Entergy

Entergy Services, LLC
639 Loyola Avenue 70113-3125
P.O Box 61000
New Orleans, LA 70161-1000
Tel 504 576 2984
Fax 504 576 5579

Harry M. Barton
Senior Counsel
Legal Services - Regulatory

May 13, 2019

Via Hand Delivery
Lora W. Johnson, CMC, LMMC
Clerk of Council
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

Re: Investigation of the Potential Costs and Benefits of Entergy New Orleans, Inc. and Entergy Louisiana, LLC Joining a Regional Transmission Organization Versus Continuation of the Entergy Independent Coordinator of Transmission with Enhancements (CNO Docket No. UD-11-01)

Dear Ms. Johnson:

Please find enclosed an original and three copies of the Public Version of Entergy New Orleans, LLC's ("ENO") Fifth Annual Post-MISO-Integration Monitoring Report to be filed in the above-referenced docket. Please file an original and two copies into the record in the above referenced matter, and return a date-stamped copy to our courier.

In connection with ENO's filing, a Confidential Version of the above-described documents bearing the designation "Highly Sensitive Protected Materials" are being provided to the appropriate Reviewing Representatives pursuant to the terms and conditions of the Official Protective Order adopted in Council Resolution R-07-432. Portions of the information included in the filing consist of highly sensitive information, the disclosure of which may subject not only the Company, but also its customers, to a substantial risk of harm. As such, these confidential materials shall be exempt from public disclosure, subject to the provisions of Council Resolution R-07-432.

Thank you for your assistance with this matter.

Sincerely,

Harry M. Barton

RECEIVED
MAY 13 2019
BY:

HMB/bkd

Enclosures
cc: Official Service List UD-11-01 *(via Electronic mail)*

Rec'd 3 08

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

INVESTIGATION OF THE POTENTIAL COSTS AND BENEFITS OF ENTERGY NEW ORLEANS, INC. AND ENTERGY LOUISIANA, LLC JOINING A REGIONAL TRANSMISSION ORGANIZATION VERSUS CONTINUATION OF THE ENTERGY INDEPENDENT COORDINATOR OF TRANSMISSION WITH ENHANCEMENTS	)))))))))	**DOCKET NO. UD-11-01**

ENTERGY NEW ORLEANS, LLC'S FIFTH ANNUAL POST-MISO-INTEGRATION MONITORING REPORT

Pursuant to, and in compliance with, Council of the City of New Orleans ("Council") Resolution R-15-139, dated April 9, 2015, Entergy New Orleans, LLC ("ENO" or the "Company")[1], submits its Fifth Annual Post-MISO-Integration Monitoring Report ("Report") related to the integration of ENO into the Midcontinent Independent System Operator, Inc. ("MISO") regional transmission organization ("RTO") on December 19, 2013. The headings and sub-headings set forth below correspond to the headings and sub-headings contained in the Summary of Proposed Post-MISO-Integration Reporting Guidelines, in Exhibit 4 to the Agreement in Principle attached to Council Resolution R-15-139. On December 14, 2017, the Council adopted Resolution R-17-627 in Docket No. UD-17-02, that found, among other things, that ENO's continued membership in MISO beyond December 19, 2018, is in the public interest at this time. This Fifth Annual Report includes estimated benefits to ENO customers resulting from the Company's continued membership in MISO calculated as of the end of 2017 and 2018.

[1] Effective December 1, 2017, Entergy New Orleans, Inc. underwent a Council-approved corporate restructuring to become a limited liability company. Accordingly, the utility formerly operating as Entergy New Orleans, Inc. is now operating as Entergy New Orleans, LLC.

a. Resource Adequacy

1. The following related to resource adequacy in MISO for ENO[2] for the current Planning Year including:

i. The Results from MISO's Planning Resource Auction for the current Planning Year

MISO's Resource Adequacy Construct, including the Planning Resource Auction ("PRA"), is conducted on an annual basis coinciding with the MISO Planning Year, which begins on June 1 of a given year and concludes on May 31 of the following year. The Resource Adequacy Construct establishes capacity requirements for specific geographic areas, known as Local Resource Zones ("LRZs"), which can be met through participation in the PRA. ENO is located in LRZ 9, which covers Louisiana and Texas. ENO owns, and has long-term contracts with, generating resources located in LRZ 8 (Arkansas) and LRZ 10 (Mississippi). The PRA results in a clearing price for each LRZ, which is used for both capacity purchases and capacity sales for auction participants within each LRZ. The 2018-2019 PRA resulted in a clearing price of $10.00/MW-day for all MISO LRZs except for LRZ 1, which cleared at $1.00/MW-day.[3]

ii. A list of the capacity purchases, by amount and cost, made by ENO

Certain information responsive to this component of the filing has been designated as Highly Sensitive Protected Material ("HSPM"), has been redacted from the Public Version of this

[2] Resolution 15-139 contemplated the "System Agreement Operating Companies," which included ENO and the other Entergy operating companies (ELL, ETI, EMI, and EAI). Because the Entergy System Agreement terminated on August 31, 2016, the information and data in this and each subsequent Report shall only be provided for ENO.

[3] ENO notes that the 2018-19 PRA resulted in a clearing price of $10/MW-day, an increase from $1.50 per MW-day the prior year for LRZ 9.

filing, and will be provided only to Reviewing Representatives authorized and designated under the confidentiality agreement executed in this docket.

ENO has been participating in MISO's Resource Adequacy market for the 2018-2019 Planning Year since June 1, 2018. From June 1, 2018 through May 31, 2019, ENO [redacted] reflecting the auction clearing price of $10.00/MW-day and Zonal Deliverability Benefits of $0.04/MW-Day.

Please see HSPM Attachment 1 titled [redacted] for more detailed information regarding ENO's participation in the 2018-2019 PRA.

b. Market Operations

1. **A breakdown of the energy mix used to supply ENO's customers, for the previous twelve month period, showing the MWh and average cost by month, as supplied by resources owned or controlled (through limited or long-term bilateral purchase power agreements) by ENO, and purchases from the MISO markets**

Please see HSPM Attachment 2 titled [redacted] for a breakdown of the energy mix used to serve ENO's customers in 2018.

2. **The following related to congestion hedging for the System Agreement Operating Companies, collectively and individually:**

   i. **The allocation of Auction Revenue Rights ("ARRs") and Financial Transmission Rights ("FTRs") received by ENO**

Please see HSPM Attachment 3, titled [redacted] which outlines the allocation of ARRs and FTRs to ENO for the 2018-19 Planning Year.

   ii. **The cost of any ARRs and FTRs purchased by ENO in the MISO market processes**

The information responsive to this component of this filing has been designated as HSPM.

[redacted]

[redacted]

iii. The annual net congestion charges (net of congestion revenues which will be identified and quantified separately), if any, paid by ENO to MISO

The Company's net congestion charges are shown in the table below, with positive numbers reflecting net congestion charges and negative numbers reflecting net congestion revenues. Congestion charges represent the cost of delivering owned and contracted generation to load. This can be calculated by subtracting the Marginal Congestion Component ("MCC") of the Locational Marginal Price ("LMP") of the generator source from the MCC of the LMP of the load sink.

The HSPM table below reflects congestion charges (net of revenues from ARRs and FTRs) from resources owned or under contract by ENO prior to MISO integration on December 19, 2013 ("pre-MISO integration resources").[4] After the termination of the Entergy System Agreement on August 31, 2016, ENO has modified its net congestion calculation. While the System Agreement was in effect, ENO was allocated a share of the total net congestion incurred by the System Agreement Operating Companies. This calculation included both Day-Ahead and Real-Time market effects, with the specifics of the calculation dictated by the System Agreement for purposes of allocating costs among the System Agreement Operating Companies. As a result of ENO operating as a standalone entity outside of the System Agreement, ENO is able to produce a simplified congestion calculation that only includes Day-Ahead market effects. ENO has chosen to exclude the Real-Time market effects because: (1) FTRs hedge congestion incurred in the Day-Ahead market only and (2) over 97% of ENO's load needs have been served through the Day-

[4] The pre-MISO integration resources include Ninemile Unit 6 because that resource was granted transmission service by the Independent Coordinator of Transmission prior to MISO integration.

Ahead market since joining MISO. The following table reflects ENO's net congestion charges from its pre-MISO integration resources utilizing the Day-Ahead only methodology.

ENO's Net Congestion from Pre-MISO Integration Resources	
Period	**Net Congestion Charge/(Revenue)**
Jan. 1, 2018 – Dec. 31, 2018	[redacted]

3. Net Revenue Sufficiency Guarantee charges (net of any make whole payment revenues, which will be identified and quantified separately), if any, paid by ENO to MISO

The HSPM table below provides a summary of ENO's Revenue Sufficiency Guarantee ("RSG") charges and Make Whole Payments for the period from January 1, 2018 through December 31, 2018. Positive numbers reflect amounts paid to MISO, and negative numbers reflect amounts received from MISO.

Charge/Determinant Name	Description	Charge/(Credit) to ENO (1/1/2018 – 12/31/2018)
Day-Ahead RSG Distribution (DA_RSG_DIST)	The total Day-Ahead RSG Distribution amount obligation for an Asset Owner	[redacted]
Day-Ahead RSG Make Whole Payment (DA_RSG_MWP)	The total Day-Ahead Revenue Sufficiency Make Whole Payment credit for all assets of an Asset Owner	[redacted]
Real-Time First Pass RSG Distribution (RT_RSG_DIST1)	The charges related to funding first pass distribution of Real-Time RSGs	[redacted]
Real-Time Second Pass RSG Distribution (RT_RSG_DIST2)	The charges related to funding second pass distribution of Real-Time RSGs	[redacted]
Real-Time RSG Make Whole Payment (RT_RSG_MWP)	The total credits received for Real-Time RSG Make Whole Payments	[redacted]
Grand Total		[redacted]

4. A summary of the types of ancillary services purchased by ENO from MISO as well as those provided by ENO to MISO and the compensation received by ENO from such services

The HSPM table below provides a summary of ENO's charges and revenues related to MISO ancillary services from January 1, 2018 through December 31, 2018, with positive numbers reflecting amounts paid to MISO and negative numbers reflecting amounts received from MISO.

Charge /Determinant Name	Description	Charge/(Credit) to ENO (1/1/18-12/31/18)
Day-Ahead Regulation (DA_ASM_REG)	The total daily amount due to Asset Owners that own the Regulation Qualified Resources with Day-Ahead Schedules for Regulating Reserves.	[redacted]
Day-Ahead Spinning Reserves (DA_ASM_SPIN)	The total daily amount due to Asset Owners that own the Spin Qualified Resources with Day-Ahead Schedules for Spinning Reserves.	[redacted]
Day-Ahead Supplemental Reserves (DA_ASM_SUPP)	The total daily amount due to Asset Owners that own the Supplemental Qualified Resources with Day-Ahead Schedules for Supplemental Reserves.	[redacted]
Day-Ahead Ramp Capability Amount (DA_RC_AMT)	The total daily amount due to Asset Owners for Up Ramp Capability and/or Down Ramp Capability in the Day-Ahead Energy and Operating Reserve Market.	[redacted]
Contingency Reserve Deployment Failure Charge (RT_ASM_CRDFC)	The total daily net charge for an Asset Owner that owns Resources that was unable to deploy the specified amount of Contingency Reserve within the Contingency Reserve Deployment Period following a Contingency Reserve Deployment Instruction.	[redacted]
Excessive/Deficient Energy Deployment Charge (RT_ASM_EXE_DFE_DEP)	The total daily Asset Owner charge associated with the Asset Owners that was unable to follow Setpoint Instructions and are assessed a share of the cost of procuring regulation service.	[redacted]
Real-Time Net Regulation Adjustment Amount (RT_ASM_NRGA)	Charges or credits to a Resource providing deployed Regulation Service such that the Resource is indifferent to deploying Energy above or below its Dispatch Target for Energy to provide the Regulation Service.	[redacted]
Real-Time Regulation (RT_ASM_REG)	The total daily net charge or credit for an Asset Owner that owns Regulation Qualified Resources with cleared hourly Real-Time Regulating Reserve delta MW.	[redacted]
		[redacted]

Real-Time Regulation Cost Distribution (RT_ASM_REG_DIST)	The total daily charges or credits to an Asset Owner for Day-Ahead and Real-Time Regulating Reserve procurement costs.	
Real-Time Spinning Reserves (RT_ASM_SPIN)	The total daily net charge or credit for an Asset Owner that owns Spin Qualified Resources with cleared hourly Real-Time Spinning Reserve delta MW.	[redacted]
Real-Time Spinning Reserve Cost Distribution (RT_ASM_SPIN_DIST)	The total daily charges or credits to an Asset Owner for Day-Ahead and net Real-Time Spinning Reserve procurement costs.	[redacted]
Real-Time Supplemental Reserves (RT_ASM_SUPP)	The total daily net charge or credit for an Asset Owner that owns Supplemental Qualified Resources with cleared hourly Real-Time Supplemental Reserve delta MW.	[redacted]
Real-Time Supplemental Reserve Cost Distribution (RT_ASM_SUPP_DIST)	The total daily charges or credits to an Asset Owner for Day-Ahead and net Real-Time Supplemental Reserve procurement costs.	[redacted]
Real-Time Ramp Capability Amount (RT_RC_AMT)	The total daily charges or credits to an Asset Owners for Ramp Capability in the Real-Time Energy and Operating Reserve Market, net of Ramp Capability amounts in the Day-Ahead Energy and Operating Reserve Market.	[redacted]
Real-Time Ramp Capability Cost Distribution (RC_DIST)	The total daily charges or credits to an Asset Owners for Day-Ahead and net Real-Time Ramp Capability procurement cost.	[redacted]
Grand Total		[redacted]

5. **A summary of ENO's transmission charges and revenues from the previous twelve month period**

The HSPM table below provides a summary of ENO's transmission charges and revenues from the previous twelve month period.

Summary of ENO Transmission Charges and (Revenues)
From the previous 12 month period (January – December 2018)

[redacted]

[redacted]

6. Any changes approved by the ENO Operating Committee to the principles, practices, and protocols utilized to procure capacity and energy in MISO, including:

i. The manner of offering in generation and bidding and scheduling load into the Day-Ahead and Real Time Markets

The information responsive to this component of the filing has been designated as HSPM.

[redacted]

ii. ARR nominations

The information responsive to this component of the filing has been designated as HSPM.

[redacted]

iii. Other material aspects of any MISO-administered market interaction, if requested by the Advisors to the Council.

ENO is not aware of any further information requested by the Advisors to the Council.

7. Any unexpected material costs or market impediments that ENO is encountering within MISO

ENO has not encountered unexpected material market impediments since MISO integration. Starting February 1, 2016, ENO has been billed monthly for JOA Settlement charges under Schedule 49—Cost Allocation for Available System Capacity Usage. Since ENO's last

monitoring report, for the period February 2018 to January 2019, ENO was billed approximately $302,000 pursuant to Schedule 49.

8. A list identifying any existing, enhanced and/or supplemental records series to be incorporated under the Entergy System Records Management and Retention Policy necessary to facilitate retention of data required to support SPO operations in MISO on behalf of ENO

No further record series have been added beyond those reported previously.

c. MISO's Transmission Expansion Planning Process

1. Any proposed transmission projects by ENO and directives received by ENO from MISO to construct transmission

The transmission projects planned and proposed by ENO are posted on the Company's OASIS page[5] and are generally updated on a monthly basis. The posted report includes the status of the projects in the MTEP process.

On December 10, 2018, the MISO Board of Directors approved one ENO transmission project for MTEP18, Appendix A, Curran 230 kV substation breakers installation.

Two MTEP19 Target Appendix A projects were submitted by ENO to MISO in September 2018, and reviewed at the December 18, 2018, MTEP18 South Subregional Planning Meeting. MISO's presentation on this project is posted with the meeting materials.[6] At this meeting, economic planning discussions, including issues identification, also took place, and ongoing Generator Interconnection studies were reviewed. No economic issues were identified in Louisiana for MTEP19, though MISO is performing additional evaluation on the congestion at the Amite South interface in order to identify the drivers, assumed to be retirements and generator

5 http://www.oasis.oati.com/EES/EESdocs/Construction_Plan.htm

6 https://cdn.misoenergy.org/20181218%20SSPM%20Item%2003d%20Review%20of%20Reliability%20Projects%20LA301948.pdf

siting assumptions. ENO continues its active participation in MTEP19 and in the discussions that have begun on the MTEP20 and MTEP21 futures.

2. The status of developments within the MISO stakeholder process that could have a material effect on the allocation of MISO costs, including the cost of transmission investment included by MISO in its MTEP, to ENO.

With respect to transmission cost allocation principles, no material changes have been adopted since the Entergy Operating Companies joined MISO. However, MISO has filed Tariff revisions at FERC on several matters that could have a material effect on the allocation of MISO costs, to modify its regional planning criteria for projects with voltages of less than 345kV to qualify as Market Efficiency Projects (MEPs), to expand upon the metrics that will be used to evaluate the potential benefits attributable to economic transmission projects, and to provide clarity on the treatment of lower voltage projects that are determined by MISO to offer economic benefits that justify the construction of these projects, but do not meet the criteria of MEPs, including the voltage threshold. The filings are described in detail in Section 3 below.

3. Material changes, if any, proposed by MISO or MISO stakeholders to MISO's governance structure or allocation principles for the cost of transmission investment

i. Regional Planning

On February 25, 2019 MISO and the MISO Transmission Owners, including Entergy New Orleans, LLC made a joint filing in Dockets ER19-1124-000 and ER19-1125-000. Due to eTariff filing constraints, proposed Revisions to the Agreement of Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., A Delaware Non-Stock Corporation ("ISO Agreement") were unable to be packaged together with the proposed revisions to Attachment FF, the New Attachment FF-7 to expand, modify, and add clarity regarding the identification and cost allocation of transmission facilities providing regional and local economic benefits within the MISO footprint, and a proposed definition for Local Economic Projects in

Module A. Therefore, MISO submitted the ISO Agreement revisions in a separate filing in Docket No. ER19-1125. MISO requested that the two filing packages be treated as one.

The filings propose an expanded methodology for the identification and cost allocation of economically beneficial projects located in MISO based on existing and new benefit metrics, developed through the Regional Expansion Criteria Benefits ("RECB") Task Force (now RECB Working Group ("RECBWG")) and described in previous Post Integration Monitoring Reports submitted by Entergy New Orleans.

As described in the Transmittal Letter MISO submitted in Docket No. ER19-1124, the revisions proposed in the filing:

(1) modify cost allocation for Market Efficiency Projects using existing and newly-adopted metrics that allow for added precision in allocating costs and facilitate 100 percent allocation of Market Efficiency Project costs to benefitting Transmission Pricing Zones (eliminating the 20 percent allocation to all of MISO on a postage stamp basis);

(2) provide an expanded framework for the designation of Market Efficiency Projects at lower voltages, including lowering the voltage threshold from 345 kV to 230 kV, which:

a. incorporates the economic value measured by additional benefit metrics including the defined term for Targeted Appendix A Projects; and

b. provides a limited exception from the MISO Competitive Developer Selection Process for certain Immediate Need Reliability Projects that, because of the project hierarchy prescribed by the Tariff, also qualify as Market Efficiency Projects and could otherwise be delayed beyond the reliability need-by date without the limited exception; and

(3) add a project category for Local Economic Projects to formalize the criteria used to define and identify projects currently categorized as economic "Other" in MISO's existing planning framework.

The filing also proposes assigning the cost of Local Economic Projects ("LEP") to the Transmission Pricing Zone ("TPZ") in which they are located, unless they are located entirely outside of MISO, in which case a load flow test would be applied, with costs allocated to the TPZ receiving the highest percentage of flows in the MISO footprint, as a result of the LEP. Comments on these filings were due to FERC on March 27, 2019.

The following elements of MISO's Regional Cost Allocation Principles remain unchanged:

• Multi-Value Projects (MVP)

• Market Efficiency Projects (MEP):

– Benefit based allocation to all zones in MISO

– Benefit/Cost ratio that is greater than or equal to 1.25

– Minimum cost threshold of $5M

MISO continues with the benefit metrics discussions for MEPs that commenced in late 2015 with the release of a draft Market Efficiency Project issues paper. This discussion is focused on evaluation of potential additional benefit metrics for economic transmission projects. Policy discussions will be occurring at the RECBWG, supported by technical evaluations of potential metrics occurring through the Planning Subcommittee.

ii. **Interregional Planning**

- **MISO/PJM Order 1000 Compliance, Docket No. ER13-1943**. On February 28, 2019, MISO and the MISO Transmission Owners, including Entergy New Orleans, LLC made a (Section 205) filing in Docket No. ER19-1156, proposing Revisions to MISO Tariff to

Provide MISO Cost Allocation for Interregional Economic Projects "to provide a cost allocation methodology for MISO's share of the cost of certain Interregional Economic Projects ("IEPs") with PJM Interconnection L.L.C. ("PJM") and Southwest Power Pool, Inc. ("SPP"). As it relates to IEPs with PJM with voltages 100 kilovolts ("kV") or above but below 345 kV, this filing also complies with the directive set forth in Paragraph 51 of the Commission's January 19, 2017 "Order on Rehearing and Compliance" issued in Docket No. EL13-88-001, et al., requiring MISO to explain and/or propose a cost allocation method for such projects. An effective date of 120 days from the date of filing, June 28, 2019, was requested.

- **NIPSCO Complaint, Docket No. EL13-88. NIPSCO Complaint, Docket No. EL13-88.** On February 28, 2019, MISO filed a Compliance Report in Docket No.ER13-88 and ER16-1969, the NIPSCO Complaint, that has been described in previous Post-Integration Monitoring reports, that described and included, for informational purposes only, redlined and clean Tariff sheets submitted with the Interregional Cost Allocation in Docket No. ER19-1156.

iii. Cost Allocation

On October 12, 2018, MISO filed proposed revisions to Attachment WW of its Open Access Transmission, Energy and Operating Reserve Markets Tariff to modify the boundaries of the Cost Allocation Zones to create a stand-alone zone for Entergy New Orleans, LLC at the request of the Council of the City of New Orleans in order to further the alignment of costs and beneficiaries for MEPs and other economic projects approved in MISO's Transmission Expansion Plan ("MTEP") where Attachment WW is applicable. MISO requested an effective date of 60

days from the date of filing, but no later than December 31, 2018. On December 11, 2018, FERC issued an Order approving the filing in Docket ER19-98-000.

d. Interim Cost-Benefit Analysis

Please see Attachment 4, which provides the calculation of MISO energy- and capacity-related savings through 2017.[7] Also, please see Attachment 5, which provides the calculation of MISO energy- and capacity-related savings through 2018.

1. **Identification of any material changes to ENO's generation portfolio, such as the retirement or addition of a long-term resource, and an estimate of the impact of that change (if any) on the savings identified in the Interim Cost-Benefit Analysis**

   There were no material changes to ENO's generation portfolio in 2018.

Respectfully Submitted:

By: _____

Timothy S. Cragin, Bar No. 22313
Harry M. Barton, Bar No. 29751
639 Loyola Avenue, Mail Unit L-ENT-26E
New Orleans, Louisiana 70113
Telephone: (504) 576-6571
Facsimile: (504) 576-5579

ATTORNEYS FOR
ENTERGY NEW ORLEANS, LLC

[7] ENO's Fourth Annual Post-Integration Report stated, at page 2, that as of the date of filing the Advisors and ENO had initiated discussions regarding an updated methodology for calculating benefits to ENO customers resulting from the Company's continued membership in MISO, and that ENO would supplement the Fourth Annual Report when the updated analysis for 2017 was available. Because that analysis was not available until February 2019, the Company is including the 2017 analysis along with the 2018 analysis in this Fifth Annual Report rather than separately supplementing and refiling the Fourth Annual Report.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

INVESTIGATION OF THE POTENTIAL COSTS AND BENEFITS OF ENTERGY NEW ORLEANS, INC. AND ENTERGY LOUISIANA, LLC JOINING A REGIONAL TRANSMISSION ORGANIZATION VERSUS CONTINUATION OF THE ENTERGY INDEPENDENT COORDINATOR OF TRANSMISSION WITH ENHANCEMENTS	)))))))))	**DOCKET NO. UD-11-01**

ATTACHMENT 1

HIGHLY SENSITIVE PROTECTED MATERIAL

INTENTIONALLY OMITTED

MAY 2019

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

INVESTIGATION OF THE POTENTIAL COSTS AND BENEFITS OF ENTERGY NEW ORLEANS, INC. AND ENTERGY LOUISIANA, LLC JOINING A REGIONAL TRANSMISSION ORGANIZATION VERSUS CONTINUATION OF THE ENTERGY INDEPENDENT COORDINATOR OF TRANSMISSION WITH ENHANCEMENTS	)))))))))	**DOCKET NO. UD-11-01**

ATTACHMENT 2

HIGHLY SENSITIVE PROTECTED MATERIAL

INTENTIONALLY OMITTED

MAY 2019

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

INVESTIGATION OF THE POTENTIAL COSTS AND BENEFITS OF ENTERGY NEW ORLEANS, INC. AND ENTERGY LOUISIANA, LLC JOINING A REGIONAL TRANSMISSION ORGANIZATION VERSUS CONTINUATION OF THE ENTERGY INDEPENDENT COORDINATOR OF TRANSMISSION WITH ENHANCEMENTS	)))))))))	**DOCKET NO. UD-11-01**

ATTACHMENT 3

HIGHLY SENSITIVE PROTECTED MATERIAL

INTENTIONALLY OMITTED

MAY 2019

MISO Historical Benefits Calculation

Results of 2017 Analysis

January 2019

Background and key objectives of the changes to the MISO cost/benefit analysis

- The fundamental construct and objective of the historic MISO cost/benefit analysis have not changed
  - The 2017 analysis estimates the benefits of MISO participation relative to non-RTO operations, as has been done each year since joining MISO (2014-2016)
- However, the 2017 analysis reflects changes to the methodology used to develop the estimates
- The changes address the need to develop a more simplified approach that is reasonable and avoids, if possible:
  - Comparisons to a static historical period (that becomes less meaningful as we move further away from this period)
  - The need to normalize for effects unrelated to joining MISO (e.g. changes in gas prices, changes in generation resources and transmission topology, changes in System Agreement participation)
  - The introduction of material new components to the analysis.

Key features of the new energy-related cost/benefit calculation

- Identify ENOL's resources used in MISO in each hour -- generation (owned and controlled), purchases, and sales
- Determine whether the purchases and sales would have occurred had ENOL not joined an RTO and, instead, operated as a standalone Balancing Authority (BA)
  - Do this by including impediments to trade used in other ENOL analyses[1]
  - For each purchase and sale that would have occurred, estimate what the benefit would have been in a standalone BA
- Determine whether additional generator commitment would have been required for operations in a standalone BA
  - If generator commitment in MISO would not meet standalone BA flexibility needs, identify the additional commitment necessary to do so
- Quantify savings by summing the differences in margins, generator costs, and administrative charges.

[1] For example, the forward-looking analysis supporting ENOL's Renewal Filing.

Key features of the new capacity-related cost/benefit calculation

- The general structure of the capacity-related cost/benefit calculation has not changed -- it is still based on two main items:
  - A comparison of the MW of long-term planning reserves required in MISO versus the MW of long-term planning reserves that would have been required had ENOL not joined an RTO
  - An estimate of the value of this difference in MW -- the avoided cost of the additional planning reserves -- based on the long-term cost of capacity
- However, the inputs to these two main items warranted updates:
  - MISO's calculation of its planning reserve margin (PRM) has changed since 2011
    - The MISO PRM is used to estimate long-term planning reserves required in MISO
  - The long-term cost of capacity has changed since 2011 as long-term capacity markets have generally tightened.

Key features of the new capacity-related cost/benefit calculation

- Changes reflected in the 2017 capacity-related cost/benefit calculation:

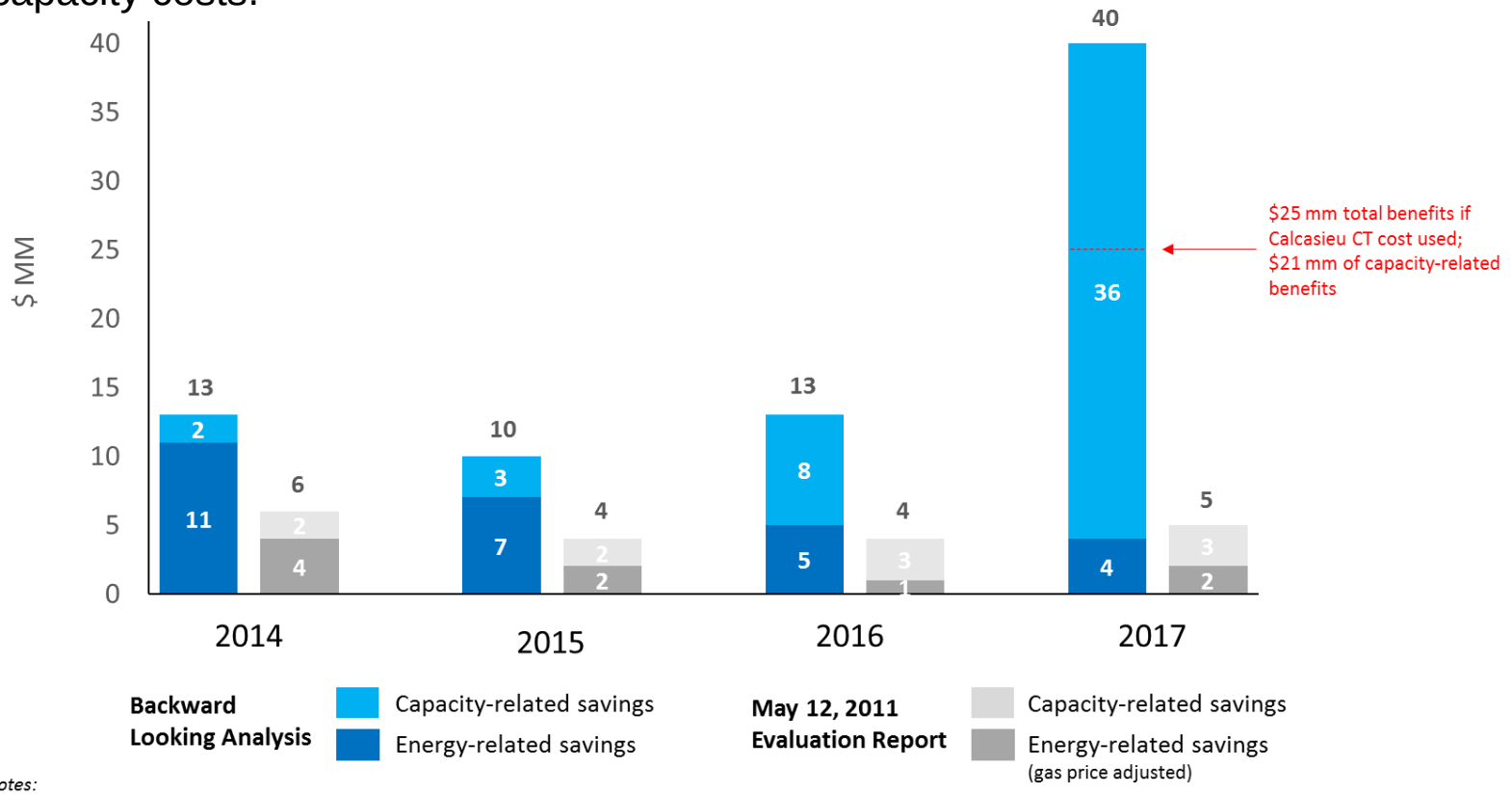
Item	Old inputs if applied to 2017	New inputs applied to 2017
A. Estimate of long-term planning reserves required in MISO	12% of ENOL's 2017 non-coincident peak • Consistent with MISO's calculation in 2011 and with the 2011 Evaluation Report	MISO's current calculation of annual requirements utilizing ENOL's EFORd[2] and coincident peak with MISO • Consistent with recent forward-looking MISO benefits calculation
B. Estimate of long-term planning reserves required in standalone BA	49% of ENOL's 2017 non-coincident peak load • Consistent with 2016 calculation and recent forward-looking calculation[1]	Same as old input
C. Cost of long-term capacity	Calcasieu CT cost • Consistent with the 2011 Evaluation Report and then-recent (2008) market information	New CT cost • Consistent with recent market information (i.e. RFP results)
Estimate of capacity-related cost/benefits	= (B – A) x C	= (B – A) x C

[1] The 2016 capacity-related cost/benefit calculation reflects termination of the ESA after August 2016. The 49% standalone value was used for the September 2016 through December 2016 period. The 49% standalone value is based on SPO's SERVM analysis.

[2] EFORd = equivalent forced outage rate demand. For purposes of developing an estimate of long-term planning reserves required in MISO, ENOL used a 10-year average EFORd, not the current planning year EFORd used in MISO's annual calculation. If the current planning year EFORd were used to estimate long-term planning reserves required in MISO, then year-to-year fluctuations in EFORd -- whether increases or decreases -- would be reflected in the analysis and potentially lead to unreasonable results. Year-to-year fluctuations in EFORd that result in changes in annual required reserves are not necessarily indicative of long-term expectations and are appropriately evaluated using a short-term cost of capacity, not a long-term cost of capacity.

Results of the 2017 MISO cost/benefit calculation

- 2017 energy-related benefits are in-line with previous estimates
- 2017 capacity-related benefits are significantly higher than previous estimates
  - This is primarily due to the impact of ESA termination and the increase in long-term capacity costs.



Notes:

-- The May 12, 2011 Evaluation Report assumed continuation of the ESA for all OpCos except EAL thru 2015, and all OpCos except EAL and EML thereafter. The Backward-Looking analysis reflects continuation of the ESA for all OpCos except EAL thru November, 2015, for all OpCos except EAL and EML thru August, 2016, and termination of the ESA thereafter.

-- Energy-related savings include incremental administrative costs.

-- 2017 capacity-related savings reflects the impact of forced outage rates on MISO requirements but not on standalone requirements.

Impact of ESA termination and increase in long-term capacity prices

- ENOL's 2016 capacity-related cost/benefits estimate would have more than doubled had the ESA been terminated for the full year as opposed to one-third of the year
  - Changing this one input would have increased ENOL's 2016 capacity-related benefits estimate from $8 million to $17 million
- ENOL's 2016 capacity-related cost/benefits estimate would have increased by another $12 million (to $29 million) had updated long-term capacity cost information been used as opposed to the cost of the Calcasieu CT transaction
  - Updated long-term capacity costs are estimated to be over 70% higher than the Calcasieu CT transaction ($68 versus $40 per KW-year, in 2016)
- These two changes represent the majority of the increase in capacity-related cost/benefits between 2016 and 2017.

MISO Historical Benefits Calculation

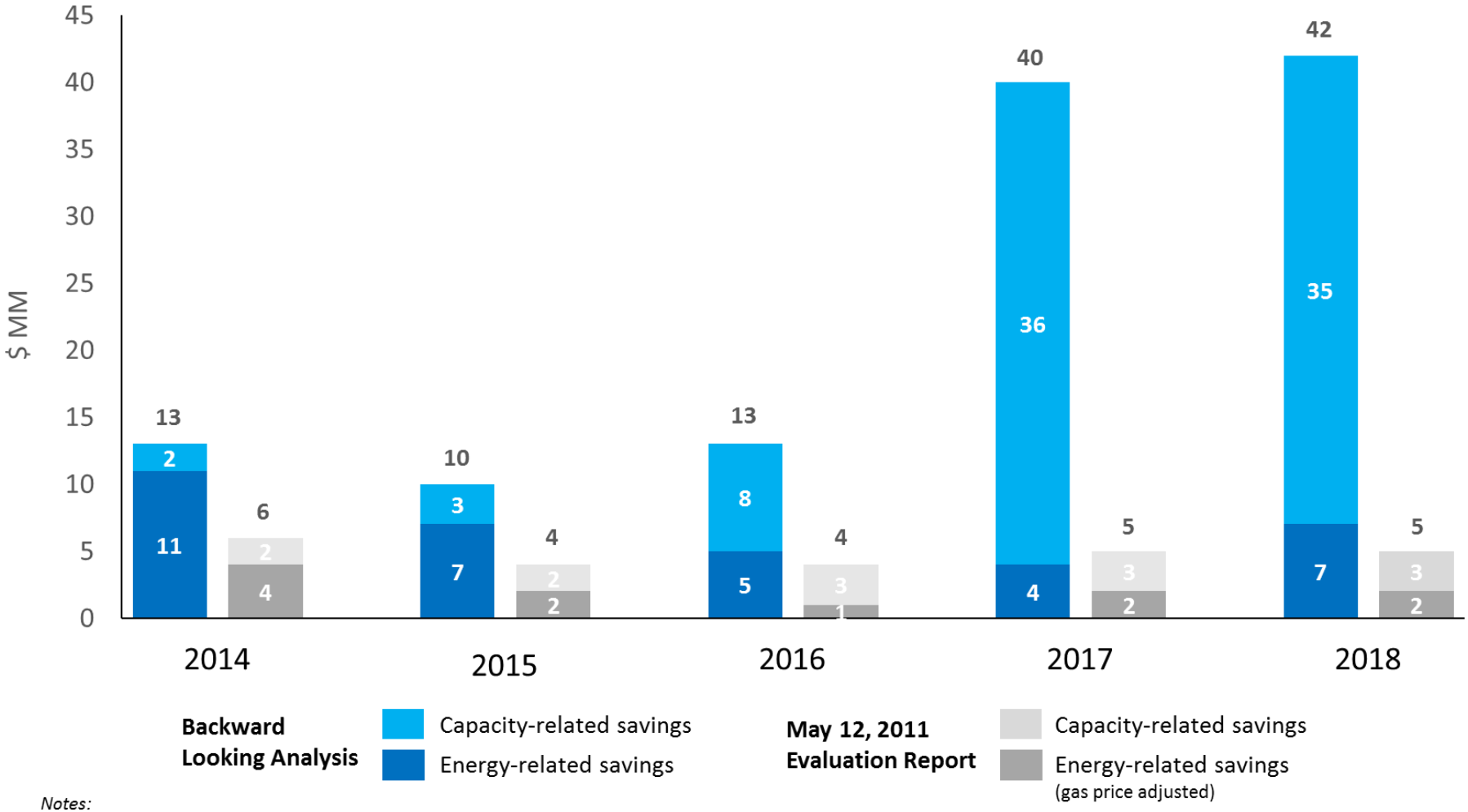
Results of 2018 ENOL Analysis

March 2019

Key features of the 2018 calculation

- The 2018 calculation uses the same analytic structure as the 2017 calculation
- However, it updates the inputs to the calculation, including:
  - 2018 generation, purchases, sales, load, and administrative costs for the energy-related cost/benefit analysis
  - 2018 PRM and unit outage information for the capacity-related cost/benefit analysis
- The 2018 results are generally in-line with 2017 results.

Estimate of ENOL's benefits from MISO participation



Notes:

-- The May 12, 2011 Evaluation Report assumed continuation of the ESA for all OpCos except EAL thru 2015, and all OpCos except EAL and EML thereafter. The Backward-Looking analysis reflects continuation of the ESA for all OpCos except EAL thru November, 2015, for all OpCos except EAL and EML thru August, 2016, and termination of the ESA thereafter.

-- Energy-related savings include incremental administrative costs.

-- 2017 and 2018 capacity-related savings reflects the impact of forced outage rates on MISO requirements but not on standalone requirements.

CERTIFICATE OF SERVICE
Docket No. UD-11-01

I, the undersigned counsel, hereby certify that a copy of the above and foregoing has been served on the persons listed below by facsimile, by hand delivery, by electronic mail, or by depositing a copy of same with the United States Postal Service, postage prepaid, addressed as follows:

Ms. Lora W. Johnson, CMC, LMMC
Clerk of Council
Council of the City of New Orleans
City Hall - Room 1E09
1300 Perdido Street
New Orleans, LA 70112

Erin Spears, Chief of Staff
Connolly A. F. Reed, Executive Assistant
Bobbie Mason
Council Utilities Regulatory Office
City of New Orleans
City Hall, Room 6E07
1300 Perdido Street
New Orleans, LA 70112

Andrew Tuozzolo
Chief of Staff to CM Moreno
City Hall – 2W40
1300 Perdido St.
New Orelans, LA 7112

David Gavlinski
Council Chief of Staff
New Orleans City Council
City Hall, Room 1E06
1300 Perdido Street
New Orleans, LA 70112

Sunni LeBeouf
City Attorney Office
City Hall, Room 5th Floor
1300 Perdido Street
New Orleans, LA 70112

Norman White
Department of Finance
City Hall, Room 3E06
1300 Perdido Street
New Orleans, LA 70112

Hon. Jeffrey S. Gulin
Hearing Officer
3203 Bridle Ridge Lane
Lutherville, MD 21093

Clinton A. Vince
Presley R. Reed, Jr.
Emma F. Hand
Dentons US LLP
1900 K Street, NW
Washington, DC 20006

Basile J. Uddo
J. A. "Jay" Beatmann, Jr.
c/o Dentons US LLP
650 Poydras Street, Suite 2850
New Orleans, LA 70130

Philip J. Movish
Joseph W. Rogers
Victor M. Prep
Legend Consulting Group
6041 South Syracuse Way, Suite 105
Greenwood Village, CO 80111

Errol Smith
Bruno and Tervalon
4298 Elysian Fields Avenue
New Orleans, LA 70122

Brian L. Guillot
VP, Regulatory Affairs
Entergy New Orleans, LLC
Mail Unit L-MAG-505B
1600 Perdido Street
New Orleans, LA 70112

Timothy S. Cragin
Harry M. Barton
Alyssa Maurice-Anderson
Entergy Services, LLC
Mail Unit L-ENT-26E
639 Loyola Avenue
New Orleans, LA 70113

Polly S. Rosemond
Seth Cureington
Derek Mills
Kevin T. Boleware
Entergy New Orleans, LLC
Mail Unit L-MAG-505B
1600 Perdido Street
New Orleans, LA 70112

Joseph Romano, III
Suzanne M. Fontan
Therese Perrault
Entergy Services, LLC
639 Loyola Avenue
Mail Unit L-ENT-4C
New Orleans, LA 70113

John H. Chavanne
Chavanne Enterprises
111 West Main Street, Suite 2B
New Roads, LA 70760-3509

Harold Marchand
Sewerage and Water Board of New Orleans
625 St. Joseph Street, Room 201
New Orleans, LA 70165

Ernest L. Edwards, Jr.
The Law Offices of Ernest L. Edwards, Jr.,
300 Lake Marina Avenue, Unit 5BE
New Orleans, LA 70124

James R. Dauphinais
Brubaker & Associates, Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

Mr. Fred M. Muzurski, CEM, CDSM
Senior Manager
Entergy USG Corporation
550 West Adams Street
Chicago, IL 60661-3676

Rick Boyd
The Folger Coffee Company
14601 Old Gentilly Road
New Orleans, LA 70129

Logan Atkinson Burke
Sophie Zaken
Alliance for Affordable Energy
4505 S. Claiborne Avenue
New Orleans, LA 70125

David L. Guerry
Jamie Hurst Watts
Long Law Firm, L.L.P.
1800 City Farm Drive, Building 6
Baton Rouge, LA 70806

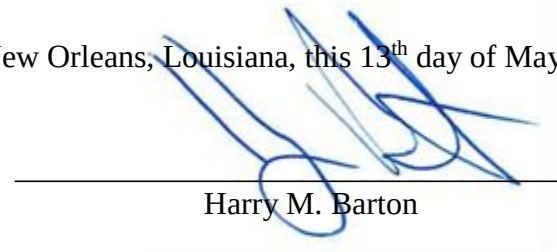
Walter C. Ferguson
MISO Senior Corporate Counsel
Two Lakeway
3850 N. Causeway Boulevard, Suite 442
Metairie, LA 70002

Erin E. Cullum
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223

Andrew B. Ezell
Ezell Law Firm, LLC
10761 Perkins Road, Suite A
Baton Rouge, LA 70810

Frederick H. Ritts
F. Alvin Taylor
Holland & Knight LLP
800 17th Street N.W., Suite 1100
Washington, DC 20006

New Orleans, Louisiana, this 13th day of May 2019.



Harry M. Barton