BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-16-02**

DIRECT TESTIMONY

OF

PHILIP J. MOVISH

ON BEHALF OF

THE ADVISORS TO THE

COUNCIL OF THE CITY OF NEW ORLEANS

NOVEMBER 20, 2017

PREPARED DIRECT TESTIMONY

OF

PHILIP J. MOVISH

I. INTRODUCTION

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

A. My name is Philip J. Movish. My business address is 8055 East Tufts Avenue, Suite 1250, Denver, Colorado. I am an Executive Consultant with the firm Legend Consulting Group Limited ("Legend").

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Advisors to the Council of the City of New Orleans ("Council" or "CNO"). The Council regulates the rates, terms, and conditions of electric and gas service of Entergy New Orleans, Inc. ("ENO"). ENO is one of the Entergy Operating Companies[1] and is a wholly-owned subsidiary of Entergy Corporation ("Entergy").

Q. PLEASE SUMMARIZE YOUR RELEVANT EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. Exhibit No. ___ (PJM-2) provides a summary of my relevant education and professional experience and Exhibit No. ____(PJM-3) lists my previous testimony.

Q. PLEASE DESCRIBE YOUR UTILITY TRANSMISSION & DISTRIBUTION PLANNING AND OPERATIONS EXPERIENCE.

A. I have been employed in the electric utility industry professionally for forty-seven years, both for publicly-owned utilities and investor-owned utilities, and utility consulting firms. In that time, my career has centered on transmission and distribution system planning, project commissioning, and operations. My representative project experience includes:

- Responsible annually for the performance of load flow and stability studies and development of ten-year transmission expansion plans for a northeastern Investor Owned Utility.
- Commissioning and startup of newly constructed transmission substations.
- Planning studies investigating the proposed installation of a 345 kV transmission phase shifter.
- Storm restoration transmission damage assessments and repair coordination.
- Transmission outage coordination with system operating personnel.
- Commissioning of under-frequency load shedding relay protection schemes and remote wireless substation voltage control systems.
- Member of the New England Power Pool ("NEPOOL") Transmission Planning Committee performing regional transmission load flow studies.
- Responsible for performance of load flow and stability studies of a proposed 800 mile bipolar three terminal HVDC transmission project between Canada and the U.S.
- Transmission siting and interconnection studies for numerous proposed generating facilities.
- Member of the Mid-Continent Area Power Pool ("MAPP") Generation Reliability Committee performing regional load flow studies.

[1] The Entergy Operating Companies ("Operating Companies") are Entergy Arkansas, Inc. ("EAI"); Entergy Louisiana, LLC ("ELL"); Entergy Mississippi, Inc. ("EMI"); Entergy Texas, Inc. ("ETI"); and ENO.

- Performance of load flow studies concerning numerous generating facility projects, both domestically and internationally.

- Involved in every ENO transmission and distribution matter that has come before the Council in the past twenty years including the rebuilding of ENO's transmission and distribution systems after Hurricane Katrina.

- Member of the Entergy Regional State Committee Working Group ("ERSCWG") as a designated representative of the Council involved in the analysis of MISO transmission matters.

- Member Proxy of the Organization of MISO States on behalf of the Council involved in analyzing and developing state regulatory positions on MISO matters.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide the results of my review related to 1) ENO's June 20, 2016, "*Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief*" ("Initial Application"), 2) ENO's November 18, 2016 Supplemental Direct Testimony ("Supplemental Testimony") and, 3) ENO's July 6, 2016, "*Supplemental and Amending Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief*" ("Supplemental Application"). I refer to the Initial Application, November 18, 2016 Supplemental Direct Testimony, and the Supplemental Application collectively as the "Application". Further, based upon that review, to provide my conclusions regarding the Application to the Council. My testimony concentrates on my evaluation of the proposed alternatives ENO has presented in the Application, from a transmission reliability and operational risk basis.

Q. PLEASE SUMMARIZE YOUR MAJOR CONCLUSIONS.

A. In my testimony, I present my review of ENO's application to construct NOPS based on the need to mitigate ENO's transmission reliability issues. From my review, I conclude that the CT Alternative would fully mitigate ENO's transmission reliability issues without the need to construct any transmission upgrades. However, as Advisor Witness Joseph Rogers has testified ENO has not justified the capacity need of the CT Alternative and has concerns related to its operational limitations. Given ENO's stated constructability issues and unknowns concerning ENO's accomplishment of required transmission upgrades needed to mitigate its transmission reliability issues, I conclude that the Transmission Alternative, either with or without the inclusion of 2 percent DSM and solar photovoltaic PV capacity, presents significant reliability risk to New Orleans customers. As noted, to the extent the Council approves proceeding with this option absent the demonstration that it is realistically achievable given the number of unknowns related to the feasibility of constructing needed transmission upgrades, ENO should demonstrate to the Council that its proposed transmission upgrade projects can be timely constructed, the refined cost of each project, the potential impacts of project delay on ENO's transmission reliability, and the definitive total costs for the alternative prior to final approval.

I conclude that, of the cases modeled, my preferred alternative is construction of the Reciprocating Internal Combustion Engine ("RICE") generator sets ("RICE Alternative"), with or without consideration of 2 percent DSM and solarPV capacity, including the transmission upgrades required to fully mitigate ENO's transmission reliability issues. The RICE Alternative presents the least risk compared to both the CT Alternative and the Transmission Alternative. If selected, the RICE Alternative also would provide other significant benefits to New Orleans, including operational flexibility, dynamic system support for voltage regulation, on-site black start capacity to support restoration of service after a major outage or storm event, and the ability to provide a source of power to ENO's critical loads in the event of an outage. Further, the RICE Alternative, subject to further study, could potentially provide a source of power for the Sewerage & Water Board's ("S&WB") Carrolton facility in the event that S&WB's generation was impaired or inoperable.

In considering the alternatives ENO has presented, it is important to note that inconsistencies in assumptions exist in ENO's transmission reliability analysis model. Namely the updated load forecast doesn't correctly account for the Council's 2 percent DSM goal. In addition, the capacity value of installed solar PV capacity is in disagreement with ENO's economic analysis in the amount of 15 MW per 100 MW of installed solar PV capacity. The impact of these inconsistencies on the study results is unknown. For this reason, ENO should be directed by the Council to demonstrate that such assumptions have been applied correctly in its analyses.

II. <u>ENO'S APPLICATION BEFORE THE COUNCIL</u>

Q. WHAT IS ENO SEEKING IN ITS APPLICATION IN THIS DOCKET?

A. In the Supplemental Application, ENO seeks authorization to proceed with constructing the New Orleans Power Station ("NOPS" or the "Project"). In the Initial Application, the Project consisted of an approximately 226 MW (summer rating) Combustion Turbine Generator ("CT"). In Supplemental Application, ENO amends the Initial Application to include an alternative to the original Project configuration. As an alternative, the Company proposes an approximately 126 MW project, consisting of seven RICE generator sets. ENO proposes that either facility, if approved by the Council, would be located at ENO's existing Michoud facility in New Orleans East. **Q. PLEASE DESCRIBE BOTH PROPOSED CONFIGURATIONS OF THE NEW ORLEANS POWER STATION.**

Q. The CT Alternative is a 226 MW (summer rating) natural gas-fired plant consisting of one Mitsubishi Hitachi Power Systems America ("MHPSA") 501 GAC CT. The CT Alternative is proposed to be located at ENO's Michoud facility in New Orleans East and will be constructed by Chicago Bridge & Iron ("CB&I") under an Engineer, Procure, and Construct (EPC) contract. The estimated total project cost is $232 million, or approximately $1,026 per kW, and includes: the EPC cost, Entergy project management, Allowance for Funds Used During Construction ("AFUDC"), project contingency and the costs necessary to interconnect to the switchyard. The CT Alternative includes natural gas compressors to ensure sufficient gas pressure at the fuel inlet of the CT. As currently designed, the CT Alternative has a 1 MW emergency diesel generator to supply vital auxiliary loads in the event of a complete power loss, but the diesel generator is too small for the CT Alternative to have "black start" capability. Under the current procedural schedule, the CT Alternative, if approved, would be expected to achieve commercial operation in March 2021. This date assumes that any regulatory approval would be provided by the Council by the end of February 2017 and Notice to Proceed ("NTP") would be provided to the EPC contractor by March 1, 2018.

The RICE Alternative is a 128 MW natural gas-fired plant consisting of seven Wärtsilä 18V50SG RICE generator sets. The RICE Alternative is proposed to be located at ENO's Michoud facility in New Orleans East and will be constructed by Burns and McDonnell ("B&M") under an EPC contract. The estimated total project cost is $210 million, or approximately $1,640 per kW, and includes: the EPC cost, Entergy project management, AFUDC, project contingency and the costs necessary to interconnect to the switchyard. The RICE Alternative includes a diesel generator and compressed air black start capability in the event of a complete power loss. Under the Council's current procedural schedule, the RICE Alternative, if approved, would be expected to achieve commercial operation in February 2020. This date assumes that any regulatory approval would be provided by the Council by the end of February 2017 and Notice to Proceed ("NTP") would be provided to the EPC contractor by March 1, 2018.

III. <u>TRANSMISSION RELIABILITY BENEFITS OF NOPS</u>

Q. CAN YOU PLEASE DESCRIBE THE BENEFITS OF LOCATING GENERATION AT THE EASTERN END OF ENO'S SYSTEM?

A. As a general rule, location of generation near the load which it serves provides significant benefits. This is especially important given that ENO's system is at the extreme eastern end of the Down Stream of Gypsy ("DSG") load pocket which is a transmission constrained area. Further, the existing transmission topology of ENO's system is significantly constrained. The retirement of ENO's Michoud Units 2 and 3 in 2016 has increased the stress on ENO's transmission system which at present relies totally on imports of power to serve ENO's load.

Having local generation would support reliable operation of ENO's system under both normal operating conditions and in the event of both planned and unplanned transmission system outages. Reliable electric system operation requires an adequate supply of reactive power to meet the electrical requirements of electric pumps and motors. The unit of measurement of reactive power is VARS[2]. Local generation provides a local source of effective dynamic reactive power (VARS) to meet such needs, maintain system voltage within acceptable limits, and reduce the potential for voltage instability. Voltage instability occurs when the electric system does not have an adequate supply of VARS to meet the reactive power requirements of the load being served which could result from transmission contingencies leading to a voltage collapse of the system. In addition, local generation would positively support accelerated restoration of service to customers following major system disturbances than otherwise would be possible, and with selective switching, could provide a source of power to critical customer loads until the system is restored back to normal operation. As New Orleans is prone to major storm events, which historically have resulted in significant transmission disruptions to both ENO's transmission system and transmission lines in DSG to which ENO interconnects, having local generation would support ENO's ability to continue to serve its customers until full restoration of transmission service is accomplished.

Q. YOU INDICATED THAT LOCAL GENERATION COULD POTENTIALLY BE UTILIZED AS A SOURCE OF POWER TO ENO'S CRITICAL LOADS IN THE EVENT OF A MAJOR STORM EVENT. PLEASE ELABORATE.

A. Relative to powering ENO's critical loads in the event of a major storm event, based upon my review of ENO's transmission system topology, I believe a "cranking path"[3] potentially exists for local generation located at Michoud, such as ENO's CT Alternative unit or RICE Alternative to potentially provide power to the Sewerage & Water Board of

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[2] Volt-Ampere-Reactive

[3] A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.

New Orleans' ("S&WB") Carrolton pumping plant, in the event of an islanding event that results in ENO's transmission lines that import power being out of service. In a situation where ENO's system is without power and the City is flooding (as has occurred as a result of major storms and hurricanes), and the S&WB's generating capacity is impaired; local generation could potentially be utilized as a reliable back-up source of power to ensure that the S&WB's pumps keep pumping.

Q. WHAT WOULD ENO HAVE TO DO TO VERIFY YOUR OBSERVATION THAT LOCAL GENERATION COULD POTENTIALLY BE USED TO SUPPLY S&WB AS A BACKUP MEASURE?

A. To verify the feasibility of this concept, ENO would have to identify a suitable "cranking path", and perform load flow, and steady-state and transient stability studies, develop an operating guide and switching plan, as well as develop a plan to coordinate operations with the S&WB. As I discuss in further detail later in my testimony, in my opinion having black start capability would be critical to insuring that local generation could be depended upon to power S&WB's Carrolton pumping plant, in the event of a failure of S&WB's generators during critical flooding events.

Q. WOULD YOU EXPECT NOPS TO BE OPERATED DURING NORMAL SYSTEM CONDITIONS?

A. Yes. Owing to the transmission constrained nature of the DSG load pocket, and ENO's transmission system limitations, local generation has been operated historically during high load periods to support system reliability in order to protect against the unplanned outage of external DSG generation and/or transmission, and to provide a local source of reactive power to maintain system voltage within acceptable limits. Such generators are called Reliability Must Run ("RMR") units. Historically, ENO's Michoud Units 2 and 3 provided this function as Entergy designated RMR units operated under the requirements of an Entergy Operating Guide. Similarly, upon ENO becoming a member of the Mid-Continent Independent System Operator ("MISO") on December 19, 2013, MISO designated Michoud Units 2 and 3 as Voltage and Local Reliability ("VLR")[4] units under the requirements of a MISO Operating Guide[5]. I would fully expect that either the CT Alternative or the RICE Alternative would be designated a VLR unit by MISO, and would be operated in a similar manner to ENO's Michoud units in support of both ENO's and DSG's system reliability. ENO witness Charles Long indicates a similar opinion in his Direct Testimony at page 5, lines 11-14.

IV. <u>ENO'S COMPLIANCE WITH NERC TRANSMISSION RELIABILITY STANDARDS</u>

Q. PLEASE DESCRIBE THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION.

A. The North American Electric Reliability Corporation ("NERC") is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the

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[4] The terms "RMR" and "VLR" have the same meaning and are operated for the same reasons.

northern portion of Baja California, Mexico. NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people.

Q. PLEASE DESCRIBE THE NERC TPL-001-4 STANDARD?

A. The NERC TPL-001-4 Standard ("Standard") establishes transmission system planning performance requirements. Under the Standard, each utility "Transmission Planner" and "Planning Coordinator" is required to prepare annually a long-term forward-looking Planning Assessment ("Assessment") of its portion of the "Bulk Electric System" ("BES"). The Assessment analyzes the performance and reliability of the transmission system under a broad range of single and multiple contingency conditions, in order to identify transmission reliability violations. Whenever the analyses indicate the inability of the transmission system to meet the reliability performance requirements established under the Standard, the "Transmission Planner" is required to develop a "Corrective Action Plan" to eliminate the violations in order to ensure that their portion of the BES achieves and maintains acceptable reliability under both normal system conditions, and in the event of the occurrence of single and multiple contingency events. Amongst other things, the analyses are used to identify the most critical single element and multiple element contingencies of each category defined by NERC resulting in transmission reliability violations under the Standard. Exhibit No.___ (PJM-4) provides a copy of the NERC TPL-001-4 Standard

[5] See ENO response to SIE 4-13 c-d for a discussion of DSG RMR and VLR commitments.

Q. DOES ENO MAINTAIN A PLAN TO ENSURE ITS COMPLIANCE WITH THE STANDARD?

A. Yes. ENO witness Charles Long indicates in his Direct Testimony, at page 6 in the Answer to Question 9, that ENO maintains a plan to ensure compliance with the Standard over a ten-year planning horizon. ENO has provided copies of its reports titled "Entergy Assessment of Entergy Transmission System Pursuant to NERC TPL Standards" ("Assessment Reports") and supporting steady state and stability analyses and modeling information in response to Advisors 3-1, 3-3, 3-4, and 3-5[6]. ENO's analyses cover the full range of single element and multiple element contingencies.

Q. CAN YOU EXPLAIN THE TERMS "STEADY STATE", "STABILITY ANALYSES", "SINGLE ELEMENT", AND "MULTIPLE ELEMENT CONTINGENCIES" AS USED IN TRANSMISSION PLANNING AND MODELING?

A. As used in transmission planning and modeling, "steady state" refers to the analysis of a power system's performance in the event of the unplanned outage of a transmission line, substation equipment failure, etc. Steady state analysis is performed to identify potential reliability issues for development of plans to mitigate any reliability issues identified, such as transmission line upgrades. "Stability" refers to the ability of a power system to bring itself back to its stable configuration following either a small or large system disturbance, such as power flows exceeding the maximum amount of power that can flow

[6] Such reports and analyses have been designated as Critical Energy Infrastructure Information (CEII) by ENO, the details of which can only be shared with appropriate Reviewing Representatives in accordance with the CEII Confidentiality Agreement in effect in this docket.

through a transmission system. “Single element” refers to the loss of a single transmission element, such as a transmission line or transformer, etc. “Multiple element” refers to the loss of more than one transmission element, such as the loss of two transformers.

Q. IN YOUR REVIEW OF THE APPLICATION HAVE YOU REVIEWED ENTERGY’S ASSESSMENT REPORTS, STEADY STATE AND STABILITY ANALYSES, AND ASSOCIATED MODELING INFORMATION?

A. Yes. I have reviewed the steady state and stability analyses and associated modeling information which form the basis of Entergy’s Assessment Reports covering the 2016 - 2025 period.

Q. DO ENTERGY’S ANALYSES IDENTIFY ENO’S MOST CRITICAL TRANSMISSION CONTINGENCIES?

A. Yes. The analyses indicate that ENO’s most critical contingencies resulting in transmission reliability violations per the Standard would be the occurrence of a NERC Category P2.3 or P6 contingency. A P2.3 contingency is a single contingency internal breaker fault of a non-bus-tie breaker which results in a system fault which must be cleared by protection on both sides of the affected breaker. A P6 contingency is a multiple contingency initiated by the loss of a transmission circuit, transformer, shunt device, or single pole of a DC line, followed by system adjustments, followed by the loss of an additional transmission circuit, transformer or shunt device. Though the occurrence of a P6 contingency is a low probability event, the consequences to ENO’s customers of such an event are not! In ENO’s case, the P6 contingency would sever ENO’s 230 kV and 115 kV transmission networks. This would essentially eliminate the transmission system's ability to deliver power to the majority of ENO's customers. As a result, ENO's 115 kV network would suffer a voltage collapse placing approximately 49,000 ENO customers out of service.

Q. CAN YOU PLEASE EXPLAIN THE RESULTS OF ENTERGY'S ASSESSMENT COVERING THE 2017 PERIOD?

A. Entergy's Assessment completed in December, 2016 covering the 2017 period reflects the retirement of Michoud Units 2 and 3 without any generation additions in ENO's service territory. From my review, the results of the Assessment indicate that after the retirement of the Michoud Units, and without adding any new generation, ENO's system is presently at risk of transmission reliability violations.

Under NERC Transmission Reliability Standards, a Corrective Action Plan is required to insure the future transmission reliability of ENO's system. In this docket, ENO has provided its plan based upon its performance of analyses to fully mitigate such transmission reliability risks.

V. <u>REVIEW OF ENO'S TRANMSMISSION RELIABILITY ANALYSES</u>

Q. HAVE YOU REVIEWED ENO'S TRANSMISSION RELIABILITY ANALYSES PERFORMED IN SUPPORT OF NOPS?

A. Yes. I reviewed both the transmission analyses[7] performed by ENO in support of its initial Application filed in this docket, and the transmission analyses performed by ENO in support of its Supplemental Application. My direct testimony is limited to my review and observations of the transmission analyses performed by ENO in support of its Supplemental Application, as such analyses reflect ENO's updated load forecast and project alternatives, with the exceptions noted hereinafter.

It should be noted that the updated load forecast reflected in ENO's transmission reliability analyses is in dis-agreement with ENO's load forecast assumption in its economic analysis of the alternatives. Specifically, the load forecast reflected in ENO's transmission reliability analyses does not correctly account for the effect of ENO's 2 percent DSM goal[8]. Accordingly, the transmission reliability analyses reflect a load that is approximately 33 MW[9] too high by 2027. Advisors Witness Victor Prep discusses this inaccuracy in his Direct Testimony. In addition, ENO's load forecast assumption in its economic analysis is in disagreement with that reflected in the transmission reliability analyses. Namely, the economic analysis assumes that a 100 MW solar PV facility would produce 50 MW on peak. ENO's transmission reliability analyses assume that the same installed solar PV facility would produce 35 MW on peak. The combination of these two inconsistencies (15MW/100MW solar and 33 MW of DSM load reduction)

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[7] Such analyses have been designated as Critical Energy Infrastructure Information (CEII) by ENO, the details of which cannot be divulged publicly, and can only be shared with authorized Reviewing Representatives in accordance with the CEII Confidentiality Agreement in effect in this docket.

[8] The "Council's 2% Demand Side Management ("DSM") Goal is the incremental annual kWh savings (kWh reduction) from the utility's DSM programs will be increased each year by an amount equal to 0.2% of annual kWh sales, until the incremental annual kWh reduction from DSM programs reaches an amount equal to 2.0% of annual kWh sales.

[9] See ENO response to ADV 13-1.

could represent 63 MW total in the peak demand modeled in ENO's transmission reliability analyses. Further, ENO's economic analysis includes 300 MW of wind energy. The transmission reliability analyses do not reflect any capacity on peak for wind energy.

Q. WHAT EFFECT DO ENO'S INCONSISTENCIES HAVE ON THE TRANSMISSION ANALYSES YOU HAVE REVIEWED?

A. These conflicting input assumptions indicate to me that as modeled by ENO, the transmission reliability analyses reflect a load condition that inaccurately increases the stress level on ENO's transmission lines in the event of a transmission contingency over what would otherwise result had ENO properly accounted for the DSM goal in the load forecast reflected in its transmission reliability analysis model. Advisor Witness Prep discusses this inconsistency in his Direct Testimony. In addition, ENO's assumed capacity value for solar PV in the transmission reliability analyses is lower than that reflected in ENO's economic analysis, which again would also increase the stress on ENO's transmission lines in the event of a transmission contingency. Though the effect of these inconsistencies on the study results has not been determined, to be assured of the results, the accuracy of ENO's current input assumptions should be verified or such assumptions should be corrected to be assured that the results of the transmission reliability analyses are valid.

Q. CAN YOU PLEASE DESCRIBE ENTERGY'S TRANSMISSION ANALYSES?

A. In support of ENO's Supplemental Application, Entergy performed transmission reliability analyses for 2019, 2022, 2024 and 2027 study years, to identify thermal and voltage transmission reliability violations that would result under ENO's summer peak demand conditions from the occurrence of NERC Category P2.3 and P6 contingency events, both with and without the inclusion of a new ENO generating resource sited at Michoud. Three alternative cases with several variations in assumptions were analyzed:

> **Transmission Alternative:** three cases were provided by ENO: No NOPS; No NOPS but with a 200 MW solar generating facility at Michoud and a 2 percent demand-side management ("DSM") goal; No NOPS with a 2 percent DSM goal.

> **RICE Alternative**: Two cases were provided by ENO: NOPS modeled at 128 MW; NOPS modeled at 128 MW with a 100 MW solar facility at Michoud and a 2 percent DSM goal.

> **CT Alternative:** Two cases were provided by ENO: NOPS modeled at 226 MW; NOPS modeled at 226 MW with a 100 MW solar facility at Michoud and a 2 percent DSM goal.

Entergy's transmission reliability analyses reflect ENO's updated load forecast, a regional transmission topology which reflects all approved 2016 MISO Transmission Expansion Plan ("MTEP16") Appendix A[10] and MTEP17 Target Appendix A transmission projects throughout the MISO region. All solar resources are assumed to be interconnected at Michoud, and assumed to be dispatched at 35 percent of maximum capacity on peak. Entergy's 2024 and 2027 transmission analyses also assume the operation of a new 350 MW two-unit combustion turbine generation facility installed at the Washington Energy Center which is interconnected to EMI's Bogalusa substation.

Again, ENO's transmission reliability analyses performed in support of its Supplemental Application have been designated as Critical Energy Infrastructure Information (CEII) by ENO, the details of which cannot be divulged publicly, and can only be shared with

[10] Appendix A projects are those approved by for constructed by MISO's Board of Directors (BOD"); Target Appendix A projects are projects that are pending MISOP BOD approval for construction.

appropriate Reviewing Representatives in accordance with the CEII Confidentiality Agreement in effect in this docket.

Q. WHAT ARE YOUR OBSERVATIONS FROM YOUR REVIEW OF ENTERGY'S TRANSMISSION RELIABILITY ANALYSES?

A. Table 1 displays the results of ENO's transmission reliability analyses presented in ENO's Supplemental Application for each of the reference alternatives which exclude the solar PV and DSM assumptions. Results are shown for 2019, 2022, 2024, and 2027:

TABLE 1
SUPPLEMENTAL TRANSMISSION RELIABILITY ANALYSES
UPDATED LOAD FORECAST/ NO SOLAR/ NO DSM

2019 Transmission Reliability Analyses Results

Contingency	Transmission Alternative	RICE Alternative	CT Alternative
NERC - P2.3 Single	4 lines overloaded	4 lines overloaded	2 lines overloaded
NERC - P6 Double (NERC Requirement for Transmission Reliability)	9 lines overloaded. Cascading line trips. System Voltage Collapse. (Approx. 50,000 customers out of service)	2 lines overloaded Can be mitigated with 50 MW load shed	No reliability constraints
Transmission Upgrades Needed	$57.2 million by 2021	-	-

2022 Transmission Reliability Analyses Results

Contingency	Transmission Alternative	RICE Alternative	CT Alternative
NERC - P2.3 Single	2 slight overloads	No case run	No reliability constraints
NERC - P6 Double (NERC Requirement for Transmission Reliability)	9 lines overloaded. Cascading line trips. System Voltage Collapse. (Approx. 50,000 customers out of service)	No case run	No reliability constraints
Transmission Upgrades Needed	-	-	-

2024 Transmission Reliability Analyses Results

Contingency	Transmission Alternative	RICE Alternative	CT Alternative
NERC - P2.3 Single	2 lines slightly overloaded	No overloaded lines	No reliability constraints
NERC - P6 Double (NERC Requirement for Transmission Reliability)	9 lines overloaded. Cascading Outages. System Voltage collapse. (Approx. 50,000 customers out of service)	No overloaded lines	No reliability constraints
Transmission Upgrades Needed	-	-	-

2027 Transmission Reliability Analyses Results

Contingency	Transmission Alternative	RICE Alternative	CT Alternative
NERC - P2.3 Single	2 lines overloaded	2 lines slightly overloaded	No reliability constraints
NERC - P6 Double (NERC Requirement for Transmission Reliability)	9 lines overloaded. Cascading Outages. System Voltage collapse. (Approx. 50,000 customers out of service)	No overloaded lines	No reliability constraints
Transmission Upgrades Needed	$100,000 by 2027	$23.18 million by 2027	-

The above study results show that each of the alternatives would mitigate ENO's transmission reliability issues. Both the Transmission Alternative and RICE Alternative would require significant transmission upgrades to fully mitigate the reliability issues resulting from ENO's modeled P6 contingency. In addition, the RICE Alternative would require load shedding 50 MW of customer load in 2019 to achieve full mitigation. ENO has not provided any specific information on the number or location of ENO customers that would be interrupted in order to mitigate the P6 contingency. I note that Air Products and Chemicals, Inc. ("APC") has an agreement with ENO which allows ENO to interrupt 16 - 20 MW of APC load at ENO's discretion during ENO's four-month peak load period. This could potentially be utilized by ENO to partially mitigate the P6 contingency. I assume in this case that in addition ENO would interrupt approximately 30 MW of its firm customer load to fully mitigate the P6 contingency. ENO has not provided any information of the estimated duration of such customer interruptions. I estimate that such load shedding would result in interruptions to 6,000 - 10,000 ENO customers, depending upon ENO's curtailment of service to APC.

The CT Alternative would fully mitigate ENO's reliability issues without the need for any transmission upgrades. However, each alternative presents operational risks, which must be considered for a comprehensive comparison of each of the alternatives. I discuss these risk factors in detail later in my testimony.

Table 2 displays the results of ENO's transmission reliability analyses presented in ENO's Supplemental Application for each of the alternatives assuming ENO's solar PV and DSM assumptions. Results are shown for 2019, 2022, 2024, and 2027:

TABLE 2
SUPPLEMENTAL TRANSMISSION RELIABILITY ANALYSES
UPDATED LOAD FORECAST/ SOLAR/ DSM

2019 Transmission Reliability Analyses Results

Contingency	**Transmission Alternative / 2% DSM**	**Transmission Alternative 100MW / 100 MW / 2% DSM**	**RICE Alternative 100MW / 2% DSM**	**CT Alternative 100 MW / 2% DSM**
NERC - P2.3 Single	4 lines overloaded	4 lines overloaded	4 lines overloaded	2 lines slightly overloaded
NERC - P6 Double (NERC Requirement for Transmission Reliability)	9 lines overloaded. Cascading line trips. System Voltage Collapse. (Approx. 50,000 customers out of service)	8 lines overloaded. Cascading line trips. System Voltage Collapse. (Approx. 50,000 customers out of service)	1 line overloaded	No reliability constraints
Transmission Upgrades Needed	$44.3 million by 2021	-	Can be mitigated with 25 MW load shed	-

2022 Transmission Reliability Analyses Results

Contingency	**Transmission Alternative / 2% DSM**	**Transmission Alternative 100MW / 100 MW / 2% DSM**	**RICE Alternative 100MW / 2% DSM**	**CT Alternative 100 MW / 2% DSM**
NERC - P2.3 Single	No case run	No case run	No case run	No reliability constraints
NERC - P6 Double (NERC Requirement for Transmission Reliability)	No case run	No case run	No case run	No reliability constraints
Transmission Upgrades Needed	-	-	-	-

(cont.) 2024 Transmission Reliability Analyses Results

Contingency	Transmission Alternative / 2% DSM	Transmission Alternative 100MW / 100 MW / 2% DSM	RICE Alternative 100MW / 2% DSM	CT Alternative 100 MW / 2% DSM
NERC - P2.3 Single	2 lines slightly overloaded	No overloaded lines	No overloaded lines	No reliability constraints
NERC - P6 Double (NERC Requirement for Transmission Reliability)	9 lines overloaded. Cascading line trips. System Voltage Collapse. (Approx. 50,000 customers out of service)	1 overloaded line Mitigated with 25 MW load shed	No overloaded lines	No reliability constraints
Transmission Upgrades Needed	-	-	-	-

2027 Transmission Reliability Analyses Results

Contingency	Transmission Alternative / 2% DSM	Transmission Alternative 100MW / 100 MW / 2% DSM	RICE Alternative 100MW / 2% DSM	CT Alternative 100 MW / 2% DSM
NERC - P2.3 Single	3 lines overloaded	2 lines overloaded	No overloaded lines	No reliability constraints
NERC - P6 Double (NERC Requirement for Transmission Reliability)	9 lines overloaded. Cascading line trips. System Voltage Collapse. (Approx. 50,000 customers out of service)	1 overloaded line Mitigated with 20 MW load shed	No overloaded lines	No reliability constraints
Transmission Upgrades Needed	-	$23.18 million by 2027	-	-

Similar to the results observed in Table 1, the Table 2 study results, including ENO's solar PV and 2 percent DSM goal assumptions, show that each of the alternatives would also mitigate ENO's transmission reliability issues. However, the Transmission Alternative with 100 MW solar PV and 2 percent DSM would need significant transmission upgrades, or would require load shedding 25 MW of customer load in 2024, and 20 MW of customer load in 2027 to fully mitigate the reliability issues. APC's agreement with ENO could potentially be utilized by ENO to partially mitigate the P6 contingency. I assume in this case that in addition ENO would interrupt approximately 5

- 9 MW of its firm customer load to fully mitigate the P6 contingency in 2019. I estimate that such load shedding would result in interruptions to 1,000 – 1,800 ENO customers, depending upon ENO's curtailment of service to APC. APC's agreement with ENO could potentially be utilized by ENO to fully mitigate the P6 contingency in 2027 without needing to interrupt service to any ENO firm load customers.

The RICE Alternative with 100 MW of solar PV and 2 percent DSM would require load shedding of 25 MW of customer load in 2019 to achieve mitigation. which could be mitigated by shedding 25 MW of ENO load using both the APC agreement and by disrupting service to 1,000 – 1,800 ENO customers.

The CT Alternative with 100 MW of solar PV and 2 percent DSM would fully mitigate ENO's reliability issues without any transmission upgrades. However, each of these alternatives present operational risks, which must be considered for a comprehensive comparison of each of the alternatives, which I discuss later in my testimony.

Q. IS IT YOUR OPINION THAT AS A RESULT OF RETIRING ENO'S MICHOUD UNITS 2 AND 3 ENO'S SYSTEM IS PRESENTLY AT RISK OF TRANSMISSION RELIABILITY ISSUES?

A. Yes. ENO's transmission system topology is essentially unchanged since the retirement of the Michoud generating units in 2016. I believe that without a local generating resource, and/or needed transmission upgrades, ENO's system is presently at risk of transmission reliability issues. My evaluation of the results of ENO's transmission reliability analysis of the Transmission Alternative for 2019 the P6 contingency indicates that ENO's transmission system would experience cascading outages leading to a voltage collapse of ENO's 115 kV system placing approximately 49,000 customers out of service. This 2019 analysis is a good proxy for ENO's system performance in 2017-2018.

Though the occurrence of a P6 contingency is a low probability event, the consequences to ENO's customers of such an event are not! As ENO's transmission reliability analyses for the 2019 study year performed in support of its Application clearly show, a P6 contingency would result in cascading outages leading to a voltage collapse of ENO's 115 kV network, ultimate placing approximately 49,000 ENO customers out of service. I would reasonably expect the same result for such a contingency in 2017 or 2018 were it to occur.

Q. **IS THE PROPOSED LOCATION FOR LOCAL GENERATION BENEFICIAL FROM A TRANSMISSION RELIABILITY PERSPECTIVE?**

A. Yes. ENO's system is located at the extreme eastern end of the DSG load pocket. Considering ENO's transmission system topology, the proposed location of local generation at ENO's former Michoud site would be beneficial from a transmission reliability perspective, as it would allow ENO to continue to reliably serve its customer load during certain transmission system contingencies, such as the specific NERC P2.3 and P6 contingencies modeled in Entergy's transmission reliability analyses. Locating local generation at Michoud would have a direct transmission path to eliminate the transmission overloads that would result in the event of the P6 contingency and support ENO's ability to continue to reliably serve its customers. The CT Alternative would accomplish this without the need for any transmission upgrades. The RICE Alternative would also accomplish this, assuming ENO's identified transmission upgrades are completed.

From my review of the results of such analyses, it is my opinion that alternate location of local generation - such as in the western portion of ENO's system - would not support ENO's ability to reliably serve its load and mitigate transmission reliability violations in the event of such contingencies, as the occurrence of a P6 contingency would sever the interface between ENO's 115 kV and 230 kV networks thereby eliminating the transmission path needed to mitigate it, and as a result, such generation would not support ENO's ability to continue to serve its customer loads.

Q. DO YOU BELIEVE THAT DOING NOTHING LONG-TERM WOULD BE AN ACCEPTABLE COURSE OF ACTION FOR ENO?

A. No. Based upon my review of the Transmission Alternative case which shows the results of not accomplishing ENO's identified transmission upgrades, assuming a new local generating resource is not installed, the analysis clearly indicates that, because of ENO's modeled P6 contingency, ENO's 115 kV system would suffer a voltage collapse placing a potentially excessive number of ENO customers out of service, both in the near-term and long-term. The specific nature of the P6 contingency modeled by ENO is such that the duration of the outage could be several days or more, depending on the availability of the specific replacement equipment needed to restore service, as well as the logistics involved in getting the needed equipment into New Orleans for installation, and the effort required to get such equipment installed. Accordingly, a "do nothing" course of action is totally unacceptable in my opinion.

Q. DO YOU HAVE ANY CONCERNS WITH ENO'S TRANSMISSION UPGRADE PROJECTS NEEDED TO MITIGATE TRANSMISSION RELIABILITY VIOLATIONS?

A. Yes, I do. As noted earlier in my testimony, five of the seven alternatives ENO has analyzed in its transmission reliability analyses require transmission upgrade projects[11] to fully mitigate the modeled P6 contingency transmission reliability violations. Only the CT Alternative, and RICE Alternative including 100 MW of solar and assuming 2 percent DSM would avoid the need to construct any transmission upgrades. Accordingly, excepting the CT Alternative, the feasibility of each other alternative is dependent in part upon whether or not such transmission upgrade projects can be constructed, and if they can be constructed prior to their respective "need by" dates. This raises serious concerns. Concerning transmission constructability issues, in his Supplemental and Amending Direct Testimony, at page 16, line 20 – page 127, line5, ENO witness Charles Long states:

"Secondly, as stated in my Direct Testimony, there are significant constructability issues in the New Orleans area with respect to transmission. I have considerable experience with *planning and constructing transmission in the New Orleans area, including assisting in the restoration of the storm-damaged transmission in the greater New Orleans area. In my experience, the soil conditions, obstructions, and environmental challenges tend to increase the cost of construction substantially and necessitate expensive wetlands damage mitigation following the construction of a transmission line.*

[11] Each of these six alternatives require different transmission upgrade requirements.

There are also right-of-way issues, as well as many above-ground and below-ground infrastructure (such as pipelines) which make it very difficult to construction transmission facilities.

In example of the problems associated with constructing transmission in the New Orleans area, in response to Advisors 12-1, ENO states:

"For example, severe constructability challenges have delayed the projected in-service date of the Southeast Louisiana Coastal Improvement Plan Phase 3 project by ***five years past the anticipated in-service date****. The original in-service date has slipped from Summer 2012 to early 2018, and the expected cost (including substation work at each end that was already completed several years ago) has increased significantly. Needless to say, the construction of the transmission lines in south Louisiana is extremely challenging. The Company assumes that given enough time and money, the transmission upgrades referenced in this case can eventually be constructed well after the time when they are needed.; but the highlighted constructability issues illustrate the point that these upgrades can take a very long time, and become far more costly than the Company has assumed in this case based upon generic cost assumptions."*

Regarding difficulties taking transmission outages in DSG for needed maintenance, ENO witness Charles Long states at page 6-7:

"In the first half of this year alone, outages involving a 115 kV transmission segment, a 230/115 kV auto-transformer, five 230 kV transmission lines and two 500 kV transmission lines were denied (by MISO) because of reliability constraints that could not be mitigated without risking electric service to the Company's customers."

I would expect ENO to face similar difficulties in taking its transmission lines out of service for the accomplishment of the needed upgrades, as ENO Witness Charles Long has asserted[12], especially considering the duration of outages that would be required to replace transmission structures in support of re-conductoring, and the time required to accomplish re-conductoring work. Regarding the time to construct ENO's transmission

[12] See ENO response to ADV 13-1.

upgrades required to be completed in support of the Transmission Alternative, in its response to Advisors 12-3c., ENO states:

"To begin with, given the constructability issues identified in this proceeding, it is doubtful that all of the projects at issue can be completed before the 2022 time period – thus, constructing the projects would only make sense if they are the preferred long-term solution, which they are not."

ENO amplifies their concerns with the Transmission Alternative in its response to Advisors 12-4a. which states:

"The timing of transmission upgrades, however, is far less predictable, and the Company states that the earliest it could likely get any of the lines in service would be mid 2021. But to be clear, all of the 5 upgrades would be needed if NOPS is not constructed. The Company could not construct all 5 upgrades at once given the operational conditions involved with scheduling the transmission outages and other constructability issues mentioned in the Testimony of Charles W. Long at pg. 16-17, and the Company's response to Advisors 12-1."

Further, ENO's response to Advisors 12-4b. states:

"The Company has not performed the detailed design and scoping work necessary to provide the timetable required to construct the transmission plant identified in the referenced Table 1. Such design and scoping work will involve a thorough inspection of the transmission structures, including those of lattice towers, which is generally a lengthy process. A determination will be made about the possibility of employing a high temperature low-sag conductor and, subsequently, whether the transmission structures would need to be replaced in order to accommodate the new conductors. The design and scoping work is very likely to require field crews to gather data and an engineering model that will be used to analyze the gathered data. In other words, this process will take an extraordinary amount of time and resources to accomplish; and the Company has not expended those resources on an option that it considers to be far inferior to the mitigation measure that is currently in its long-term plan, which is to replace a portion of the retired Michoud capacity with a NOPS alternative."

Based upon ENO's above statements, a large number of unknowns exist, and in its Supplemental Application, ENO has not clearly demonstrated that its proposed projects are feasible and constructible on an accelerated basis. Based upon my personal experience with transmission projects throughout my career in the electric utility industry, and knowledge of ENO's transmission system gained over the past twenty-three years, it is my opinion that prior to reliance upon the Transmission Alternative by the Council ENO should be directed to file with the Council a demonstration that its proposed projects are feasible and constructible on an accelerated basis.

VI. <u>INTERVENOR'S WITNESS TESTIMONY</u>

Q. DO YOU AGREE WITH ALLIANCE WITNESS PATRICK LUCKOW'S ASSERTION THAT THERE ARE OTHER TRANSMISSION PROJECTS THAT WILL INFLUENCE THE NEED FOR NOPS?

A. In his Direct Testimony at page 23 lines 12-17, Mr. Luckow states:

"Yes. Specifically, the Southeast LA Economic Project (DSG Alternative 6) ("Project"), which is approved as part of MISO 2016 MTEP, will provide for 650 MW of additional import capability into the DSG load pocket, and would be in service by 2022. This transmission improvement is incremental to the resources considered in Case 2 of ENO's supplemental analysis. It would afford the ENO service area access to additional resources in the MISO South region."

I disagree with Mr. Luckow's statement cited above. Though this project will provide 650 MW of additional import capability into the DSG load pocket, and may afford ENO access to additional resources in the MISO region, from my evaluation of Entergy's transmission reliability analyses, such incremental transmission capability would not support the delivery of imported power to support ENO's system in the event of the occurrence of the NERC Category P6 event modeled in ENO.

Q. DO YOU AGREE WITH INTERVENOR'S WITNESS ROBERT FAGAN'S TESTIMONY AT PAGE 9 THAT EXISTING GENERATION IN THE DSG LOAD POCKET CAN BE UTILIZED BY ENO TO REDUCE LOCAL LOADING ON CERTAIN TRANSMISSION CIRCUITS?

A. I disagree with Mr. Fagan's assertion. With the retirement of Michoud Units 2 and 3, and without a local generating resource in ENO's system, ENO's power supply is limited to external sources. ENO has transmission paths to three generating plants: Waterford, Nine Mile and Little Gypsy. These plants provide power to southeastern Louisiana including the large loads in the ELL's Industrial Corridor to the west of the New Orleans area. Accordingly, they have been dispatched at a higher level having to supply ENO's load requirements than might otherwise be required. None of these generating units are dispatched solely to serve ENO's load requirements. ELL's Waterford Nuclear Plant is dispatched at full load on a continuous basis as would be expected for a nuclear unit. ELL's Nine Mile plant operates at a high capacity factor. It's important to consider that ENO is served predominantly by the transmission path from Nine Mile. To a lesser extent, ENO has a much more limited transmission path from Little Gypsy. Accordingly, there does not appear to me that adjusting external generation is a realistic alternative. In addition, ENO has reported the problems it has faced since its retirement of Michoud Units 2 and 3 in getting MISO's approval to remove transmission circuits from service for maintenance projects. MISO is responsible for dispatching all generation in its market, including MISO designated VLR units. I would assume that if MISO could adjust area generation as an alternative course of action to reduce ENO transmission circuit loading, it would have developed an operating guide for that express purpose, which it has not.

Q. DO YOU AGREE WITH INTERVENOR'S WITNESS ROBERT FAGAN'S TESTIMONY AT PAGE 7, THAT INCREMENTAL SOLAR PV IN NEW ORLEANS, THE DSG LOAD POCKET, OR THE REST OF LOUISIANA GENERALLY IMPROVES THE OVERALL RELIABILITY OF THE SYSTEM?

A. Though incremental solar PV outside ENO's footprint may provide some benefit to the DSG load pocket, or the rest of Louisiana in general, I do not believe that it would contribute to ENO's overall reliability or would mitigate the transmission overloads that can occur because of certain contingencies, such as the P6 contingency modeled by ENO. Incremental solar PV located in ENO's service territory would provide some support to ENO's reliability, but only if it is located where electrically required to mitigate transmission contingencies within ENO's system. In my judgement, dispersed solar PV in New Orleans would have minimal effect, if any, on resolving ENO's transmission reliability issues. In order to provide support to mitigate the P6 contingency modeled by ENO, solar PV capacity would have to be located at the eastern end of ENO's service area, ideally interconnected at Michoud. ENO states a similar concern in its response to Advisors 7-16b which states:

"…Moreover, in order to address NERC compliance in this case, solar would need to be located in a precise location (in or around the Michoud Facility), which is very unlikely."

ENO reiterates its opinion in its response to Advisors 7-16c:

"Ideally the generation would be concentrated very near the Michoud facility. This, even if solar were not intermittent and could be dispatched, it is extremely unlikely, given the

amount of land necessary for 100 or 200 MW of solar, that the majority of ENO's solar additions could be located around the Michoud facility."

I concur with ENO's concern in this regard. Assuming industry average land requirements for solar PV installations, a 100 MW solar PV facility would require 730 acres of available land. A 200 MW solar PV facility would require 1,460 acres of available land. Though such solar PV installations have been modeled by ENO, it has not been established that suitable land in the required acreages is available in close proximity to Michoud.

Further, such solar PV capacity would need to be interconnected with ENO's transmission system to mitigate a P6 contingency. As solar PV capacity can't be dispatched or ramped up, it would not be useable to power critical loads in the event of an islanding event or for restoration of service after a major system outage. I am also concerned with the intermittent nature of solar PV capacity, which depends on solar radiation to produce power. In the event of extended cloudy weather after a major storm event, solar output may likely be minimal at best. New Orleans experienced such weather conditions after Hurricane Gustav. Further, I would be concerned that large scale solar, as modeled in several of ENO's analyses, would be prone to wind damage from severe major storm events and hurricanes, and would be at significant risk of physical damage from airborne debris strikes during such storms, thus negating its ability to support storm restoration or support system reliability in general. Exhibit (PJM-5) provides examples of storm-driven wind, tornado, and flooding damage inflicted upon solar PV installations. Finally, solar PV connected to ENO's distribution or Behind-The-Meter ("BTM") installations would of necessity be disconnected from ENO's system in the event of a system collapse, as would occur from a P6 contingency event, or islanding situation which takes the system down. This is because in the event of such catastrophic events, all incoming distribution substation circuit breakers would be opened to protect ENO staff from electrocution hazards so that they can accomplish necessary repairs. ENO's primary distribution system will not be reenergized until all transmission repairs are completed and the transmission is re-energized without load. Repair and restoration of primary distribution lines would then be accomplished. As the final step in restoring the system to service, individual services to customer homes and businesses would then be repaired. Accordingly, such solar capacity will not have a connection to ENO's system until their primary distribution feeders are restored to service, and services lines are repaired. From my experience in service restoration, primary distribution feeders are restored to service one at a time after energizing the substation transformers. Therefore, distribution or BTM connected solar will not be able to provide any significant support to system restoration.

Q. PLEASE COMMENT ON INTERVENOR'S WITNESS ROBERT FAGAN'S TESTIMONY AT PAGE 27, THAT THE COMPLETION OF MISO MULTI VALUE PROJECTS ("MVP") WILL ALLOW FOR INCREASED PENETRATION OF WIND RESOURCES TO BE RELIABILITY INCORPORATED INTO THE ENTIRE MISO MARKET?

A. This is true in a broad general sense. However, all MISO MVPs were identified and planned long before the Entergy Operating Companies (including ENO) became members of MISO. Accordingly, such projects were not planned to deliver power to the MISO South region where ENO is located. All projects currently in MISO's MVP portfolio are located in the northern end of MISO's footprint in the MISO North region, weren't designed to, and will not, deliver such wind resources to ENO, owing to the fact that they are geographically remote from ENO. Mr. Fagan's assertion fails to consider that imports to and exports from power into/from MISO South are presently limited by a single North/South Ameren transmission interface which are limited both contractually and physically[13]. The Ameren Tie is heavily loaded. Mr. Fagan seems to assume that MISO's transmission system is a copper plate, which it is not. The transmission lines that would be required to deliver such wind resources to MISO South do not presently exist in the MISO's footprint, nor in the MTEP, and have not been planned. It is possible that at some distant time in the future, new MISO North – MISO South transmission interfaces will be developed to support delivery of such wind resources. However, imports of wind energy from MISO North into MISO South will not alleviate DSG's or ENO's transmission reliability issues.

Q. PLEASE COMMENT ON INTERVENOR'S WITNESS ROBERT FAGAN'S TESTIMONY AT PAGE 37, THAT ELL AND ENO HAVE NUMEROUS 115Kv AND 230kV REINFORCEMENT PROJECTS IN THE PIPELINE FOR RELIABILITY AND GENERATION INTERCONNECTION REASONS?

A. Virtually all of ELL's transmission projects included in MISO's MTEP17 have been designated Baseline Reliability Projects ("BRPs"). BRPs are Network Upgrades required to ensure that the MISO transmission system remains in compliance with applicable reliability standards adopted by NERC, the appropriate Regional Entities within the MISO region, and Local Transmission Owner planning criteria filed with and approved

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[13] The Ameren Tie transmission interface is contractually limited to a maximum flow of 1000 MW, and physically limited to 2,500 MW South to North flows and 3,000 MW North to South flows.

by FERC. BRPs include projects operating at 100 kV or above that are needed to maintain reliability while accommodating the ongoing needs of existing Transmission Customers. The project costs of BRPs are allocated to the MISO Transmission Pricing Zone ("TPZ") found to benefit from their construction. In the case of ELL, such BRPs are allocated solely to ELL's TPZ. ENO has its own dedicated TPZ and is not allocated any costs for such projects as it does not benefit from them. Other ELL transmission projects included in MTEP17 have been designated "Other" projects, which are cost allocated to the sponsoring Market Participant. In the case of ELL, such Other projects are designed to provide service to new large industrial loads (primarily in Entergy's WOTAB[14] region which encompasses south western Louisiana). Though such projects directly benefit ELL, they do little to nothing to alleviate ENO's transmission reliability problems.

Q. PLEASE COMMENT ON INTERVENOR'S WITNESS ELIZABETH STANTON'S TESTIMONY AT PAGE 26, THAT AT LEAST ONE TRANSMISSION PROJECT CURRENTLY UNDER DEVELOPMENT WOULD FACILITATE TRANSPORT OF WIND ENERGY INTO THE STATE OF LOUISIANA?

A. I believe that Ms. Stanton is referring to the Southern Cross HVDC Project. My review of the proposed line routing for this project indicates that this line would traverse the north-western border of Louisiana and Texas to extreme north-eastern Mississippi. The Project's western convertor station is proposed to be located close to Texas-Louisiana border in Desoto Parish, Louisiana. The project's eastern convertor station is proposed to

[14] West of the Atchafalaya Basin

be located in north eastern Mississippi near the Alabama border. Both terminal ends of this project are remote from ENO's system. HVDC transmission lines are express lines which transport bulk power bi-directionally between their convertor stations, and do not have intermediate convertor stations for the delivery of power to AC transmission grids. The project does not include any intermediate convertor stations in Louisiana. Accordingly, though this project may have benefit to Texas, north eastern Mississippi, Alabama, etc. if actually developed, it will not deliver Texas wind resources to Louisiana, and ENO in particular. Likewise, even if ever developed, this project would do nothing to alleviate ENO's transmission reliability problems.

Q. PLEASE COMMENT ON INTERVENOR'S WITNESS ELIZABETH STANTON'S TESTIMONY AT PAGE 48, THAT NEITHER BUILDING NOPS NOR TRANSMISSION UPGRADES WILL LEAD TO MORE ELECTRICITY BEING CONSISTENTLY DELIVERED TO CUSTOMERS IF THE DISTRIBUTION SYSTEM IS BROKEN?

A. Though technically this is a correct statement, Ms. Stanton fails to understand that ENO's proposal to construct NOPS has nothing to do with ENO's distribution system reliability. Both transmission and distribution are necessary to deliver power from generating resources to ultimate customers. The transmission system delivers power at bulk to distribution substations for conversion from transmission voltage to primary distribution voltage for ultimate delivery to customers throughout the affected distribution system. If the transmission system is incapable, as a result of transmission reliability issues, of delivering power to down-stream distribution stations for ultimate delivery to customers, customers will be without service. That is why it is important to maintain the transmission system's ability to reliably deliver power at bulk. All things being equal, the addition of local generation, such as NOPS, and/or accomplishment of transmission upgrades should insure the reliability of the transmission system to fulfill its mission. Distribution system reliability is a separate and discrete matter. Though maintaining reliable distribution system performance is also very important for overall operation of an electric system, it has no effect upon ENO's transmission reliability. I note that ENO's distribution system reliability is currently being investigated by the Council in Council Docket No. UD-17-04.

Q. DO YOU BELIEVE THAT IT WOULD BE BENEFICIAL FOR NOPS TO HAVE BLACK START CAPABILITY?

A. Yes. In his Direct Testimony at page 13, the answer to Q17, ENO witness Charles Long states:

"NOPS also adds a local source of active or "real" power in the DSG load pocket with the ability to start quickly. This can aid in shortening the time to restore service to customers after large scale events such as hurricanes or other natural disasters. For example, if the transmission system experiences extensive damage during a hurricane, which has occurred in the past in the New Orleans area, the ability to import power across the transmission lines may be impaired for many days due to transmission system damage. In such a scenario, local generation units make it possible to locally supply power through a smaller number of relatively short transmission lines which can be repaired more quickly. A unit like the proposed NOPS provides a "starting point" for restoration and allows restorations to occur more quickly than would be possible relying solely on transmission facilities."

I fully agree with Mr. Long's assertion that local generation would provide a "starting point" for restoration of service to ENO's customers in the event ENO's ability to import power is impaired due to transmission system damage. However, ENO has not committed to install black start capacity with the CT Alternative, and has indicated in their response to Advisors 4-4 that:

"The Company has not performed studies to investigate the ability to start NOPS from other generating resources in DSG, the current black start plan includes a cranking path from Waterford through the Michoud substation."

I have reviewed Entergy's 2016 System Restoration & Blackstart Plan[15] ("Plan") covering the Louisiana South Area which identifies a specific transmission path that could be used for black starting NOPS, including a detailed transmission switching plan. I agree that Entergy's identified transmission path could be used to black start local generation, and from my review this path would not be affected by the occurrence of the NERC Category P2.3, and P6 events modeled in Entergy's additional transmission analyses. However, in the event that any of the transmission lines that make up this path suffered outages or were out of service for maintenance or repairs, local generation would no longer have any black start capability. Considering that ENO's identified cranking path for Waterford Nuclear to Michoud is approximately forty miles long, relying on such a long path would be risky. ENO witness Charles Long further asserts in his Direct Testimony at page 13, the answer to Q17:

"A local generator, such as NOPS, will also greatly aid in maintaining the integrity of the electric grid in the event a storm severs the electric grid a manner that creates an electrical island."

In the event that ENO's "electrical grid" is islanded, Entergy's identified transmission path may not be available for black starting local generation. Accordingly, though I agree that while transmission can be used for black-start service, it may likely not be available when needed. For this reason, I believe that the inclusion of on-site dedicated black start capacity for local generation would provide a dependable local resource that would minimize the inherent risk from relying solely on transmission for black-starting. I

[15] ENO's Plan provided in response to Advisors 4-4 consists of Critical Energy Infrastructure Information (CEII).

am also concerned that Entergy has not yet performed any studies demonstrating the feasibility of black starting the CT Alternative unit with other generating resources in DSG. On the other hand, ENO's RICE Alternative has black-start capability built-in and would not have to rely on the availability of a transmission path for black starting. I believe that black start capability is a very important consideration when comparatively evaluating the two generating alternatives presented by ENO in this docket.

Q. DO YOU AGREE WITH INTERVENOR'S WITNESS LUCKOW'S ASSERTION[16] THAT OTHER UNITS IN THE REGION, BOTH INSIDE AND OUTSIDE THE LOAD POCKET CAN PROVIDE BLACK START CAPACITY FOR NOPS BECAUSE THE TRANSMISSION CONNECTIONS INTO THE DSG LOAD POCKET ARE BOTH NUMEROUS AND OF AMPLE CAPACITY?

A. No, I do not. Mr. Luckow makes a very broad assumption. Having numerous transmission connections of ample capacity into the DSG load pocket does not in itself guarantee that power delivered into DSG is deliverable to ENO. Further, reliance on external units must be analyzed to determine the feasibility of using them for black start service, specific transmission paths must be identified and detailed transmission switching plans must be developed before external resources or transmission can be relied upon for black-starting NOPS. Such studies have not been performed by Entergy to my knowledge. Additionally, specific feasible transmission paths would need to be identified through ENO's system that could deliver external sources of generation to NOPS before such reliance could be considered. The risk of a transmission outage in DSG external to ENO, or a transmission outage within ENO's system could negate the

[16] See Direct Testimony of Patrick W. Luckow at page 23, lines 22-23.

ability of transmission system to deliver power to ENO for black-start service, irrespective of the number and capacity of transmission connections into DSG. Having local generation, such as NOPS, would provide a dependable source of black starting power and avoid the risks of transmission failure. I believe that this is especially important given that ENO's system exists in an extreme weather event region.

Q. DO YOU AGREE WITH INTERVENORS' WITNESS PETER LANZALOTTA'S TESTIMONY AT PAGE 9, ASSERTING THAT THE COMPANY DID NOT GIVE SERIOUS CONSIDERATION TO AN UNDERGROUND TRANSMISSION OPTION?

A. I don't believe that ENO needed to give serious consideration to an underground transmission option. Underground 115 kV transmission is typically five to ten times more expensive than overhead transmission. I strongly doubt that this level of investment in underground transmission would make economic sense to ENO's ratepayers, especially when a large portion of ENO's transmission upgrade projects are limited to reconductoring existing overhead transmission lines on the existing transmission structures at a much lower cost than the costs necessary to construct underground transmission. Properly designed, constructed and maintained overhead transmission lines provide long term reliable service. Properly maintained overhead transmission lines have an average life expectancy of approximately seventy five years. In comparison, underground transmission lines have an average life expectancy of 30 - 40 years. Underground transmission is not a panacea. Damage to underground transmission lines may take several weeks or more to repair. Pinpointing underground transmission cable faults is time consuming and difficult. Damage to overhead transmission is relatively easy to locate and repairs can typically be accomplished in relatively short periods of time. Construction of underground transmission is a difficult expensive undertaking, as underground transmission cable is usually placed in duct. In example, a 230 kV underground transmission cable would be placed in a continuous trench sized to accept a 3-ft. wide by 7 ft. deep duct bank. Underground transmission cable runs are limited to 2,000 – 2,500 ft. Accordingly, accessible splicing vaults would have to be installed at that interval over the total length of the cable run. Installation of underground transmission in New Orleans would be very disruptive to local citizens and businesses. Underground 230 kV transmission costs between 10 – 15 times more than overhead construction. Simply put, it would be price prohibitive. It is also unlikely that a suitable right-of-way could be identified for the construction of such a project. Land would also have to be procured for transition stations at each terminus. From my long-term experience in New Orleans utility matters, I firmly believe that the number of existing underground obstructions would make the construction of underground transmission infeasible. I would also be very concerned with the reliability of underground transmission in New Orleans as a result of the ever-present risk of water intrusion, as New Orleans elevation is below mean sea level. ENO has experienced extensive water intrusion problems over the years with its underground distribution system in New Orleans East. For all of these reasons, I discard underground transmission as a reasonable alternative for ENO.

Q. PLEASE COMMENT ON INTERVENOR'S WITNESS PETER LANZALOTTA'S TESTIMONY AT PAGE 11, CONCERNING ENO'S USE OF A STATIC VAR COMPENSATOR IN LIEU OF NOPS FOR SYSTEM VOLTAGE CONTROL?

A. Though I don't disagree with Mr. Lanzalotta that a Static Var Compensator ("SVC") could be used to provide dynamic reactive support for ENO's system during normal system operations, in my opinion it would be of negligible benefit in the event of ENO's modeled P6 contingency. The P6 contingency results in an immediate severe thermal overload of several lines which import power to ENO's system. These lines are tripped by ENO's high speed relaying. Upon this action, and as a result of the specific nature of the P6 contingency, ENO's ability to serve load would be severely diminished. Follow-on Zone 3 clearing of thermally overloads on down-stream transmission lines would continue to reduce the system's ability to supply real power to meet load requirements. As a consequence of not having an adequate power supply, the system collapses. The only way to mitigate such a result would be to have a dynamic resource such as a generator to provide power to alleviate the thermal overloads and supply the reactive requirements needed to avoid system collapse. Both real power and reactive power are needed to mitigate such a P6 event. SVC's do not produce real power (MW) and would likely not eliminate the cascading outages observed by ENO in its transmission reliability analyses.

IV. <u>CONCLUSIONS</u>

Q. BASED UPON YOUR EVALUATION OF ENO'S SUPPLEMENTAL APPLICATION AND SUPPORTING TESTIMONY, INTERVENOR'S TESTIMONY, AND THE DISCOVERY RESPONSES FILED IN THIS DOCKET, WHAT ARE YOUR CONCLUSIONS?

A. From my evaluations, it is my opinion that ENO's retirement of Michoud Units 2 and 3 in 2016 has placed ENO's system at risk for severe transmission thermal overloads resulting in cascading transmission outages ultimately leading to a voltage collapse of ENO's 115 kV network, in the event of the occurrence of the NERC Category P6 double contingency modeled in Entergy's transmission reliability analyses. Though this is a low probability event, the consequences of such a contingency to ENO's customers are not! As this event would result in placing approximately 49,000 ENO customers out of service, the current situation represents a significant risk to New Orleans. Owing to the specific nature of this contingency, equipment replacement and repairs could take several days or more to complete. Without a local generating source located in New Orleans, ENO's system has been reduced to having to import all of its power supply over significantly constrained transmission lines. In the event that local generation is not constructed, and transmission upgrade projects are not accomplished, ENO's system will continue to face potentially excessive risks of catastrophic outages. Accordingly, the "do nothing" alternative presently does not, and in the future, will not support reliable operation of ENO's system.

When weighing the benefits of each alternative presented in ENO's Supplemental Application, the inherent risks of each alternative must be considered in order to determine the best alternative. I discuss the benefits and risk of each alternative below.

CT Alternative and RICE Alternative

ENO has presented two generation alternatives in its Supplemental Application for the Council's consideration: 1) construction of a single simple cycle 226 MW combustion turbine generating facility (the CT Alternative), and 2) construction of a 126 MW reciprocating internal combustion engine generating facility consisting of seven units (the RICE Alternative). Owing to transmission limitations throughout the DSG region, I would expect that both of these generating facilities would be designated as VLR units by MISO, and would be dispatched during high load periods to support the reliability of

ENO's system, as well as the DSG transmission grid. Both of these generating facilities would provide a valuable source of dynamic voltage support, and would support ENO's restoration of service after a major system outage resulting from a major contingency, or major storm event, such as a hurricane.

Based upon my evaluation of ENO's transmission reliability analyses, I conclude that the CT Alternative would fully mitigate ENO's transmission reliability issues without the need to accomplish any transmission upgrade projects. Likewise, the RICE Alternative, would mitigate ENO's transmission reliability issues, but only if $23 million in transmission upgrades are accomplished by 2027. Further, ENO would additionally need to shed 50 MW of customer load in 2019 in the event of a NERC Category P6 double contingency event.

Black Start Capability: Owing to the risk of major system outages as a result of a critical contingency in ENO's system, or islanding situation which ENO experienced as a result of Hurricane Gustav, having black-start capability in support of continuing to have the ability to supply ENO's critical loads is a very important factor in comparing ENO's proposed generation alternatives. Further, it is my belief that local generation could potentially be utilized as an adjunct source of power to the S&WB's Carrolton pumping plant, if required, to insure that the City continues to be pumped out in the event of major flooding, as has occurred numerous times. In order to insure that local generation can be operated after a major system outage, it is critical that the generator(s) have black-start capability. Both the CT Alternative and RICE Alternative would have a form of black-start capability. However, black-starting would be accomplished by different means. The CT Alternative would rely on a transmission path from the Waterford Nuclear Plant to provide a source of power for black-starting the unit. This is the same transmission path that ENO designated for black-starting Michoud. The RICE Alternative can be black-started on its own without any need for an external source of power. In comparing the two black-start alternatives, it's my opinion that the RICE Alternative's self-contained black-starting capability is far superior than the CT Alternative's approach, as the CT Alternative's reliance on a distant source of power utilizing a lengthy transmission path presents potentially excessive risk, as the transmission lines required to deliver power for black-starting may be out of service as a result of a major transmission system contingency or an islanding situation, and would not be available to black-start the CT. To place both alternatives on an equal footing, the CT would require black-start capability on site, which ENO has indicated would be a very expensive undertaking, and as such ENO has not included it in its proposal.

Transmission Alternative

ENO has indicated that in that event local generation is not constructed, significant transmission upgrades estimated to cost $57.3 million would be required to mitigate ENO's transmission reliability issues. I agree with ENO's transmission reliability analysis results on face value. However, I question ENO's results stemming from its conflicting input assumptions which indicate to me that, as modeled by ENO, the transmission reliability analyses reflect a load condition that increases the stress on ENO's transmission lines in the event of a transmission contingency, than would otherwise result had ENO properly accounted for the DSM goal in the load forecast reflected in its transmission reliability analysis model. Advisor Witness Prep discusses this inconsistency in his Direct Testimony. In addition, ENO's assumed capacity value for solar PV in the transmission reliability analyses is lower than that reflected in ENO's economic analysis, which would also increase the stress on ENO's transmission lines in the event of a transmission contingency. Though the effect of these inconsistencies on the study results has not been determined, to be assured of the results, the accuracy of ENO's current input assumptions should be verified or such assumptions should be corrected to be assured that the results of the transmission reliability analyses are valid.

However, reliance on transmission to mitigate ENO's transmission issues will still hold ENO hostage to importing all of its power to meet its load requirements. Nor will transmission upgrades provide ENO with the benefits of operational flexibility, having a local dynamic source of power for voltage control, and system reliability support. Upgraded transmission will not alleviate the risk and consequences of ENO's system being islanded, as happened during Hurricane Gustav. In an islanding situation, without having local generation, ENO would not be able to supply its critical customer loads and potentially the S&WB Carrolton facility.

I have significant concerns with the constructability issues surrounding the upgrade projects which ENO has identified in its testimony and numerous discovery responses. ENO's planning level cost estimates for proposed transmission upgrades reflected in ENO's Supplemental Application constitute general rule-of-thumb estimates <u>which are not based</u> upon detailed engineering analysis and design studies, comprehensive field inspection of the circuits to be upgraded, etc., as further elaborated in my testimony. Based upon ENO's own admissions including ENO's indication that getting transmission outages necessary for its construction work will be problematic, the number of unknowns that exist including potential soil condition issues, access issues, obstructions and environmental mitigation issues, as well as the fact that ENO has not definitely demonstrated that its proposed projects are feasible and constructible on an accelerated basis, it is my opinion that reliance on ENO's Transmission Alternative poses potentially excessive risks to ENO's customers, and should not be considered as a realistic alternative until such time as ENO files with the Council: (1) a definitive showing that its proposed transmission upgrade projects are feasibly constructible; (2) a definitive project cost estimate based upon ENO's determination of the specific costs of its proposed transmission upgrade projects; and (3) a refined estimate of the time necessary to construct each proposed project. I would recommend that these tasks be completed prior to final approval of such plan. Though ENO identified a need-by in-service date of "by 2021" for all upgrade projects required by its Transmission Alternative, ENO has admitted that: *"…it is doubtful that all of the projects at issues can be completed before 2022."*[17] ENO also states:

"The Company has a reliability need that presently exists and should be addressed by a mitigation measure as quickly as possible. Upon further review of Table 1, the Company states that the dates in each row under the column "Need-by Date" should be amended to state "as soon as possible."[18]

Given ENO's admissions as to the urgency to get its transmission upgrade projects completed, and that it would not be able to complete the projects by even its originally proposed need-by date, I believe ENO's Transmission Alternative as filed presents the Council potentially excessive reliability risks. Should the Council elect to pursue this alternative, it should require ENO to file a definitive plan to be held to as discussed above.

[17] See ENO response to Advisors 12-3c.

Solar PV and DSM Alternatives

ENO has presented several alternative cases which include solar PV generation and DSM. My conclusions concerning each of these alternatives based upon my evaluation of ENO's transmission reliability analyses follow.

CT Alternative with 100 MW Solar PV and 2 Percent DSM: Similar to ENO's CT Alternative, I find that the addition of 100 MW solar PV generating capacity interconnected at Michoud, and 2 percent DSM, would fully mitigate ENO's transmission reliability issues, and would provide the local generation benefits I have identified in my discussion of the CT Alternative. This alternative would fully support ENO's transmission system reliability without the need for any transmission upgrades. However, showing that 100 MW of solar PV capacity can be sited in close proximity to the Michoud has not been demonstrated in this docket. In addition, as I have discussed earlier in my testimony, solar PV capacity would not support ENO's system restoration after a major outage event as it is not dispatchable and cannot be practically ramped up to follow load. Further, solar PV equipment is susceptible to physical damage from major storm events and may not be operable after such an event. Accordingly, though this alternative would satisfy ENO's reliability needs, the feasibility of the solar component is presently very much in question.

RICE Alternative with 100 MW Solar PV and 2% DSM: Similar to ENO's RICE Alternative, I find that the addition of 100 MW solar PV generating capacity interconnected at Michoud, and 2 percent DSM, would fully mitigate ENO's

[18] See ENO response to Advisors 12-4a.

transmission reliability issues, and would provide the local generation benefits I have identified in my discussion of the CT Alternative. This alternative would fully support ENO's transmission system reliability without the need for any transmission upgrades. However, ENO's transmission reliability analysis results indicate there would be a need to shed 25 MW of ENO customer load in 2019 to mitigate a P6 double contingency. However, showing that 100 MW of solar PV capacity can be sited in close proximity to the Michoud has not been demonstrated in this docket. Accordingly, though this alternative would satisfy ENO's reliability needs, the feasibility of the solar component is very much unknown as I have previously discussed herein.

Transmission Alternative with 200 MW of Solar PV and 2% DSM: Similar to ENO's Transmission Alternative, the addition of 200 MW of solar PV generating capacity interconnected at Michoud and 2 percent DSM would not avoid a system voltage collapse in 2019 in the event of a P6 double contingency. Assuming ENO's identified transmission upgrades estimated to cost $23.2 million are accomplished, this alternative would satisfy ENO's reliability needs in later years. However, this alternative would not provide the local generation benefits I have identified in my discussion of the CT Alternative. Neither would it be a practical resource to supply power to ENO's critical customers during an islanding event or major system outage. Further, a showing that 200 MW of solar PV capacity can be sited in close proximity to the Michoud has not been demonstrated in this docket. Accordingly, though this alternative would satisfy ENO's reliability needs in the longer term, the feasibility of the solar component is very much unknown as I have previously discussed herein.

Transmission Alternative with 2% DSM: Through the 2019 – 2027 years of study, this alternative performs similar to the Transmission Alternative. ENO transmission reliability analysis indicates that in the event of a P6 contingency, ENO's system would suffer cascading outages ultimately leading to a voltage collapse of its 115 kV network, resulting in placing approximately 49,000 ENO customers out of service. This contingency could be mitigated by ENO accomplishing $44.3 million of transmission upgrades. Similar to the Transmission Alternative, it is my opinion that this would be a risky alternative owing the ENO's stated constructability issues and unknowns. Further I note that this alternative would not provide the operating flexibility, and ability to power critical customer loads in the event of a major system outage or major storm event that the RICE Alternative would provide. Accordingly, I question the feasibility of this alternative absent the demonstration that it is realistically achievable.

Final Conclusions: Given ENO's stated constructability issues and unknowns concerning ENO's accomplishment of required transmission upgrades needed to mitigate its transmission reliability issues, it is my opinion that the Transmission Alternative, either with or without the inclusion of 2 percent DSM presents significant risk to New Orleans. As noted, to the extent the Council approves proceeding with this option absent the demonstration that it is realistically achievable, ENO should demonstrate that its proposed transmission upgrade projects can be constructed, the realistic timing of each project, the potential impacts of project delay on ENO's transmission reliability, and definitive costs for each project.

Likewise, for reasons already stated, the Transmission Alternative including 200 MW of solar PV capacity and 2 percent DSM contain dubious assumptions in ENO's transmission modeling and in order to realistically be considered ENO should demonstrate that its assumptions are accurate concerning the load forecast upon which its transmission reliability analyses are based, as well as the assumed capacity value of solar PV resources included in its model.

To the contrary, the CT Alternative and RICE Alternative, with and without 100 MW of solar PV capacity and 2 percent DSM, would fully mitigate ENO's transmission reliability issues, would provide operating flexibility, would be capable of powering critical ENO customer loads in the event of a major system outage or major storm event, and would support restoration of service after a major system outage. However, as I have explained, the CT Alternative and RICE Alternative are different when considering black start capability, which I view as a critical requirement given New Orleans risk of major storm event driven outages. The CT Alternative would rely on a transmission path from a remote source to black-start the unit. The RICE Alternative units have black-start capability built in, and would not require a source of power from an external source. In the event of a major system outage, I believe ENO's reliance on a remote transmission path and source of power for black-start service is a potentially excessive risk. Further, I note that Advisors Witness Joseph Rogers has testified that in his opinion the RICE Alternative would be a better choice than the CT Alternative, based upon not only capacity need, but the expected operational requirements for the unit.

Accordingly, after considering each of the alternatives presented in this docket for their ability to fully support ENO's transmission reliability and mitigate ENO's current transmission reliability problems, and for the reasons I have elaborated herein, when considering the inherent risks that each alternative presents, my preference would be the

RICE Alternative, either with or without inclusion of 100 MW solar PV capacity and 2 percent DSM (if it can be demonstrated that modeling assumptions in fact are realistic), as the alternative that mitigates the transmission risk in comparison to all others I have evaluated in my testimony. The RICE Alternative presents the least risk compared to both the CT Alternative and the Transmission Alternative.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

AFFIRMATION

STATE OF COLORADO)
)
COUNTY OF DENVER)

I, Philip J. Movish, am the person identified in the attached Testimony and such testimony was prepared by me or under my direct supervision; the answers and information set forth therein are true to the best of my knowledge and belief, and if asked the questions set forth therein, my answers thereto would, under oath, be the same.

Philip J. Movish

Subscribed and sworn to before me this 20th day of November, 2017.

NOTARY PUBLIC

ROBIN MARIE SHAVER-LaBARGE
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20064043695
MY COMMISSION EXPIRES APRIL 3, 2019