinton, Mississippi service area. Then from 2000-2008, I served as the Operations Manager for EML with responsibility for the Construction of Large Projects, Work Management, Reliability, Meter Services, Street Lights, Distribution Operations Centers, and Storm Management. In this role, I served as the EML Storm Manager during the restoration efforts for

Hurricane Katrina. I relocated to Entergy Arkansas LLC ("EAL") in 2008 and served as the Central Region Manager until 2012 when I was transferred to the transmission organization as the Grid Manager for EML. In 2014, I relocated to ETI as the West Region manager based in The Woodlands, Texas. I was promoted in 2019 to Vice President, Distribution Operations for ETI and continue to serve in that role today.

Q4. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. My responsibilities include all aspects of engineering and operations for ETI's electric distribution system, including but not limited to safety, operations, construction, reliability improvement, engineering, and contract management. I also have oversight of asset planning, distribution dispatching, meter services, and metering.

II. PURPOSE AND SUMMARY OF TESTIMONY

A. Purpose of Testimony

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I support the recovery of ETI's reasonable and necessary system restoration costs ("SRCs") related to Hurricanes Laura and Delta for the Distribution Class of costs. My testimony covers five main topics. First, I discuss the impacts of Hurricanes Laura and Delta on ETI's distribution system in August and October 2020, respectively. Then I discuss our distribution restoration plans and the significant efforts to implement the plans for those hurricanes. Next, I discuss the resources utilized and the costs associated with the Distribution Class of SRCs incurred as a result of the hurricanes. I address the affiliate charges incurred by ETI in its Hurricane Laura and Delta system restoration efforts. Finally, I discuss and present certain distribution-related SRCs that the Company seeks to have determined in this docket incurred as a result of Winter Storm Uri in February 2021.

Q6. WHY ARE YOU QUALIFIED TO ADDRESS THESE ISSUES AND TO PROVIDE THIS TESTIMONY?

A. In my role as Director of Distribution Operations for ETI, I am responsible for and oversee on a daily basis most of the activities addressed in my testimony. The affiliate activities addressed in my testimony were in support of the Distribution Operations organization that I oversee. The Distribution Class includes the general facilities and general plant that Distribution Operations uses on a daily basis and during major storm events. These facilities are owned/leased and operated by ETI, under the Distribution Operations umbrella.

Q7. DO YOU SPONSOR ANY EXHIBITS?

A. Yes. The exhibits that I sponsor are listed in the table of contents to this testimony.

B. Summary of Restoration Costs

Q8. ARE THE MAJORITY OF THE COSTS YOU SPONSOR RELATED TO DAMAGES CAUSED BY HURRICANES LAURA AND DELTA?

A. Yes. The majority of the SRCs that I include and sponsor were incurred as a result of Hurricanes Laura and Delta, which made landfall in August and October 2020, respectively. I also sponsor and include SRCs incurred as a result of Winter Storm Uri in February 2021.

Q9. WHAT WERE THE SYSTEM RESTORATION COSTS INCURRED BY ETI AS A RESULT OF HURRICANES LAURA AND DELTA AND WINTER STORM URI?

A. The combined SRCs for Hurricanes Laura and Delta and Winter Storm Uri presented in my testimony are summarized in Table 1 below. This includes both costs that have been booked as of February 28, 2021 and additional estimated costs.

Table 1
Distribution Class System Restoration Costs

Distribution Class	Hurricane Laura	Hurricane Delta	Winter Storm Uri	Total
Major Resource Category				
Contract Work	$140,295,996	$27,127,226	$296,410	$167,719,672
Labor	$3,908,306	$1,836,461	$1,338,581	$7,083,348
Employee Expenses	$7,012,297	$1,292,261	$5,384	$8,309,942
Materials	$11,380,908	$3,379,143	$1,698,725	$16,458,776
Other	$2,889,179	$511,416	$816,946	$4,217,541
Total Direct Costs	**$165,486,686**	**$34,146,547**	**$4,156,046**	**$203,789,279**
ETI Affiliate Costs				
ESL Billings	$2,506,185	$439,723	$196,193	$3,142,101
Loaned Resources	$1,474,179	$435,125	$6,953	$1,916,257
Total Affiliate Costs	**$3,980,364**	**$874,848**	**$203,146**	**$5,058,358**
Total Booked Costs	**$169,467,050**	**$35,021,395**	**$4,359,192**	**$208,847,637**
ETI Estimated Costs	$12,544,739	$1,642,725	--	**$14,187,464**
Total Distribution Class Costs	**$182,011,789**	**$36,664,120**	**$4,359,192**	**$223,035,101**

C. Summary of Restoration Efforts and Resources

Q10. PLEASE BRIEFLY DESCRIBE HURRICANES LAURA AND DELTA.

A. Hurricane Laura was a Category 4 hurricane that made landfall near peak intensity on August 27, 2020 at Cameron, Louisiana. It is the strongest hurricane on record to make landfall in Louisiana and caused massive damage across southwestern Louisiana and southeastern Texas.

Six weeks after Hurricane Laura, Hurricane Delta made landfall on October 9, 2020 as a Category 2 hurricane near Creole, Louisiana (just 12 miles east of Cameron, Louisiana), also causing significant damage across southwestern Louisiana and southeastern Texas.

Q11. PLEASE SUMMARIZE THE STATISTICS CONCERNING THE PERSONNEL UTILIZED BY ETI IN RESTORING ITS DISTRIBUTION FACILITIES FOLLOWING BOTH HURRICANE LAURA AND HURRICANE DELTA.

A. As detailed in section IV.C.1 below, ETI utilized over 6,300 personnel to restore the distribution system after Hurricane Laura, and ETI utilized over 1,800 personnel to restore the distribution system after Hurricane Delta.

Q12. WHAT WERE THE PRIMARY COST DRIVERS THAT AFFECTED THE HURRICANE LAURA AND DELTA SYSTEM RESTORATION COSTS INCURRED BY ETI?

A. There were three primary cost drivers that affected the restoration efforts: (1) the intensity of the hurricanes and the widespread damage sustained; (2) certain obstacles to restoration; and (3) the urgency of ETI's response. I summarize here the manner in which those cost drivers affected the SRCs that I sponsor.

The Intensity of the Hurricanes and the Damage Sustained: Hurricanes Laura and Delta occurred mere weeks apart taking similar paths through ETI's service territory. Hurricane Laura was a destructive Category 4 hurricane with intense winds followed shortly thereafter by Hurricane Delta, a Category 2 hurricane causing additional damage in some of the same areas. Together, these storms severely damaged ETI's distribution infrastructure, including over 2,400 poles, 1,590 transformers, and 2,000 spans of conductor. The magnitude of the storms required ETI to utilize a large amount of resources to restore service in a timely manner.

Obstacles to Restoration: During the active hurricane season of 2020, the frequency and severity of storms across the region and ETI's service territory meant that demand was high for certain limited resources. The demands for mutual-aid utility resources and third-party contractors were very high due to concurrent restorations and the needs of other Gulf Coast utilities preparing for and responding to these two hurricanes, as well as other hurricanes that occurred during the very busy 2020 hurricane season. The high demand for available resources required us to acquire help from ten different states – Texas, Florida, Alabama, Virginia, North Carolina, Tennessee, Missouri, Kansas, Oklahoma, and Georgia.

Following each storm, many roads were closed or impassable due to high water or debris. As with any major hurricane, large amounts of scattered debris, either natural (primarily vegetation) or manmade, were present. The dense vegetation in ETI's service territory contributed to the significant damage incurred and also created significant obstacles to access damaged distribution facilities. Additionally, the topology of ETI's distribution system, which includes a large percentage of rear-lot and alley construction that requires special equipment to access, further complicated the restoration process. Communications were also impacted due to landline, radio, and cell tower damage, which presented yet another obstacle to system restoration.

Additionally, as discussed below, ETI conducted these hurricane restorations while having to address the challenges posed by conducting restoration efforts amidst the COVID-19 pandemic and protocols related thereto.

The Urgency of ETI's Response: The Company understands the importance of quickly and safely restoring service to protect the health and safety of its customers, including essential state and local emergency facilities. It is also critical to restore service to key facilities that have a significant impact on the regional and national economy. ETI was aware before the hurricanes made landfall that rapid restoration of service would be required. For each storm, ETI pre-staged as many materials and workers as possible, and restoration began as soon as it was safe to proceed. To restore service as quickly as possible, ETI used every available resource to the maximum extent, which included long hours by every worker and expedited delivery of materials from every source reasonably available. Had ETI not gone to these lengths, restoration of service would have taken significantly longer. Through these efforts, ETI was able to restore service to the customers who were able to accept service by September 6, 2020 following Hurricane Laura (which was only 10 days after it made landfall) and by October 15, 2020 following Hurricane Delta (which was only 6 days after it made landfall).

Q13. ARE THE COSTS THAT YOU SUPPORT HIGHER THAN THEY WOULD HAVE BEEN RELATIVE TO CONDITIONS WHEN THERE IS NOT A MAJOR STORM?

A. Yes. Due to the magnitude of damage from the storms, as I will describe later, the fact that time was of the essence, the emergency circumstances that existed at the time, and the impact of the COVID-19 pandemic and managing those safety protocols, the overall costs are higher than they would have been under normal circumstances, especially considering that other areas in the region were also recovering from Hurricanes Laura and Delta as well as several other hurricanes that made landfall in the Texas and Louisiana coastal areas during the June-November 2020 period. Thus, as a practical matter, the Entergy System and its storm-preparation functions were on high alert for the entire period of time. Moreover, as noted above, the frequency and severity of storms across the region over that period created significant challenges for ETI and the Entergy System in planning and procuring the necessary resources in terms of personnel (*e.g.*, mutual-aid assistance, third-party contractors, and the sharing of resources among the Entergy Operating Companies), logistics, equipment, and materials. Obviously, the demand for those resources was high across the region and the supply stretched thin. The COVID-19 pandemic also impacted many manufacturing and supply lines. Nonetheless, ETI was diligent in planning and preparing for Hurricanes Laura and Delta, and we were able to overcome those challenges and conduct a thorough and efficient restoration following both hurricanes at a reasonable cost and without incurring significant premiums or scarcity pricing.

Q14. PLEASE EXPLAIN THE CIRCUMSTANCES THAT CAUSED COSTS TO BE HIGHER RELATIVE TO CONDITIONS WHEN THERE IS NOT A MAJOR STORM.

A. There are three main circumstances that increased costs during the restorations following Hurricanes Laura and Delta: (1) the need/requirement to restore service as quickly and safely as possible; (2) the demand for limited personnel, material and logistical resources required for such widespread damage; and (3) safety and health protocols associated with the COVID-19 pandemic. Hurricanes Laura and Delta not only impacted ETI, but they also caused significant damage to areas served by ETI's sister company, Entergy Louisiana, LLC ("ELL"). Hurricanes Laura and Delta both came ashore in the Lake Charles, Louisiana area and caused significant damage to ETI's Silsbee, Beaumont, Orange, and Port Arthur service territories. There was also scattered damage in the Dayton and Winnie service territories and as far west as ETI's Conroe, New Caney, and Cleveland service territories.

Had we used only Entergy personnel and our contractors who are contractually committed to provide resources, service restoration would have taken months longer. Even with the engagement of our mutual-aid utility partners and our normal emergency line/vegetation contractors, it still would have taken weeks to reconstruct our electric facilities because of the significant damage. As I will explain later, some resources, such as line, vegetation, materials, and logistics support, were not available in close proximity due to the concurrent need for those resources by ELL, and due to the fact that Hurricanes Laura and Delta occurred in proximate time and location. So for timely restoration, we also had to engage additional line contractors and vendors who were not part of our normal daily operations.

Q15. HOW DID THE NEED TO QUICKLY RESTORE SERVICE AFFECT COSTS?

A. ETI incurred additional or incremental costs that would not have existed absent the need to restore service quickly and concurrently to a significant number of customers. These additional or incremental costs include items such as:

- **Additional Crews** – For the Hurricane Laura restoration, ETI brought in over 6,000 personnel from mutual-aid utilities and third-party contractors to assist in the distribution service restoration. For the Hurricane Delta restoration, ETI brought in over 1,600 personnel from mutual-aid utilities and third-party contractors to assist in the distribution service restoration. Given the damage to vegetation and the Company's transmission and distribution facilities, ETI had to significantly supplement its existing workforce to clear debris, access damaged facilities, and repair those facilities so that service could be restored. Due to the continuing demand for those types of contractors by other utilities, ETI had to draw on mutual-aid and contractor resources from more distant locations than it had in the past.
- **Overtime/Premium Pay** – Instead of working typical 40-hour weekly work shifts, employees and contractors worked up to 112-hour weekly work shifts to restore service as quickly and safely as possible. ETI was therefore required to pay overtime labor rates to these workers. A 112-hour work week is a 180% increase over a normal 40-hour work week. In addition, some of the contractors we engaged require a single premium rate for storm restoration that is applied to all hours. This practice is becoming more

common for storm response crews, and it is generally one and one-half to two times the normal straight-time rate.

- **Lodging** – When personnel and crews are brought into the Company's service territory, the cost of this temporary work force includes not only labor costs, but also the expense of housing, feeding, and other related costs to support the crews. The total workforce for the distribution restoration was over 6,300 workers and support personnel. Hotel rooms were in short supply due to power outages and damages to the hotels and other lodging facilities caused by Hurricanes Laura and Delta. The Company was also competing for rooms with hurricane evacuees from the surrounding areas, as well as essential workers from local industries.
  - **Hurricane Laura** – For at least two hotels, the Company, in exchange for rooms, provided and installed generators to provide power to the hotels. The primary resource for lodging was hotels, but there was still a gap between the number of hotel rooms and number of resources involved. For Hurricane Laura, to fill this gap, the Company engaged some lodging specialists, who set up sites with bunk trailers to house and feed approximately 2,000 workers. These sites entail a premium cost, but it enabled the Company to lodge restoration personnel in the affected area and bridged the gap left by the shortage of available hotel rooms. Another major consideration was the fact that the country was in the middle of the COVID-19 outbreak. Additional safety protocols had to be enacted

to mitigate the spread of the virus among workers. The protocols limited lodging to one person per room in hotels and mandated spatial requirements for crews sleeping in bunk trailers. Extra cleaning and disinfecting procedures were implemented for rooms, showers, and meeting areas, and routine sanitization was performed for all areas.

  - **Hurricane Delta** – The primary resource for lodging was hotels, but the turnkey lodging vendors were still engaged at the outset.

- **Food** – In addition to lodging, all of the restoration personnel had to be fed. ETI fed over 6,300 distribution restoration workers three times a day throughout the restoration period. Local restaurants were simply not available. COVID-19 protocols were also set up and enforced for food service. Spatial requirements had to be met and food only served by workers behind plexiglass shields.

  - **Hurricane Laura** – To feed the workers, the Company set up catering sites in strategic areas. To feed the workers in the large sleeping sites, the Company contracted with those lodging vendors to also feed the workers at each site. In addition, the Company contracted with three other outside vendors and one local vendor to provide food to workers.
  - **Hurricane Delta** – As needed, the same vendors that supported the Hurricane Laura restoration were originally engaged in supporting the Hurricane Delta restoration. When power began to return, the

lodging vendors were released, and later the catering vendors were released and replaced with a local vendor.

- **Increased Materials Prices** – Due to Hurricanes Laura and Delta making landfall in a relatively short period of time along the Texas and Louisiana coasts and the effect of material vendors being limited due to COVID-19, some essential materials were in high demand. As the demand became greater for the materials, ETI had no choice but to engage supply vendors that it had not normally used. In some cases, the Company paid premium rates for essential materials.

Q16. WOULD SERVICE RESTORATION HAVE TAKEN SIGNIFICANTLY LONGER HAD THE COMPANY NOT INCURRED THESE COSTS?

A. Certainly. If ETI had utilized only its existing crews, restoration for both Hurricane Laura and Hurricane Delta would have taken months longer than it did. This length of time would not have been acceptable. Even if ETI had utilized the outside contractor resources that it did, but without working any overtime hours, the restoration of the distribution system would have taken at least five weeks longer than it did for each storm. In fact, many of those contractors would not have been willing to provide their crews had ETI not committed to utilize them on an overtime basis. Also, with the additional costs of the COVID-19 safety protocols, there was the potential to spread the virus. This would not only pose a health risk to the communities in which we were working, but it would also threaten the health of line workers and risk the potential loss of dozens of crews to quarantine. The Company therefore took the steps necessary for a fast and safe restoration.

Q17. YOU MENTIONED ABOVE THAT THE 2020 HURRICANE SEASON WAS UNUSUALLY ACTIVE IN THE ATLANTIC BASIN AND ALONG THE GULF COAST SERVICE TERRITORIES OF THE ENTERGY OPERATING COMPANIES. PLEASE EXPLAIN.

A. The 2020 hurricane season was extremely active by any measure. According to the National Oceanic and Atmospheric Administration ("NOAA"), the 2020 Atlantic Hurricane Season produced a record number of 30 named storms, of which 13 became hurricanes (winds of 74 mph or greater), including 6 major hurricanes (winds of 111 mph or greater). A total of 12 storms made landfall in the continental U.S., with 5 storms making landfall in Louisiana and 3 making landfall in Texas. That is the highest number of named storms on record, surpassing the 28 named storms that occurred in 2005, and it is the second highest number of hurricanes on record. Those numbers exceeded NOAA's May and August 2020 forecasts. The updated August 2020 NOAA forecast called for 24 named storms, 12 hurricanes, and 5 major hurricanes. On average, 10.1 named storms occur each season, with an average of 5.9 becoming hurricanes and 2.5 becoming major hurricanes (Category 3 or greater). In addition to Hurricanes Laura and Delta, the Entergy System had to prepare for and manage the following named storms:

- Cristobal
- Marco
- Sally

- Beta
- Zeta

Q18. WHY DID THE COMPANY HAVE DIFFICULTY OBTAINING CERTAIN MATERIALS AND OTHER RESOURCES DURING THE HURRICANE LAURA AND HURRICANE DELTA RESTORATIONS?

A. The materials and resources that would normally have been stockpiled and available were limited, primarily as a result of Hurricane Laura, but also due to the overall effect of the record 2020 hurricane season and COVID-19 pandemic effects on the suppliers and capacity of manufacturers. ETI leveraged existing supplier agreements when possible but had to turn to alternate suppliers in order to obtain some essential supplies. These supplies were generally more expensive than those acquired from ETI's pre-arranged vendors and included costs to expedite their production and delivery. A number of unique factors caused some of the price increases. Catastrophic damage to ETI and neighboring utility infrastructure exponentially increased demand for the material used for storm restoration efforts. Fuel supplies were impacted by the storms in the Gulf region, immediately affecting fuel costs and delivery charges. With Hurricanes Laura and Delta impacting not only ETI but other utilities in Texas, material costs were also affected by the basic principle of supply and demand. Demand for materials had already been stressed due to damage incurred from earlier storms. The widespread damage from Hurricanes Laura and Delta and material requirements for restoration at a time when there was an already-stressed market only exacerbated the situation.

Q19. DOES ETI MAINTAIN DISTRIBUTION MATERIAL INVENTORIES SUFFICIENT TO ADDRESS DAMAGE RESULTING FROM A STORM THE MAGNITUDE OF HURRICANE LAURA OR HURRICANE DELTA?

A. No. Our material inventories are generally sufficient to enable us to address normal construction and routine storm damage without calling for additional resources from alternate vendors. It would not be practical or cost-effective for ETI to maintain inventories of distribution-related materials large enough to address the extent of damage caused by Hurricane Laura (*e.g.*, over 1,800 poles) or Hurricane Delta (*e.g.*, over 600 additional poles). Furthermore, Entergy's system-wide centralized supplies of storm kits, prepared materials, and supplies from company stores and inventory were reduced while responding initially to Hurricane Laura in Louisiana and Texas. As a practical matter, however, ETI's normal inventory of distribution materials, together with the supply that might have been available from Entergy's centralized supply, would have provided only a small percentage of the supplies necessary to reconstruct the distribution system after Hurricane Laura and Delta (*e.g.*, over 1,590 transformers, 3,950 switches, 2,400 poles). We would have to rely upon vendors to provide the great majority of our distribution material needs in any event. Entergy generally has pre-negotiated arrangements with vendors to supply the types and amounts of materials needed. Accordingly, in preparation for Hurricane Laura's landfall, materials and stores personnel began the difficult task of procuring mass amounts of materials such as poles, cross-arms, transformers, and wire from key and alternate vendors as well as other utilities throughout the country. It should be further noted that the pandemic impacted the amount of