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

JOSEPH W. ROGERS, P.E.

ON BEHALF OF

THE ADVISORS TO THE

COUNCIL OF THE CITY OF NEW ORLEANS

PUBLIC REDACTED VERSION

November 20, 2017

PREPARED DIRECT TESTIMONY

OF

JOSEPH W. ROGERS

I. INTRODUCTION

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

A. My name is Joseph W. Rogers. My business address is 8055 East Tufts Avenue, Suite 1250, Denver, Colorado. I am a registered Professional Engineer in the States of Kansas, Colorado, and Louisiana and 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").

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[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.

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

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

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 my review of the Application, intervenor testimony, and discovery in this docket; to provide my recommendations regarding the Application to the Council.

Q. PLEASE SUMMARIZE YOUR MAJOR CONCLUSIONS AND RECOMMENDATIONS.

A. In my testimony, I present my review of ENO's application to construct the New Orleans Power Station ("NOPS") based on capacity need, economics, and sensitivity to the

Midcontinent Independent System Operator, Inc. ("MISO") capacity market. I conclude that, of the cases modeled, the economically preferred alternative appears to be construction of transmission upgrades and 100 MW of solar capacity instead of constructing NOPS. This alternative compares favorably under a significant range of capacity market price forecasts, however, the Council should not base its decision in this docket solely on economics. As Mr. Movish explains, reliance on this transmission alternative poses potentially excessive risk to ENO's customers, and that this transmission alternative should not be considered as a realistic alternative until such time as ENO files additional information with the Council.

Among the two NOPS configurations, I recommend that the Council strongly consider favoring the 128 MW project, consisting of seven Reciprocating Internal Combustion Engine ("RICE") generator sets, due to its better fit with ENO's load and capability needs especially when considering the Council's 2% DSM Goal, superior heat rate, operational flexibility, and black start capability in the event that New Orleans becomes disconnected from the regional transmission grid.

Lastly I conclude that, if the Council elects to construct NOPS, ENO's requested monitoring and reporting requirements should be modified as I have identified in my testimony.

II. ENO'S APPLICATION BEFORE THE COUNCIL

Q. WHAT IS ENO SEEKING IN 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 ("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 128 MW project, consisting of seven Reciprocating Internal Combustion Engine 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. I will refer to the originally proposed CT configuration of the Project as the "CT Alternative" and the alternatively proposed RICE configuration of the Project as the "RICE Alternative".

Q. PLEASE DESCRIBE BOTH PROPOSED CONFIGURATIONS OF THE NEW ORLEANS POWER STATION.

A. 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 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 an 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"[2] capability. Under the Council's 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 2018 and Notice to Proceed ("NTP") would be provided to the EPC contractor by March 1, 2018.[3]

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 standby diesel generator and compressed air system to

[2] Black Start Resource: a generating unit(s) and its associated set of equipment which has the ability to be started without support from the system or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, meeting the transmission operator's restoration plan needs for real and reactive power capability, and frequency and voltage control.

[3] The Supplemental Application at page 4 indicates that commercial operation could be achieved by November 2020, provided regulatory approval is received by the end of October 2017 and NTP is granted to the EPC contractor by November 1, 2017.

provide 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 2018 and Notice to Proceed ("NTP") would be provided to the EPC contractor by March 1, 2018.[4]

III. RESOURCE NEEDS

Q. PLEASE DESCRIBE THE COMPANY'S LOAD FORECAST PRESENTED IN THE INITIAL APPLICATION.

A. ENO's load forecast in the Initial Application is presented in a Highly Sensitive Protected Material ("HSPM") exhibit labeled Exhibit SEC-4. According to ENO's responses to Advisors' discovery, the forecast reflects forecasted peak loads from the Company's business plan BP16-Update. For reference, the load forecast contained in ENO's 2015 Integrated Resource Plan ("Final 2015 IRP") stakeholder input case reflects forecasted peak loads from the Company's business plan BP16. Over the 20 year planning period in the Initial Application, ENO's total load requirements (peak load plus 12 percent planning reserves) were estimated to grow from approximately [redacted] MW in 2016 to [redacted] MW in 2035. The forecast contained in the Initial Application, as compared to the Final 2015 IRP forecast, shows a near term increase in the forecasted total load requirements followed by

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4 The Supplemental Application at page 5 indicates that commercial operation could be achieved by October 2019, provided regulatory approval is received by the end of October 2017 and NTP is granted to the EPC contractor by November 1, 2017, is expected in October 2019

slower average annual growth. By 2030, the forecasted total load requirements in the Initial Application is [redacted] MW lower than that which was forecasted in the Final 2015 IRP; by 2035 it is [redacted] MW lower than the Final 2015 IRP.

Q. PLEASE DESCRIBE THE REASON FOR THE SIGNIFICANT DECREASE IN THE FORECASTED LONG-TERM LOAD REQUIREMENTS IN THE INITIAL APPLICATION AS COMPARED TO THE FINAL 2015 IRP.

A. I do not know the primary reason for the decrease, however, it appears to be generally related to updated input parameters. ENO was asked in discovery question Advisors 1-23 to reconcile the difference between the load requirements presented in the Final 2015 IRP and the load requirements presented in the Initial Application by identifying any differences in assumptions, input data, or methodologies. ENO's response to Advisors 1-23 indicated:

> *"No changes to ENO's forecasting methodology or assumptions were introduced between BP16 and BP16-U. As a result, differences in forecasted load requirements between the two business plans reflect the impact of refreshed input data into ENO's energy sales forecast models, to include: historical energy sales, historical weather, economic data, and customer end-use indices. Additionally, BP16-U reflects individual forecast updates for large customers."*

Q. ARE THE FORECASTED LONG-TERM LOAD REQUIREMENTS IN THE SUPPLEMENTAL APPLICATION THE SAME AS THOSE PRESENTED IN THE INITIAL APPLICATION?

A. No, ENO's estimates of total load requirements decreased again. The decrease in estimated load requirements was cited by ENO in its February 14, 2017 motion to suspend the procedural schedule in this proceeding. The suspension ultimately resulted in ENO filling the Supplemental Application.

Q. WHAT WAS THE MAGNITUDE OF THE DECREASE IN TOTAL LOAD REQUIREMENTS BETWEEN THE INITIAL APPLICATION AND THE SUPPLEMENTAL APPLICATION?

A. The forecast contained in the Supplemental Application shows a relatively flat projection of total load requirements over the forecast period with total load requirements increasing by less than [redacted] MW over the 20 year planning period; on average this level of growth is less than [redacted] MW per year. According to ENO, the decline in ENO's projected peak load from the projections contained in the Initial Application is primarily a result of a decline in residential and commercial usage per customer. In comparison, the forecasted total load requirements in the Supplemental Application, by 2030, is [redacted] MW lower than that which was forecasted in the Final 2015 IRP; by 2035 it is [redacted] lower than the Final 2015 IRP.

Figure 1 presents a comparison of the total load requirements (peak load plus 12 percent planning reserve margin) in the Final 2015 IRP, Initial Application, and Supplemental Application.

Figure 1 – Highly Sensitive Protected Material

[redacted]

The significant reduction in projected total load requirements since the 2015 Final IRP, where a 250 MW CT in 2019 was selected as part of the preferred portfolio, would strongly suggest that 226 MW may be greater than the optimal size for the proposed peaking plant on a capacity need basis.

Q. **BASED ON THE REVISED LOAD REQUIREMENTS IN THE SUPPLEMENTAL APPLICATION WHAT IS THE COMPANY'S OVERALL CAPACITY NEED?**

A. In the Supplemental Application, ENO indicates that the Company has overall need for capacity of approximately 99 MW by 2026, growing to 248 MW by 2036.[5] These numbers are derived from Exhibit SEC-11. However, a review of Exhibit SEC-11 reveals that while ENO accounted for the effects of existing demand side management ("DSM") programs, they did not incorporate reductions in the load requirements for future DSM programs.

The Council has expressed strong support for DSM and energy efficiency through the Energy Smart program. The Council's Utility, Cable, Telecommunications and Technology Committee ("UCTTC") accepted ENO's Final 2015 IRP for the purpose of Energy Smart implementation and, subsequently, approved levels for Energy Smart Program Years 7 through 9 which were consistent with the goal of increasing the projected savings from the Energy Smart program by 0.2% per year. The goal of increasing the projected savings from the Energy Smart program by 0.2% per year is contained in what I refer to as the Council's 2% DSM Goal which is expressly stated in Council Resolution No. R-15-599:

> "*WHEREAS, the Council believes it would be reasonable in the development of subsequent Energy Smart Program Years (Program Year 7 and beyond) for the Company to incorporate in its Energy Smart and IRP filings for evaluation by the Advisors, Intervenors, and the Council the goal of increasing the projected savings from the Energy Smart program by 0.2% per year, until such time as the program generates kWh savings at a rate equal to 2% of annual kWh sales; now therefore;*"

[5] Supplemental and Amending Direct Testimony of Seth E. Cureington at page 7

Accordingly, I believe that the expectation that DSM through the Energy Smart program would continue and expand in the future should have, at a minimum, been evaluated in ENO's load and capability calculations. I suspect, in accordance with the provisions of Council Resolution No. R-15-599, the Advisors, Intervenors, and the Council will continue to evaluate the Council's 2% DSM Goal by weighing the costs and benefits of that goal as Energy Smart continues to grow. That said, the Council has approved savings levels for Energy Smart that are consistent with the Council's 2% DSM Goal through 2019 and I believe it would be appropriate to consider the Council's 2% DSM Goal in evaluating the Company's overall capacity need. As such, I have utilized ENO's estimates of the peak impact associated with implementing the DSM required to achieve the Council's 2% DSM Goal to adjust the data contained in Exhibit SEC-11 to identify the load and capability requirements if the Council's 2% DSM Goal is achieved. Figure 1 presents the load and capability that is consistent with ENO's stated overall need for capacity of approximately 99 MW by 2026, growing to 248 MW by 2036.[6] Figure 2 presents the load and capability requirements if the Council's 2% DSM Goal is achieved.

[6] Supplemental and Amending Direct Testimony of Seth E. Cureington at page 7

Figure 2 – Highly Sensitive Protected Material

[redacted]

Figure 3 – Highly Sensitive Protected Material

[redacted]

Q. WHAT IS THE SIGNIFICANCE OF THE LOAD AND CAPABILITY IN THIS PROCEEDING?

A. Beyond demonstrating the need for the Project, the Council in Resolution No. R-17-100 expressed that the size and timing of the Project be fully vetted in this Docket. As proposed, the earliest the Project could be reasonably expected to achieve commercial operation is early 2020. A review of Figure 3 shows an immediate need for approximately [redacted] MW of capacity. However, by 2020 as Energy Smart continues to grow in accordance with the Council's 2% DSM Goal, the savings from demand side measures outpaces the estimated increase in total resource requirements from load growth and existing resource retirements resulting in a projected reduced capacity shortfall declining to [redacted] by 2030 then increasing to [redacted] MW by 2036. This suggests from a capacity planning perspective that, if Councils 2% Goal can be achieved, the 128 MW RICE Alternative is a better fit with ENO's capacity needs than the 226 MW CT Alternative.

IV. SIZE OF THE PROJECT

Q. THE 226 MW PROJECT SIZE OF THE CT ALTERNATIVE IS CONSIDERABLY LARGER THAN THE NEAR TERM NEED SHOWN IN FIGURE 3 WITH OR WITHOUT CONSIDERATION OF THE COUNCIL'S 2% DSM GOAL; HOW WAS THE PROJECT SIZED?

A. The origins of the Project sizing are in the 2015 IRP process. The 2015 Draft Integrated Resource Plan ("Draft 2015 IRP") was filed in June 2015 and included in the Preferred Portfolio a 194 MW CT addition in 2019.

As part of the IRP, ENO performed a Technology Assessment in which ENO screened a wide range of generation technologies to define a set of reference supply-side generation technologies that would be modeled in the IRP process. The final set of supply-side generation technologies included: pulverized coal generation, combustion turbines, combined cycle gas turbines ("CCGT"), internal combustion engines, generation from biomass, nuclear, wind, solar, and battery storage. Specifically, with respect to peaking technologies modeled in the IRP, ENO included six different internal combustion engine and CT technologies ranging from 19 MW to 194 MW.

To select from this pool of resources, and after consideration of demand-side management ("DSM") resources, ENO utilized the AURORxmp ("AURORA") Capacity Expansion Model.[7] As ENO explains, AURORA utilizes a linear optimization process and iterative calculations to find the optimal combination of resources to meet projected load-serving needs. However, the capacity expansion portfolios that were developed by the AURORA optimization engine did not select a CT. Rather, in three of the four macro-economic

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7 AURORAxmp Energy Market Model is a computer based model developed by EPIS, Inc. for electric market price forecasting and capacity expansion modeling. The AURORAxmp Energy Market Model includes automated resource optimization logic.

scenarios[8] AURORA selected a 382 MW CCGT resource in 2019. In the fourth scenario, a scenario favorable to generation with low CO_2 emissions, AURORA selected 1,150 MW of solar resources and 50 MW of wind resources.

Q. IF THE AURORA EXPANSION MODEL OPTIMIZATION SELECTED A CCGT IN THE MAJORITY OF THE MACRO-ECONOMIC SCENARIOS, WHY WAS A 194 CT INCLUDED IN THE PREFERRED PORTFOLIO OF THE DRAFT 2015 IRP?

A. The 194 MW CT in 2019 was not a result of the AURORA optimization process. In the Final 2015 IRP ENO explained:

> *"In AURORA, a resource is dispatched based on its ability to serve the load in MISO, regardless of who owns the generating resources. Because CCGT resources are expected to be dispatched before peaking resources due to their relative efficiency, the selection by AURORA of CCGT resources to serve load in MISO is predicated on the need for the energy those resources are dispatched to serve. ENO's challenge is that while CCGT resources may be more economic than peaking resources (e.g., CTs), it would not be prudent for ENO to add CCGT resources to its capacity portfolio if it does not have a corresponding need for the energy those resources are expected to produce when dispatched by MISO. If ENO were to add more CCGT resources beyond Union Power Block 1 than can be supported by the supply role needs analysis discussed in Section 3, effectively ENO would be exposing its customers to unnecessary risk associated with the known high fixed cost of CCGT resources as compared to the unknown market price for the excess energy necessary to make those resource additions economic."*[9]

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[8] The potential future scenarios considered in the IRP are: Industrial Renaissance (reference load), Business Boom, Distributed Disruption, and Generation Shift.

[9] Final 2015 IRP p 55

As a result of this, ENO, outside of the AURORA Capacity Expansion Model, designed four new generation portfolios each with a 194 MW CT in 2019.

Q. HOW DID THE CT ALTERNATIVE COME TO BE SIZED AT 226 MW?

A. In an attempt to address comments and concerns raised by the Advisors and Intervenors regarding the Draft 2015 IRP, ENO developed additional portfolios and performed additional production cost analyses prior to filing the Final 2015 IRP on February 1, 2016. These additional analyses were included in the Final 2015 IRP and were referred to as the Stakeholder Input Case. It was in the development of these additional analyses that the Company abruptly switched from a 194 MW CT to a 250 MW CT. The increase in size was not a result of AURORA optimization process. For all portfolios in the Draft 2015 IRP that included an 194 MW CT, ENO simply replaced the 194 MW CT with a 250 MW CT for the Stakeholder Input Case. The Preferred Portfolio in the Final 2015 IRP is based on the Stakeholder Input Case and includes a 250 MW CT in 2019.

The 250 MW CT modeled in the Final 2015 IRP is based on the MHPSA 501GAC CT which is the same technology that is proposed for the CT Alternative. The 250 MW rating is the nominal rating of the CT at standard conditions. The 226 MW rating is based on summer conditions of 97 °F and 59% relative humidity.[10]

Q. HOW DID THE RICE ALTERNATIVE COME TO BE SIZED AT 128 MW?

[10] Direct Testimony of Jonathan E. Long at page 5

A. In response to the updated load forecast, ENO engaged WorleyParsons to conduct a study regarding the Company's potential options for a smaller resource.[11] The Company looked at potential combustion turbine and RICE alternatives with a net plant output between 106 MW and 128 MW and ultimately concluded that the currently proposed 128 MW RICE Alternative had the lowest levelized cost of electricity on a $/MWh basis as well as other benefits such as low water usage, a low emissions profile, the ability to support renewable resources, and black-start capability.[12]

Q. BASED ON YOUR TESTIMONY IT APPEARS THAT NEITHER THE SIZE OR TIMING OF THE PROJECT WAS OPTIMIZED AS PART OF THE IRP PROCESS; IS THAT CORRECT?

A. Yes, that is correct. Neither the size or timing of the Project was optimized as part of the IRP process. The size of the CT Alternative evolved from ENO's initial selection of a 194 MW CT outside of the AURORA optimization process in the IRP process. The size of the RICE Alternative appears to be a result of the evaluation of options slated for consideration in a WorleyParsons study performed for ENO regarding peaking units in the 100 MW to 150 MW size range. The timing was originally chosen by ENO, as well, and appears to have been based on the timing of the optimized selection of the CCGT resource. The

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[11] Supplemental and Amending Direct Testimony of Jonathan E. Long at page 6

[12] Supplemental and Amending Direct Testimony of Jonathan E. Long at page 6

current timing of either the CT Alternative or RICE Alternative appears to be "as soon as possible" based upon the anticipated schedule durations for each of the alternatives.

V. ENO'S ECONOMIC ANALYSES

Q. WHAT IS THE SIGNIFICANCE OF YOUR STATEMENT THAT NEITHER THE SIZE OR TIMING OF THE PROJECT WAS OPTIMIZED AS PART OF THE IRP PROCESS?

A. From my perspective, it suggests that ENO cannot solely rely on the economic analyses presented in the IRP to demonstrate a case for the NOPS unit.

Q. WHAT ECONOMIC ANALYSES HAS ENO PROVIDED IN SUPPORT OF THE PROJECT IN THIS DOCKET?

A. ENO has provided no less than three sets of economic analyses in this proceeding. One set with the Company's Initial Application, one set as part of the Supplemental Testimony, and one set with the Supplemental Application.

In the Initial Application ENO generally provided a screening analyses of CT Alternatives. The analyses included with the Supplemental Testimony was required by Council Resolution R-16-506 and in response to a September 19, 2016 request by the Council's Advisors for ENO to perform additional AURORA IRP modeling to assist the Council in determining whether the construction of NOPS is necessary and in the public interest. Lastly, the analyses included with the Supplemental Application were also developed utilizing the AURORA production cost modeling software and were, in part, informed by the Advisors' recommendations.

Q. WHY DID THE COUNCIL'S ADVISORS MAKE THE SEPTEMBER 19, 2016 REQUEST THAT ENO TO PERFORM ADDITIONAL AURORA ANALYSES?

A. The process to develop the Final 2015 IRP took place over a period of more than 20 months beginning in the first half of 2014 and culminating in the filing of the Final 2015 IRP in February 2016. During that time period, and after the Final 2015 IRP was filed, new developments and changes transpired that were not fully incorporated in the IRP process and, accordingly, warranted further analyses. These developments and changes included:

- The acquisition by ENO of the electric utility operations and certain assets serving the Fifteenth Ward of the City of New Orleans from ELL in September of 2015 ("Algiers Transaction").
- On December 10, 2015 in Council Resolution R-15-599, the Council expressed its 2% DSM Goal.
- The Union Power acquisition changed from an initially planned 198 MW PPA for a 20 percent share of the capacity and associated energy of Power Blocks 3 and 4 to the Company's purchase of Power Block 1 comprising approximately 495 MW. The acquisition closed on March 3, 2016.

- In its June 26, 2016 application in this docket, ENO indicated that "…the exclusion of NOPS would likely involve the construction of multiple new transmission facilities in the greater New Orleans area, each of which would be difficult and costly to construct given the limited land availability and environmental challenges associated with transmission line construction in that region…"; thereby suggesting that there may be a transmission alternative to the installation of NOPS.

- As discussed earlier in my testimony, in its Initial Application in this docket, on June 26, 2016, ENO included a load forecast which was dramatically different than the forecast used in the Final 2015 IRP forecast.

- On August 29, 2016 in response to Advisors discovery question 1-25, ENO informed the Advisors that ENO was committed to deploying AMI within its service territory and would be making a filing seeking Council approval in October 2016. ENO submitted the referenced filing to the Council on October 18, 2016.

- ENO made a commitment to the Council that they would seek up to 100 MW of renewables

All of these developments and changes could result in material increases in costs to ratepayers and could alter the ultimate decision of the Council with respect to the Project. The Advisors requested the alternate cases analyses to ensure that the Council had additional current information to inform their decisions on the NOPS proposal and other issues in the near term – decisions that could likely be made prior to the next iteration of the triennial IRP process. For reference I will refer to these analyses as the Alternate Cases Analyses ("A.C.A.").

Q. PLEASE DESCRIBE THE ALTERNATE CASES ANALYSES THAT THE ADVISORS ASKED ENO TO PERFORM.

A. Exhibit SEC-8 included in ENO's November 18, 2016 Supplemental Direct Testimony in this docket is an accurate copy of what the Advisors provided to ENO with respect to the four additional modeling cases. The four cases generally built off of the Stakeholder Input Case from the IRP with updated assumptions including: 1) a load forecast consistent with the Business Plan 16 update and the Initial Application, 2) a natural gas price forecast consistent with the Business Plan 16 update, 3) an updated CO_2 price forecast, 4) an increase in the renewable capacity to 100 MW, 5) inclusion of the effects of planned and recently completed transmission upgrades, and 6) inclusion of the effects of any planned new generating resources including the proposed St. Charles Power Station.

The four cases were designed to inform the Council on the effects of three potential decisions facing the Council. Each case was designed to isolate an individual decision by changing only one assumption and thereby provide a cost impact associated with that decision. A.C.A. Case 1 includes NOPS and is the base case. A.C.A. Case 2 sought to inform the Council with respect to the decision to proceed with NOPS by assuming that in lieu of NOPS, ENO makes the necessary transmission upgrades to be in compliance with NERC Standard TPL-001-4. A.C.A. Case 3 sought to inform the Council with respect to the Council's desire to evaluate the goal of increasing the projected savings from the

Energy Smart program by 0.2% per year, until such time as the program generates kWh savings at a rate equal to 2% of annual kWh sales. Lastly, A.C.A. Case 4 was designed inform the Council on the extent to which AMI will facilitate demand-side management and the impact of AMI on the NOPS proposal.

Q. HAVE YOU REVIEWED THE ALTERNATE CASES ANALYSES?

A. Yes. I have reviewed the analyses provided in the spreadsheet included with ENO's Supplemental Direct Testimony and the supporting spreadsheets obtained through discovery. I note, for clarity, that ENO chose not to evaluate A.C.A Case 3 as requested; rather ENO developed an breakeven analyses with A.C.A. Case 1 which effectively calculated the level of DSM investment that would result in the same net present value ("NPV") of A.C.A. Case 1.

Q. SHOULD THE COUNCIL RELY ON THE ALTERNATE CASES ANALYSES PRESENTED IN THE ENO'S NOVEMBER 18, 2016 SUPPLEMENTAL DIRECT TESTIMONY IN THIS DOCKET ?

A. No. While those cases were relevant and informative at the time the Advisors requested the alternate case analyses, the cases presented in the November 18, 2016 Supplemental Testimony 1) cannot be directly compared with the analyses presented in the Supplemental Application primarily due to the change in the load forecast; 2) do not contain a scenario with the proposed 128 MW RICE Alternative; and, 3) only partially considered the Council's 2% DSM Goal due to the breakeven style of analyses.

Q. WHAT CAUSED THE SUPPLEMENTAL APPLICATION AND THE ASSOCIATED ECONOMIC ANALYSES TO BE FILED ?

A. On February 14, 2017, ENO filed a motion to temporarily suspend the procedural schedule in this docket and requested a subsequent status conference. On February 21, 2017, the Hearing Officer granted the motion to temporarily suspend the procedural schedule and set the requested status conference for March 6, 2017. The status conference was held on March 6, 2017, and ENO reported that due to its new load forecast information, it would be submitting a supplemental amended application within approximately 60-90 days and that it would file a motion before the Council to adopt a new procedural schedule with the amended application.

Q. DID THE ADVISORS PROVIDE RECOMMENDATIONS REGARDING ENO'S ANALYSES IN THE SUPPLEMENTAL APPLICATION ?

A. Yes. To ensure that any amended application filed by ENO contained sufficient and supporting information for the Council, as well as the parties in the Docket, to evaluate any revised request for approval to construct the NOPS; the Council's Advisors provided recommendations to ENO on March 23, 2017. The Advisor's recommendations are attached as Exhibit No. ____(JWR-4).

Q. WAS ENO RESTRICTED TO PERFORM ONLY THE ANALYSES THAT THE ADVISORS RECOMMENDED?

A. No. In fact it was ENO's proposal that a supplemental application would be appropriate. Presumably, ENO was generally aware of what types of information and analyses would be necessary with their supplemental application when they proposed filing the supplemental application. The Advisors' recommendations with respect to the supplemental filing were specifically identified as a recommended minimum and were designed to ensure that the supplemental filling contained at least the level of information that the Advisors identified as being necessary for the Council and Parties to the docket to evaluate any revised request for approval regarding the Project.

Q. WHAT WAS THE NATURE OF THE ADVISORS' RECOMMENDATIONS REGARDING ENO'S ANALYSES IN THE SUPPLEMENTAL APPLICATION?

A. Similar to the Alternative Cases Analyses, the Advisors wanted to ensure that ENO provided the Council with an 20-year economic analyses that 1) included current and consistent assumptions including the Council's 2% DSM Goal; 2) was based on utilizing the AURORA optimization engine and included at least two optimized portfolios with one being the proposed re-sized NOPS alternative (in this manner the Council would have a least cost optimized portfolio to compare with the NOPS proposal); 3) included sensitivities that addressed fuel costs and capacity prices, and; 4) included the associated transmission load flow analyses consistent with the economic analyses.

Essentially the analyses requested by the Advisors were designed to partially mimic a portion of the IRP optimization process.

Q. DID ENO ADHERE TO THE ADVISORS' RECOMMENDATIONS FOR THE ANALYSES IN THE SUPPLEMENTAL APPLICATION?

A. Only partially, while ENO, through the Supplemental Direct Testimony of Seth E. Cureington portrays the results presented in his Testimony as "requested portfolios" the portfolios and associated analyses <u>are not</u> what the Advisors recommended and <u>were not</u> based on an optimization analyses. Rather, the "requested portfolios" put forth by ENO represent four portfolios that ENO designed. These four portfolios were presented in the Supplemental Application along with three "reference portfolios."

To avoid perpetuating the myth that the Advisors requested the portfolios that ENO provided, I will refer to the ENO's "reference portfolios" as "cases without additional DSM" and I will refer to ENO's "requested portfolios" as "cases with the Council's 2% DSM Goal". Further, to facilitate a common understanding of the portfolios among all parties, I will utilize the same numbering nomenclature that ENO used for each of the portfolios. In the Supplemental Application, ENO provided analyses for the following portfolios:

<u>Cases without additional DSM</u>

- Case 1 – 128 MW RICE Alternative (2020), 100 MW Solar(2020)
- Case 1G – 226 MW CT Alternative (2020), 100 MW Solar(2020)
- Case 2 – Transmission Alternative, 100 MW Solar(2020)

<u>Cases with the Council's 2% DSM Goal</u>

- Case 3 – 128 MW RICE Alternative (2020), 100 MW Solar(2020), Council's 2% DSM Goal
- Case 3G – 226 MW CT Alternative (2020), 100 MW Solar(2020) Council's 2% DSM Goal
- Case 4A – 200 MW Solar(2020), Council's 2% DSM Goal
- Case 4B – 100 MW Solar(2020), 300 MW Wind (2020), Council's 2% DSM Goal

Q. HAVE YOU REVIEWED ENO'S ANALYSES IN THE SUPPLEMENTAL APPLICATION?

A. Yes. I have reviewed the analyses provided in the spreadsheets supporting the results presented in ENO's Supplemental Application.

Q. PLEASE REITERATE THE RESULTS OF ENO'S ANALYSES IN THE SUPPLEMENTAL APPLICATION UNDER THE REFERENCE GAS FORECAST?

A. Table 1 and Table 2 present the results that ENO provided in the Supplemental Application on page 5 of the Supplemental Direct Testimony of Seth E. Cureington as modified by ENO in response to discovery question Advisors 14-1. I note that discovery question Advisors 14-1 was initiated by the Advisors' discovery of an error made by ENO in the cases related to the CT Alternative (Case 1G and Case 3G). The order of magnitude of the error in each case was nominally $150 million of additional make whole payments being included in the variable supply cost component. While ENO in response to discovery question Advisors 14-1 acknowledged the error, ENO's revised results of the analyses oddly showed little change in the overall results after ENO purportedly corrected for the significant error. Upon reviewing the workpapers provided in response to discovery question Advisors 14-1, the Advisors noted that ENO had made adjustments to three of the other components which comprise the variable supply cost. The adjustments to these other components mitigated the effect of the errors related to the make whole payments. The Advisors have, through discovery, requested supplemental information in support of the changes that were curiously included but not revealed or explained in the initial discovery response to the observed error. Accordingly, I reserve the right to amend my testimony based on responses to the outstanding discovery on this matter. That said, Table 1 includes those cases modeled without additional DSM; Table 2 includes those cases modeled by ENO that include the Council's 2% DSM Goal.

Table 1 – Highly Sensitive Protected Material

Cases Without Additional DSM ENO's Results as Updated in Response to Advisors 14-1 $2017MM, NPV(2017 - 2036)					
			Case 1	Case 1G	Case 2
1	Variable Cost	[$MM]	[redacted]		
2	DSM Fixed Costs	[$MM]			
3	RICE Alternative Fixed Costs	[$MM]			
4	CT Alternative Fixed Costs	[$MM]			
5	Solar Fixed Costs	[$MM]			
6	Wind Fixed Costs	[$MM]			
7	Transmission Fixed Costs	[$MM]			
8	Capacity Purchases/(Sales)	[$MM]			
	Total Cost	**[$MM]**			
	Variance to Least Cost	**[$MM]**			
	% Variance to Least Cost	**%**			

Notes:
Case 1 – 128 MW RICE Alternative (2020), 100 MW Solar(2020)
Case 1G – 226 MW CT Alternative (2020), 100 MW Solar(2020)
Case 2 – Transmission Alternative, 100 MW Solar(2020)

Table 2 – Highly Sensitive Protected Material

Cases With Council's 2% DSM Goal ENO's Results as Updated in Response to Advisors 14-1 $2017MM, NPV(2017 - 2036)						
			Case 3	Case 3G	Case 4A	Case 4B
1	Variable Cost	[$MM]	[redacted]			
2	DSM Fixed Costs	[$MM]				
3	RICE Alternative Fixed Costs	[$MM]				
4	CT Alternative Fixed Costs	[$MM]				
5	Solar Fixed Costs	[$MM]				
6	Wind Fixed Costs	[$MM]				
7	Transmission Fixed Costs	[$MM]				
8	Capacity Purchases/(Sales)	[$MM]				
	Total Cost	**[$MM]**				
	Variance to Least Cost	**[$MM]**				
	% Variance to Least Cost	**%**				

Notes:
Case 3 – 128 MW RICE Alternative (2020), 100 MW Solar(2020), Council's 2% DSM Goal
Case 3G – 226 MW CT Alternative (2020), 100 MW Solar(2020) Council's 2% DSM Goal
Case 4A – 200 MW Solar(2020), Council's 2% DSM Goal
Case 4B – 100 MW Solar(2020), 300 MW Wind (2020), Council's 2% DSM Goal

Q. PLEASE PROVIDE YOUR OBSERVATIONS REGARDING THE RESULTS OF ENO'S ANALYSES IN THE SUPPLEMENTAL APPLICATION AS MODIFIED BY ENO IN RESPONSE TO DISCOVERY QUESTION ADVISORS 14-1 ?

A. Notwithstanding the observation that in both Table 1 and Table 2 the CT Alternative is shown as the least cost alternative with respect to total cost, I have four general observations. First, with respect to the overall results, I believe it is important to look at the relative differences between the cases in two groups. The first group, Table 1, contains results for cases that assume that no additional DSM beyond maintaining the DSM levels from program year 2016. The second group Table 2 contains results for cases that assume that DSM programs will grow and achieve the Councils' 2% DSM Goal. Accordingly, I do not believe it is appropriate to compare the results of one group with the other unless it is to compare two cases with identical generating portfolios for the purpose of determining the impact of the DSM assumption. In both Table 1 and Table 2, ENO identifies the portfolio with the CT Alternative as the least cost.

Second, ENO's results as presented in Tables 1 and 2 in my testimony are shown on a "levelized real" basis. The levelization by ENO was performed only on the revenue requirements associated with capital investment and fixed operation and maintenance ("O&M") costs. The levelized method consisted of determining a set of annual numbers escalating at two percent per year for the depreciation life of the asset that have the same net present value as the calculated fixed revenue requirements for the life of the asset. The calculated fixed revenue requirements of an asset are characterized by a generally decreasing annual revenue requirements due to depreciation. Accordingly, the levelized method ENO used, while it produces the same net present value over the life of the asset, tends to shift annual revenue requirements from earlier years to later years. Additionally, keep in mind that the results as presented consider annual values from 2016 through 2036 and not the complete depreciation life of the asset. Depending on the life of the asset, the levelized method tends to push a portion of the total revenue requirements further outside of the net present value period which extends only to 2036. As such, utilizing the levelized method that ENO used tends to favor cases that are more capital intensive.

In the spreadsheet that accompanied the Supplemental Direct Testimony, ENO also calculated the results on a more typical non-levelized net present value basis. These non-levelized results more accurately capture the actual annual revenue requirements associated with each of the cases and are appropriate for assessing the impact of a decision over the 20-year planning period.

Third, as noted in the Direct Testimony of Byron S. Watson, in two of the cases ENO's analyses included transmission upgrade investments that were inconsistent with information subsequently provided by ENO in the docket. As such, ENO's results as presented require adjustment to be consistent with ENO's representations.

Fourth, a review of Table 1 shows roughly a 3% difference between the Case 1G, the CT Alternative and Case 2, the Transmission Alternative. This relatively small percentage difference in the 20 year net present value suggests that on an economic basis, the Council may be economically indifferent to the two scenarios when considering the accuracy by which the next 20 years can be estimated. However, the Council may be less indifferent if capacity market price risk is considered. The magnitude of dollars associated with capacity market prices is evident in the swing in MISO capacity purchases and sales. In Case 1G there is $113 million net present value in MISO capacity market revenues; in Case 2 there is $72 million net present value in MISO capacity market purchases. This $185 million net present value swing in MISO capacity costs when compared to the $19 million net present value difference in variable costs and $54 million net present value difference in total costs between Case 1G and Case 2 suggests that the results of the analyses are significantly impacted by the level of ENO's PRA capacity price forecast.

VI. <u>MISO MARKET RISK</u>

Q. MR. CUREINGTON SUGGESTS THAT NOPS WILL MITIGATE RISK TO ENO'S CUSTOMERS ASSOCIATED WITH PRICE VOLATILITY AND EXPECTED HIGHER CAPACITY PRICES IN THE MISO PLANNING RESOURCE AUCTION; DO YOU AGREE?

A. No, not exactly. I agree that risk will be mitigated in that ENO's customers will now be paying the known fixed costs associated with NOPS rather than purchasing or selling in the MISO Planning Resource Auction ("PRA") for the Zonal Resource Credits associated with NOPS. However, it is also important to consider the ultimate cost to customers of that risk mitigation and the total load requirements of ENO relative to their supply-side and demand-side resources.

I agree with the Company that it would not be appropriate to rely on the MISO annual PRA to meet long-term resource needs. However, I also believe that it would not be appropriate to rely on expected revenue stream from the PRA to make a resource decision economic. I believe that a regulated LSE should strive over the long-term to acquire the appropriate mix of resource types (baseload, intermediate, and peaking) that match the LSE's expected load profile and rely on the MISO markets to meet limited short-term differences in resources and loads. With that preface, I believe ENO should acquire resources to match load requirements over the long-term.

ENO's planning assumption regarding capacity prices is that market equilibrium (where supply and demand balance) in MISO South will occur around 2022. Further, ENO assumes that as market equilibrium approaches, capacity prices will reflect new build prices. A proxy for new build prices in MISO is the Cost of New Entry ("CONE") which is the annualized capital cost of constructing a power plant expected to be operated in a peaking role. CONE is utilized by MISO primarily to establish the maximum clearing price in the Planning Resource Auctions.

ENO is located in MISO Local Resource Zone ("LRZ") 9. PRA capacity prices in LRZ 9 have been significantly below the Cost of New Entry ("CONE") since LRZ 9 was established when Entergy joined MISO in December of 2013. Table 3 presents a comparison of the historic PRA clearing prices in LRZ9 and the MISO calculated CONE price.

Table 3 MISO PRA Clearing Price for LRZ 9 vs. CONE Value for LRZ 9			
Planning Year	**Auction Clearing Price for LRZ 9**	**CONE Value for LRZ 9**	**ACP % of Cone**
	($/kW - Yr)	**($/kW - Yr)**	**($/kW - Yr)**
2014-2015	6.00	86.53	7%
2015-2016	1.20	86.95	1%
2016-2017	1.09	91.69	1%
2017-2018	0.55	91.77	1%

A review of the table shows that PRA clearing prices have historically been only a fraction of the CONE value. As I discuss later in my testimony it is currently unknown when or if capacity prices in LRZ 9 will approach CONE.

Consequently, if ENO does not have enough resources to satisfy its Resource Adequacy Requirements, ENO’s customers are subject to the risk that PRA capacity prices will go higher than the cost for which ENO could have acquired its own resource. On the other side of the coin, if ENO acquires excess resources beyond its Resource Adequacy Requirements, ENO’s customers are subject to the risk that PRA capacity prices will remain low and they will be saddled with the certain fixed costs of the excess acquired resources without adequate compensation from the PRA to off-set the excess fixed costs.

Obviously, ENO cannot exactly build to meet its Resource Adequacy Requirements each year, but the closer ENO is able to match load requirements and resources, the lesser the ratepayers of the City of New Orleans will be exposed to risk associated with PRA capacity prices.

Q. IS YOUR BELIEF THAT THE PRA SHOULD GENERALLY BE USED TO MEET LIMITED SHORT-TERM DIFFERENCES IN RESOURCES CONSISTENT WITH WHAT THE COMPANY HAS ARGUED?

A. Yes, I believe it is. First, it is consistent with the Company's plan to meet near-term peaking and reserve capacity and energy needs through the MISO markets until the Project is constructed.[13] Second, in his Direct Testimony, Mr. Cureington states: "*While the MISO PRA provides a short-term option to meet customers' needs, over-reliance on the short-term market in lieu of long-term resources – especially at a time when market conditions are expected to begin tightening toward equilibrium – involves greater risk compared to a long-term resource such as NOPS…*"[14] Further, Mr. Cureington makes a point of highlighting that the uncertainty associated with relying on the MISO annual PRA to meet long-term resource needs exposes customers to greater risk.[15]

Q. YOU MENTIONED THE RISK ASSOCIATED WITH BUILDING IN EXCESS OF ENO'S NEEDS IN RELATION TO THE CAPACITY MARKET; CAN YOU EXPAND ON THAT POINT?

A. Yes. I believe my point is almost identical to the position ENO took in the Draft 2015 IRP and Final 2015 IRP when they elected to develop the four additional CT portfolios outside of the AURORA optimization process. The exception is that ENO was concerned about

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[13] Direct Testimony of Seth E. Cureington at page 19

[14] Direct Testimony of Seth E. Cureington at page 30

[15] Direct Testimony of Seth E. Cureington at page 33

MISO energy price risk and I am addressing PRA capacity price risk. In the IRP, ENO was concerned with *"….exposing its customers to unnecessary risk associated with the known high fixed cost of CCGT resources as compared to the unknown market price for the excess energy necessary to make those resource additions economic."*[16] Here, I am addressing a concern with exposing ratepayers to unnecessary risk associated with the known fixed cost of CT resources as compared to the unknown market price for the excess capacity necessary to make those resource additions economic.

VII. <u>ENO's MISO CAPACITY MARKET PRICE FORECAST</u>

Q. WHAT IS THE BASIS FOR ENO'S CAPACITY MARKET PRICE FORECAST?

A. ENO's MISO South Capacity Price Curve (as of May 2016) is incorporated in the November 18, 2016 Supplemental Direct Testimony of ENO. ENO's projection for PRA capacity prices begins with a price curve that starts at [redacted] in 2016 and ramps up exponentially to MISO South market equilibrium in 2022. The PRA capacity price at equilibrium is equal to [redacted] of the CONE value, which is represented by the cost of a new-build CT including fixed operation and maintenance costs. Beyond 2022, the PRA capacity prices are assumed to increase at a projected inflation rate of [redacted] Figure 4 presents the historic PRA clearing price for LRZ 9 as compared to ENO's forecast.

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[16] Final 2015 IRP p 55

Figure 4 – Highly Sensitive Protected Material

[redacted]

Q. ENO'S FORECAST OF CAPACITY PRICES IS CONSIDERABLY HIGHER THAN THE RECENT ACP IN LRZ 9; DO YOU HAVE ANY CONCERNS REGARDING THE MAGNITUDE OF ENO'S CAPACITY PRICE FORECAST?

A. Yes. ENO's forecast is based on: 1) ENO's planning assumption that market equilibrium (where supply, including third party resources, and demand balance) in MISO South will occur around 2022, and 2) as market equilibrium approaches, capacity prices will reflect new build prices. ENO's approach is generally based on the theory of supply and demand, however, that theory may not be applicable to capacity prices in MISO South. As the

Brattle Group noted in a May 15, 2016 letter to the Director of Natural Resources and Environmental Issues in response to U.S. Senators' capacity market questions:

> *"Prices in MISO's capacity auction have been consistently near zero and are not likely to rise sufficiently to attract new generation investments when needed. In most of MISO, capacity needs are satisfied through state resource planning efforts by regulated, vertically-integrated utilities such that there is no need for additional capacity to be attracted through MISO's capacity auction. That is, the capacity market in MISO is not really the prime driver of entry or expansion decisions. Rather, it is more of a balancing market for temporary variance in the timing or performance of assets being developed for other reasons, under state requirements."*[17]

This perspective was before FERC in Docket ER-17-284 (Competitive Retail Solution Docket). In that docket MISO proposed to implement a three-year forward resource auction for only the Competitive Retail Areas[18] of MISO while retaining the existing PRA construct for the remainder of MISO.[19] In its November 16, 2016 filing MISO explains:

> *"The vast majority of MISO States do not depend solely on market price signals for generation resource investment. Traditionally-regulated States have successfully ensured, through integrated resource planning, that their load serving entities ("LSEs") have sufficient capacity to meet load obligations. To the extent additional capacity is necessary, LSEs subject to state supervision and authority have a clearly defined process for building new generation and investing in existing generation resources. Consequently, no changes to the current PRA construct are warranted for States that regulate utilities on a traditional basis. MISO is however proposing a new structure for jurisdictions that have implemented retail*

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[17] Letter to Dr. Frank Rusco, Director of Natural Resources and Environmental Issues from Johannes P. Pfeifenberger , Samuel A. Newell , Kathleen Spees, and Roger Lueken, Re: Response to U.S. Senators' Capacity Market Questions, May15, 2016, pp. 5-6.

[18] Local Resource Zones 4 and 7

[19] On February 2, 2017, FERC rejected MISO's filing in FERC Docket ER17-284 as not adequately supported. FERC rejected the proposal primarily due to a concern of uncertain, and potentially adverse impacts on price formation due to establishment of two distinct market clearing mechanisms as opposed to a single market-wide clearing process. FERC indicated that typically market-wide clearing processes are more efficient than bifurcated clearing processes.

> *choice and in which no State or local authority has jurisdiction over long-term resource planning."*[20]

In FERC Docket ER17-284 MISO's experts found: "… that MISO's current capacity market design is unlikely to attract and retain sufficient merchant capacity to meet MISO's 1-in-10 reliability standard in the long term." Indeed, it may not need to in LRZs that are comprised of traditionally-regulated, vertically integrated utilities such as LRZ9.

From this standpoint and assuming MISO's current capacity market design is not significantly altered, I would expect that PRA capacity prices for LRZs that are comprised of traditionally-regulated, vertically integrated utilities would generally be below CONE and that the CONE price would only be approached if: 1) mandatory generator retirements due to age or environmental reasons resulted in a short term capacity shortage or, 2) if a large number of regulated utilities were allowed to rely on the PRA and not plan to meet their capacity needs plus reserve margin. Further, I would expect that if the PRA capacity prices approaches or exceeds CONE, it would only be temporary until such time as new capacity was installed through regulated utilities' traditional planning processes.

VIII. ADJUSTED ECONOMIC ANALYSES

Q. EARLIER YOU INDICATED FOUR OBSERVATIONS WITH RESPECT TO THE RESULTS OF ENO'S ECONOMIC ANALYSES, HAVE THE ADVISORS PREPARED A REVISED ANALYSES BASED ON THOSE OBSERVATIONS?

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[20] FERC Docket ER17-284 Proposed Competitive Retail Solution in new Module E-3 and corresponding revisions to existing Tariff sections in Modules A, D, and E-1. P 4,5

A. Yes. For reference my four observations can be summarized as follows:

1. A cautionary note about the inability to compare the results of the cases that assume that no additional DSM with the cases that assume that DSM programs will grow and achieve the Council's 2% DSM Goal

2. ENO's analyses included transmission upgrade investments that were inconsistent with information subsequently provided by ENO

3. Non-levelized results more accurately capture the actual annual revenue requirements associated with each of the cases and are appropriate for assessing the impact of a decision over the 20-year planning

4. The results of the analyses are significantly impacted by the level of ENO's PRA capacity price forecast and the Council may view the cases differently if capacity market price risk is considered.

With respect to the first observation, it is merely informative and there is no need to make any adjustments to ENO's evaluation. With respect to the other observations I will address those changes in tranches such that the adjustments build upon the previous adjustments but, by doing it in two tranches, the effects of the changes can be isolated. The second and third observations are related to corrections to the model and changes in methodology and are included in the first tranche of adjustments. CNO witness Byron S. Watson discusses these changes and presents the results of modifying ENO's analyses in Exhibit No.___(BSW 4). The second tranche of adjustments considers my fourth observation and provides the results of the analyses utilizing an alternate value for the capacity market price. CNO witness Byron S. Watson discusses this change and presents the results of modifying ENO's analyses in Exhibit No.___(BSW 5).

Q. **WHAT IS ALTERNATE VALUE FOR CAPACITY MARKET PRICE THAT WAS UTILIZED IN BSW-5 ?**

A. I requested that Mr. Watson in his analyses utilize a capacity market value equal to the highest clearing price experienced in MISO PRA Zone 9 since the establishment of Zone 9; roughly 16.44 $/MW-day which is equivalent to 6.00 $/kW-yr. ENO's analyses employs a general 2% escalation and, for consistency, I have employed that same escalation with respect to the capacity price beginning in 2017.

Q. TO BE CLEAR, ARE YOU ARE FORECASTING THAT MISO PRA CLEARING PRICES FOR ZONE 9 WILL BE 16.44 $/MW-DAY?

A. No, the 16.44 $/MW-day represents a sensitivity price by which to measure the effects of capacity market price on ENO's analyses. As I indicated, this is equal to the highest clearing price experienced in MISO PRA Zone 9 since the establishment of Zone 9. This clearing price was established for the 2014-2015 planning year. Since that time, the auction clearing prices for in MISO PRA Zone 9 have decreased to the level established in for the 2017-2018 planning year of 1.50 $/MW-day and have yet to exhibit an increasing trend.

Q. PLEASE SUMMARIZE THE RESULTS AND PROVIDE YOUR OBSERVATIONS REGARDING THE RESULTS OF THE ANALYSES WHICH MODIFIES ENO'S

ANALYSES TO ADJUST FOR CORRECTIONS TO THE MODEL AND CHANGES TO A NON-LEVELIZED EVALUATION BASIS ?

A. Tables 4 and 5 present the results of the analyses presented in Exhibit No.___(BSW 4). A review of Table 4, the cases without additional DSM, shows that the CT Alternative is still the favored alternative mathematically, However considering the less than ½ percent difference between the least cost case, the CT Alternative, and the next least cost case, the Transmission Alternative; I believe that on an economic basis that the Council may be indifferent to the two alternatives. The results in Table 5, show that under the non-levelized evaluation method (including corrections), that the 200 MW solar case has edged out the CT alternative as being the least cost alternative among the cases with the Council's DSM Goal. While I have included the results in Tables 4 and 5 in my testimony, I do not believe they are wholly deterministic on what is the best economic option for the Council. The primary reason is that these results still contain ENO's forecast of capacity prices which, as I discussed earlier, are uncertain. To be clear, it is not only the concern of the uncertainty in the capacity price forecasts, but also the magnitude by which the capacity purchases/(sales) dramatically influence the results.

Table 4 – Highly Sensitive Protected Material

Cases Without Additional DSM
ENO's Results Adjusted to a Non-Levelized Basis (including corrections)
$2017MM, NPV(2017 - 2036)

			Case 1	Case 1G	Case 2
1	Variable Cost	[$MM]	[redacted]	[redacted]	[redacted]
2	DSM Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]
3	RICE Alternative Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]
4	CT Alternative Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]
5	Solar Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]
6	Wind Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]
7	Transmission Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]
8	Capacity Purchases/(Sales)	[$MM]	[redacted]	[redacted]	[redacted]
	Total Cost	**[$MM]**	[redacted]	[redacted]	[redacted]
	Variance to Least Cost	**[$MM]**	[redacted]	[redacted]	[redacted]
	% Variance to Least Cost	**%**	[redacted]	[redacted]	[redacted]

Notes:
Case 1 – 128 MW RICE Alternative (2020), 100 MW Solar(2020)
Case 1G – 226 MW CT Alternative (2020), 100 MW Solar(2020)
Case 2 – Transmission Alternative, 100 MW Solar(2020)

Table 5 – Highly Sensitive Protected Material

Cases With Council's 2% DSM Goal
ENO's Results Adjusted to a Non-Levelized Basis (including corrections)
$2017MM, NPV(2017 - 2036)

			Case 3	Case 3G	Case 4A	Case 4B
1	Variable Cost	[$MM]	[redacted]	[redacted]	[redacted]	[redacted]
2	DSM Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]	[redacted]
3	RICE Alternative Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]	[redacted]
4	CT Alternative Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]	[redacted]
5	Solar Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]	[redacted]
6	Wind Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]	[redacted]
7	Transmission Fixed Costs	[$MM]	[redacted]	[redacted]	[redacted]	[redacted]
8	Capacity Purchases/(Sales)	[$MM]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Cost	**[$MM]**	[redacted]	[redacted]	[redacted]	[redacted]
	Variance to Least Cost	**[$MM]**	[redacted]	[redacted]	[redacted]	[redacted]
	% Variance to Least Cost	**%**	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
Case 3 – 128 MW RICE Alternative (2020), 100 MW Solar(2020), Council's 2% DSM Goal
Case 3G – 226 MW CT Alternative (2020), 100 MW Solar(2020) Council's 2% DSM Goal
Case 4A – 200 MW Solar(2020), Council's 2% DSM Goal
Case 4B – 100 MW Solar(2020), 300 MW Wind (2020), Council's 2% DSM Goal

Q. PLEASE SUMMARIZE THE RESULTS AND PROVIDE YOUR OBSERVATIONS REGARDING THE RESULTS OF THE ANALYSES WHICH BUILDS FROM EXHIBIT BSW-5 AND MODIFIES THE CAPACITY PRICE ASSUMPTIONS?

A. Tables 6 and 7 present the results of the analyses presented in Exhibit No.___(BSW 5). These results are important, primarily because they address the concern that capacity markets may not escalate at the rapid pace that ENO has forecasted. These tables in coordination with Tables 4 and 5, seek to identify the impact of capacity price risk on the economic evaluation.

A review of Table 6, the cases without additional DSM, shows that the Transmission Alternative has become the least cost alternative. Regarding the results in Table 7, the analyses shows that the 200 MW solar case is the least cost alternative of the cases modeled with the Council's DSM Goal.

In each of the Tables (Tables 6 and 7). The next best least cost alternative is the RICE Alternative. However, the variances between the least cost and the next best least cost alternative have increased strikingly. Lastly, worthy of note in Tables 6 and 7, is the approximately 1 percent relative difference between the CT Alternative and the RICE Alternative. Suggesting that, if capacity market prices remain at their current levels and the Council elects to proceed with installing a natural gas fired generator at Michoud, that the Council may be economically indifferent between the alternatives.

Table 6 – Highly Sensitive Protected Material

Cases Without Additional DSM
ENO's Results Adjusted to a Non-Levelized Basis with Revised Capacity Pricing
$2017MM, NPV(2017 - 2036)

			Case 1	Case 1G	Case 2
1	Variable Cost	[$MM]	[redacted]		
2	DSM Fixed Costs	[$MM]			
3	RICE Alternative Fixed Costs	[$MM]			
4	CT Alternative Fixed Costs	[$MM]			
5	Solar Fixed Costs	[$MM]			
6	Wind Fixed Costs	[$MM]			
7	Transmission Fixed Costs	[$MM]			
8	Capacity Purchases/(Sales)	[$MM]			
	Total Cost	**[$MM]**			
	Variance to Least Cost	**[$MM]**			
	% Variance to Least Cost	**%**			

Notes:
Case 1 – 128 MW RICE Alternative (2020), 100 MW Solar(2020)
Case 1G – 226 MW CT Alternative (2020), 100 MW Solar(2020)
Case 2 – Transmission Alternative, 100 MW Solar(2020)

Table 7– Highly Sensitive Protected Material

Cases With Council's 2% DSM Goal
ENO's Results Adjusted to a Non-Levelized Basis with Revised Capacity Pricing
$2017MM, NPV(2017 - 2036)

			Case 3	Case 3G	Case 4A	Case 4B
1	Variable Cost	[$MM]	[redacted]			
2	DSM Fixed Costs	[$MM]				
3	RICE Alternative Fixed Costs	[$MM]				
4	CT Alternative Fixed Costs	[$MM]				
5	Solar Fixed Costs	[$MM]				
6	Wind Fixed Costs	[$MM]				
7	Transmission Fixed Costs	[$MM]				
8	Capacity Purchases/(Sales)	[$MM]				
	Total Cost	**[$MM]**				
	Variance to Least Cost	**[$MM]**				
	% Variance to Least Cost	**%**				

Notes:
Case 3 – 128 MW RICE Alternative (2020), 100 MW Solar(2020), Council's 2% DSM Goal
Case 3G – 226 MW CT Alternative (2020), 100 MW Solar(2020) Council's 2% DSM Goal
Case 4A – 200 MW Solar(2020), Council's 2% DSM Goal
Case 4B – 100 MW Solar(2020), 300 MW Wind (2020), Council's 2% DSM Goal

IX. OPTIONS BEFORE THE COUNCIL

Q. BASED ON YOUR ANALYSES WHAT IS THE ECONOMICALLY PREFERRED ALTERNATIVE?

A. Of the cases modeled, the economically preferred alternative appears to be, Case 2, the Transmission Alternative which includes transmission upgrades and 200 MW of solar capacity. A review of my Table 4 shows Case 2 has a net present value that is nearly identical to the next least cost alternative, Case 1G which includes CT Alternative. A review of Table 6, shows the Case 2, the Transmission Alternative, is approximately 9 percent better than the next least cost alternative, Case 1 which includes RICE Alternative. This suggests that the Transmission Alternative compares favorably under a significant range of capacity market price forecasts.

Q. SHOULD THE COUNCIL BASE ITS DECISION IN THIS PROCEEDING SOLELY ON ECONOMICS?

A. No. In my testimony thus far I have reviewed ENO’s application to construct NOPS based on capacity need, economics, and sensitivity to the capacity market. Witness Movish has provided testimony regarding reliability needs with respect to transmission, voltage and regulation support, transmission constructability considerations, the benefits of black start capability, and storm restoration considerations. Witness Watson has provided estimates of the potential rate impacts on customers as a result of the Council’s ultimate decision in this docket. The Council must weigh all these factors when considering a path forward.

Q. ARE YOU AWARE OF ANY OTHER FACTORS, FROM YOUR PERSPECTIVE THAT THE COUNCIL MAY WANT TO CONSIDER WHEN MAKING A DETERMINATION IN THIS DOCKET?

A. Yes. In reviewing the modeling and discovery in this docket I have identified two other areas that may be of interest to the Council in their decision making process: 1) the level of certainty in the capital cost estimates and, 2) several physical parameters of the RICE Alternative that potentially make it operationally more attractive to the Council.

With respect to the capital cost estimates, the estimates for the RICE Alternative and the CT Alternative are fairly certain and based upon negotiated Engineer, Procure and Construct ("EPC") contracts. On the other hand, as Mr. Movish discusses in his testimony, the transmission cost estimates are based on generic high-level cost per mile based estimate rather than a cost estimate based on a specific design.[21] Similar to my concern regarding the capacity market prices, the uncertainty in the transmission capital cost estimates is a concern that should be considered as well.

With respect to physical parameters of the RICE Alternative, I have the following observations. The economic modeling performed by ENO for the RICE Alternative under the reference gas scenario has the unit operating with a [redacted] to [redacted] annual capacity factor; the CT Alternative operates at a higher range with annual capacity factors between [redacted] to [redacted] over the study period. Further, a review of the hourly modeling data shows that the

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[21] ENO Response to Advisors 12-6

CT Alternative, as compared to the RICE Alternative, was dispatched in a less economic operating mode. More precisely, on a relative comparison basis the RICE Alternative had a higher percentage of generation with a generation cost that was below the locational marginal price. While, in MISO a unit operated out of economic dispatch will typically be compensated with make whole payments, the modeling information suggests that the RICE Alternative was more flexible with respect to commitment and dispatch and was a better fit for the generation needs of the region modeled. I believe this is due primarily to the modular nature of the RICE alternative. At any given hour with the RICE Alternative, the facility can be operated with a subset of the seven units producing electricity. That is if MISO only needs 36 MW of generation from NOPS, with the RICE Alternative ENO only needs to turn on two of the engines. On the other hand, the CT alternative would have to be operated at its less efficient practical minimum load of approximately 50% or 110 MW. Accordingly, the RICE Alternative compared to the CT Alternative can more precisely match part load requirements and can most likely be dispatched with the RICE Alternative engines operating at or near their most efficient operating points. Further, at its full load operation, the RICE Alternative has a heat rate that is roughly 18 percent better than the CT Alternative. Accordingly, the RICE Alternative can be expected to have lower per MWh fuel costs as well as being less susceptible to fuel price risk.

Q. YOU INDICATED THAT ENO'S CAPITAL COST ESTIMATES FOR THE NATURAL GAS FIRED NOPS GENERATION ALTERNATIVES ARE BASED ON

EPC CONTRACTS; ARE THE CAPITAL COST ESTIMATES FOR THE NOPS GENERATION ALTERNATIVES REASONABLE?

A. Yes. The estimated total project cost for the 226 MW CT Alternative is $232 million, or approximately $1,026 per kW; total project cost for the 128 MW RICE Alternative is $210 million, or approximately $1,640 per kW. I have reviewed the $/kW installed costs of the RICE Alternative and the CT Alternative and find them to be reasonable.

X. <u>MONITORING PLAN</u>

Q. PLEASE BRIEFLY DESCRIBE THE PROPOSED MONITORING PLAN IF NOPS IS APPROVED .

A. ENO requests that the Council approve a proposed Monitoring Plan under which the Company will report to the Council Advisors on a quarterly basis the status of NOPS. The proposed Monitoring Plan is provided in Exhibit SLM-2 and details the elements of the quarterly progress monitoring reports and includes: summary of status of project schedule; project budget status, project financing details; business issues pertinent to the project; transmission interconnection and Network Resource Interconnection Service (NRIS) status; project safety; environmental compliance; updates in ENO's forecasted cost of natural gas; information regarding material changes in the cost of alternative technology that could serve the same supply role; material changes in the cost to complete the project; material incremental changes in the cost of environmental compliance; and an affirmation as to whether continuing construction of the Project remains in the public interest. The proposed Monitoring plan also requires: that within 30 days of the submission of the quarterly monitoring report, the Advisors will acknowledge receipt of the report, in writing, and provide any questions regarding the report; ENO is to provide to the Advisors informal reports of any significant developments occurring between the more formal quarterly reports; and that ENO arrange for the Advisors to undertake site visits once or twice per year, or as deemed necessary.

Q. DO YOU AGREE WITH THE PROPOSED MONITORING PLAN?

A. Yes, with the condition that upon receipt of the quarterly reports the Advisors should modify, upon coordination and agreement with ENO regarding information that may be readily available and of interest to the Council, the then going forward format and requirements of the quarterly monitoring reports. Provided, of course, that such changes to the format and requirements do not place an undue burden on ENO.

My concern stems from the fact that the quarterly reports will generally contain summary level information. As such, depending on the level of detail that ENO provides, it may not be possible for the Advisors or the Council to fully understand that cause of any change in schedule or cost and/or the ultimate effect of that change on the overall project. While ENO's outline of the reporting elements for the proposed monitoring reports appears, upon initial review, to be sufficient, there may be elements that require adjustment, once the Advisors and the Council are able to review the actual level of detail provided by ENO.

XI. <u>CONCLUSIONS</u>

Q. BASED ON YOUR REVIEW OF THE APPLICATION, WHAT DO YOU RECOMMEND TO THE COUNCIL?

A. Of the cases modeled, the economically preferred alternative appears to be the Transmission Alternative which includes transmission upgrades and 100 MW of solar capacity. Utilizing ENO's forecast of capacity prices, the Transmission Alternative is nearly identical in net present value cost to the next least cost case, which includes the CT Alternative. Under the capacity market price sensitivity, the Transmission Alternative is approximately 9 percent better than the next least cost alternative, suggesting that the Transmission Alternative compares favorably under a significant range of capacity market price forecasts. However, as Mr. Movish describes, the Transmission Alternative includes other risk that must be considered: constructability risk, operational timing risk, and price risk.

Based on load flow analyses the Company has identified a current and immediate need for a solution to mitigate the potential risk of outages in New Orleans. As Mr. Movish has testified, modeling shows that this outage risk mitigation can be accomplished by the Company's Transmission Alternative, CT Alternative, or RICE alternative. However, with respect to the Transmission Alternative, Mr. Movish testifies that reliance on upon the Transmission Alternative poses potentially excessive risk to ENO's customers, and that this Transmission Alternative should not be considered as a realistic alternative until such time as ENO files additional information with the Council. Further, the Company designed

300 MW wind and 200 MW solar resource portfolio alternatives, modeled as delivering power at the Michoud Site, are less likely to mitigate the potential risk of outages identified in the modeling because of the reality of the inadequate ability to site or deliver the power to the load areas identified by the modeling.

If in weighing the risks, the Council elects to proceed with constructing the NOPS unit, I recommend that the Council strongly consider favoring the RICE Alternative. Under the economic analyses modeled either with or without achieving the Council's 2% DSM Goal there is not much difference between the RICE Alternative and the CT Alternative. However, there are operational and physical aspects of the RICE unit that, I believe, cause it to be the preferred alternative. As I have indicated in my testimony the RICE Alternative is a better fit with ENO's load and capability needs especially when considering the Council's 2% DSM Goal. The roughly 18 percent better heat rate of the RICE Alternative, and the flexibility of operation due to the modular nature of the RICE units, can be expected to result in lower per MWh fuel costs and less susceptibility to fuel price risk, as compared to the CT Alternative. Further, I also believe the ability to black start the RICE Alternative in the event that New Orleans becomes disconnected from the regional transmission grid is an advantage that is invaluable and cannot be overlooked.

Lastly, If the Council elects to construct NOPS, ENO's requested monitoring and reporting requirements should be modified as I have identified in my testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

AFFIRMATION

STATE OF COLORADO)
)
COUNTY OF DENVER)

I, Joseph W. Rogers, 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.

Joseph W. Rogers

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

Robin Marie Shaver-LaBarge

NOTARY PUBLIC

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