BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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**

NEW ORLEANS COLD STORAGE & WAREHOUSE CO. LTD.'S
POST-HEARING BRIEF

January 19, 2018

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NEW ORLEANS COLD STORAGE & WAREHOUSE CO. LTD.
POST-HEARING BRIEF

New Orleans Cold Storage & Warehouse Co. Ltd. ("NOCS"), through undersigned counsel, respectfully submits this Post-Hearing Brief, pursuant to Resolution No. R-17-426 in this matter, dated August 10, 2017, as states as follows.

INTRODUCTION AND SUMMARY

Entergy New Orleans, Inc. ("ENO") filed its Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief ("Application") on June 20, 2016 seeking authorization from the Council of the City of New Orleans ("Council" or "City Council") to construct a new 226 MW (summer rating) combustion turbine ("CT") generating unit at its Michoud site in New Orleans East, called the New Orleans Power Station ("NOPS"). NOCS intervened in this proceeding established to analyze ENO's Application. On July 6, 2017, ENO filed its 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")[1] which added an alternative to the NOPS CT consisting of seven Wärtsilä 18 MW reciprocating internal combustion engine ("RICE") sets.[2] For ease of reference, the two NOPS alternatives will be called the "CT Alternative" and the "RICE Alternative", and, collectively, may be referred to as the "NOPS Project". After reviewing the Application, Supplemental Application, pre-filed testimony of the parties, the hearing transcript and evidence admitted into the record, NOCS asserts that the City Council should enter an order setting forth the following findings:

[1] The original Application and the Supplemental Application are sometimes referred to herein, collectively, as the "Application".
[2] The RICE Alternative will provide approximately 128 MW of capacity.

- ENO fell far short of meeting is burden of proving a capacity need for the 226 MW CT Alternative

- It is dubious whether ENO's evidence of a 99 MW capacity shortfall surfacing in 10 years is sufficient to justify the 128 MW RICE Alternative

- The evidence reveals a transmission-related reliability problem, not a generation-related reliability problem

- The record does not contain an analysis of whether the St. Charles Power Station could have provided sufficient reliability benefits to address ENO's needs

- The selection of Combustion Turbine technology (the CT Alternative) is not in the public interest, and even ENO's *own analyses* of the optimal mix of generating resource technologies to fill its purported need indicates that Combined-Cycle Generating Turbine technology is the preferred resource solution

- The selection of the RICE Alternative suffers from the same arbitrary, unsupported foundation as the selection of the CT Alternative, thus, ENO has not shown that the RICE Alternative is in the public interest

- ENO's refusal to conduct a Request for Proposals ("RFP") process to solicit offers from third parties that could have been less expensive than the NOPS Project, denied the City Council the ability to compare the NOPS Project to alternative resources or a mix of resources that could serve the same supply role, on a total production cost basis, and undermines ENO's ability to prove either version of the NOPS Project is the least-cost option for the citizens of New Orleans

- ENO neglected to consider the full range of options to meet any identified need because it didn't use an RFP

- The City Council will initiate a rulemaking to develop RFP rules

- ENO further neglected to consider the full range of options to meet any identified need because it didn't fully analyze a transmission solution

Based upon the evidence in the record, the City Council should find that ENO has not met its burden of proving that the CT Alternative would serve the public convenience and necessity, is in the public interest and, therefore, is prudent. Consequently, the Council should deny the Application to the extent it seeks approval of the CT Alternative. The Council would be justified in denying ENO's Application for approval of the RICE Alternative for the same reasons supporting denial of the approval of the CT Alternative. In the event that the City Council chooses to approve a new generating resource for ENO, however, it should only approve the RICE Alternative, and not the CT Alternative, due to the RICE Alternative's superior attributes. Regardless, should the Council approve either version of the NOPS Project, it should only do so subject to appropriate conditions, and should order the following:

- In the event the Council approves either the CT Alternative or the RICE Alternative, ENO's request for exact cost recovery of such project is rejected since it violates cost-causation principles and constitutes a request for inappropriate single-issue ratemaking

- In the event the Council approves either the CT Alternative or the RICE Alternative, the fixed, non-fuel costs of such project shall be considered along with all of ENO's other costs, expenses, revenues and related factors in the context of the forthcoming Combined Rate Case

- In the event the Council approves either the CT Alternative or the RICE Alternative, the fixed, non-fuel costs associated with the NOPS Project shall be allocated to customer classes on a contribution-to-base-revenues basis, and *not* on a kWh basis

- In the event the Council approves either the CT Alternative or the RICE Alternative, any realignment of the fixed, non-fuel costs associated with the NOPS Project after the Combined Rate Case to any Formula Rate Plan ("FRP") mechanism shall be realigned "inside" the FRP's earnings bandwidth

- The Long Term Service Agreement ("LTSA") costs are fixed and predictable in nature and shall be allocated and collected in the same manner as the other fixed, non-fuel costs of the project

- ENO's actions, including, but not limited to, its selection of resources outside of, and contrary to the results produced by, its optimization process and its decision to bypass testing its self-build NOPS Project against the market through an RFP, justifies placing a cap on the cost of the NOPS Project that may be recovered from ENO's ratepayers to protect them from cost overruns and/or escalations in construction costs due to factors beyond their control

LEGAL STANDARD

ENO bears the burden of proving that the NOPS Project will serve the public convenience and necessity (*i.e.,* it is needed), is in the public interest and would allow it to reliably meet its customers' needs at the lowest reasonable cost and is, therefore, prudent.[3] The Council has acknowledged its obligation in this proceeding is to ensure that "ratepayers receive the most reliable electric and gas service at the lowest reasonable cost."[4]

ARGUMENT

A. Whether ENO's analysis of need is sufficient to justify an investment

1. Whether ENO has demonstrated a capacity need

The first two subissues – *i.e.,* whether ENO has demonstrated a capacity need and whether it has demonstrated a reliability need – essentially ask the same question in slightly different ways. Insufficient generating capacity can impinge a utility's ability to provide reliable service. Likewise, adding generating capacity can often enhance a utility's reliability of service by increasing the utility's resource portfolio. That said, the discussion of whether ENO has demonstrated a capacity need necessarily will overlap with the analysis of whether it has shown a reliability need. Here, ENO's showing falls far short of establishing a need for 226 MW of Combustion Turbine capacity and is dubious with regard to whether ENO needs 128 MW of Reciprocating Internal Combustion Engine capacity.

a. The Evidence does not Support a Need for the CT Alternative

The Council should not approve a new generating resource unless and until the utility

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[3] ENO acknowledges this burden of proof. *See* Supplemental Application, at Prayer for Relief, XLVI. (requesting the Council to find that the NOPS Project "serves the public convenience and necessity and is in the public interest and is therefore prudent.") *See also*, Resolution No. R-17-426, Docket No. UD-16-02, at 13.
[4] Resolution No. R-17-426, Docket No. UD-16-02, dated August 10, 2017, at 8.

meets its burden of proof that such resource is needed. Here, ENO maintains its assertion that the 226 MW CT Alternative "remains the best option for customers,"[5] but ENO has fallen far short of proving that it needs a new 226 MW CT. Between the time of ENO's original Application and its Supplemental Application, its load forecasts declined precipitously. In its original Application, ENO claimed that it had a need for 134 MW of additional capacity by the year 2020 and 205 MW of additional capacity by the year 2030.[6] Conversely, in its Supplemental Application, ENO asserted that it now projects that it will need only 99 MW by 2026 and 248 MW by 2036.[7]

ENO's Supplemental Application states, "As Mr. Cureington discusses, according to the updated load forecast, the Company's projections of customer demand have moderated by an average of 3.4% per year (average of 40 MW per year) compared to the forecast used in the original Application."[8] The updated load forecast eliminated any capacity need in 2020 and pushed back the 99 MW need to 2026. This 40 MW per year reduction in ENO's forecast of its capacity needs translates into a 400 MW drop in load growth over the first 10 years of the planning horizon. Given that ENO's peak load is roughly 1,100 MW, a 400 MW reduction represents an approximate 36% decline in its expected total peak demand.

Under even the most aggressive assumptions, therefore, ENO does not have a need for over 200 MW of new capacity until at least 2036 – ***20 years into the future***.[9] This is simply insufficient to justify ENO's proposal to construct the 226 MW CT Alternative, which would

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[5] Supplemental Application, at XXIV.
[6] *See* Exh. Cureington-5: Public Supplemental and Amending Direct Testimony of Seth E. Cureington ("Public Cureington Supplemental Direct"), dated July 6, 2017, at p. 7, ll. 3-6.
[7] *See id.*, at ll. 8-11.
[8] Supplemental Application, at II.
[9] ENO's updated load forecast estimates it will need approximately 248 MW by the year 2036. *See* Supplemental Application, at XXIV. *See also*, Exh. Cureington-5: Public Cureington Supplemental Direct, at p. 7, ll. 8-11.

cost ratepayers $232 million.[10] Constructing over twice as much capacity as may be needed 10 years down the road is nothing short of overkill. ENO's attempt to establish a need for additional generating capacity hinges on its forecasts of load growth. Load forecasts, like any estimates of the future, are inherently speculative. More importantly, the further out one attempts to estimate future events, such as load growth (or decline), natural gas prices, construction costs and the like, the more speculative and uncertain such estimates become. So, even though ENO projects a 248 MW capacity shortfall in 20 years, that projection is far less certain than ENO's estimate of its capacity need over the next 10 years, which estimate is only 99 MW. Of course, forecasts can err on the high side as well as the low side, but the established trend has shown load growth is declining, not increasing, and there has been no evidence produced showing that this trend will change.

The trend of declining load growth over the last few years was illustrated by Council Advisors' witness, Joseph W. Rogers, P.E., when he testified that ENO's load forecasts supporting the original Application were *lower than* the load forecasts supporting its 2015 Integrated Resource Plan ("IRP") – in which ENO selected the CT Alternative – and the load forecasts supporting the Supplemental Application were *lower than* the load forecasts supporting the original Application.[11] Mr. Rogers also explained that, as low as they are, ENO's load forecasts are likely *overstated* since they do not take into account "reductions in the load

[10] *See* Supplemental Application, at VI. ENO's original Application estimated the cost to construct the CT Alternative would be $216 million.

[11] *See* Exh. Rogers-2: HSPM Direct Testimony and Exhibits of Joseph W. Rogers ("HSPM Rogers Direct"), dated November 20, 2017 (under seal), at p. 6, l. 7 – p. 7, l. 3. Mr. Rogers went so far as to say that ENO's load forecast used for the original Application was "***dramatically different*** than the forecast used in the Final 2015 IRP forecast." Exh. Rogers-1: Public Direct Testimony and Exhibits of Joseph W. Rogers ("Public Rogers Direct"), dated November 20, 2017, at p. 20, ll. 7-9. (Emphasis and bolding added).

requirements for future [demand side management ("DSM")] programs."[12] ENO has committed to adding 100 MW of renewable resources to its portfolio.[13] This commitment, combined with the Council's 2% DSM Goal, and if realized, could wipe out the entirety of the 99 MW shortfall expected by 2026.

Air Products' witness, Maurice Brubaker, also found that ENO has not shown a capacity need for the 226 MW CT Alternative. He states, "There is not an immediate need for that amount [226 MW] of capacity."[14]

Meanwhile, the size and estimated cost of ENO's CT Alternative have grown over this same time frame. In its 2015 IRP, ENO estimated that it needed to construct a 194 MW CT.[15] When the original Application was filed, however, ENO proposed a 226 MW CT, which was expected to cost $216 million. As Mr. Rogers testified, the increase in the size of the selected CT Alternative was *not* the result of ENO's optimization program (the AURORA Capacity Expansion Model); rather ENO simply switched the size of the CT Alternative from 194 MW to 250 MW[16] while running the Stakeholder Input Case in connection with the Final 2015 IRP.[17]

ENO's arbitrary, unsupported increase in the size of the CT Alternative should be rejected. Compounding the inequities caused by the arbitrary increase in the size of the CT Alternative was a subsequent increase in the cost. As of the filing of the Supplemental

[12] Exh. Rogers-1: Public Rogers Direct, at p. 10, ll. 3-5.
[13] *See* Exh. Rogers-1: Public Rogers Direct, at p. 20, ll. 14-15. *See also*, Exh. Rice-3: Supplemental and Amending Direct Testimony and Exhibits of Charles Rice, Jr. ("Rice Supplemental Direct"), dated July 6, 2017, at p. 20, ll. 1-10 and p. 21, ll. 15-19.
[14] *See* Exh. Brubaker-2: Public Additional Direct Testimony and Exhibits of Maurice Brubaker ("Public Brubaker Additional Direct"), dated October 16, 2017, at p. 6, ll. 10-12.
[15] *See* Exh. Rogers-1: Public Rogers Direct, at p. 13, l. 15 – p. 14, l. 1-3. *See also*, Resolution No. R-17-426, Docket No. UD-16-02, at p. 7 (whereat the Council quotes its previous Resolution No. R-16-263 (the Show Cause Order) expressing its concern over the inadequate explanation for the significant increase in the size of the CT Alternative).
[16] 250 MW is the nominal rating of the CT Alternative, which produces a summer rating of 226 MW.
[17] *See* Exh. Rogers-1: Public Rogers Direct, at p. 16, ll. 3-13.

Application, the cost estimate for the CT Alternative had swollen to $232 million.[18] Building the increasingly expensive 226 MW CT Alternative to meet a 99 MW need that is not expected to surface for another 10 years, when faced with declining load growth forecasts, would not be prudent.

b. Whether the Evidence Supports a Purported Capacity Need for the RICE Alternative is Dubious

ENO's load forecasts show an expected 99 MW need occurring in 2026. On the surface, this need could support a certification of the 128 MW RICE Alternative. As explained above in the discussion regarding the CT Alternative, however, the evidence supporting the capacity need of 99 MW is weak at best. Load forecasts are declining. ENO has committed to adding 100 MW of renewable resources. The City Council has established a 2% DSM Goal. The Transmission Alternative, as explained below, could satisfy the reliability problem (and is more cost effective than the RICE Alternative). That said, and even if the Council finds that the evidence supports a capacity need for the RICE Alternative, establishing a capacity need is only part of the equation. A utility must also show that it has selected the least cost option for meeting the anticipated need.

2. Whether ENO has demonstrated a reliability need

ENO has not demonstrated a generation-related reliability need. The evidence does not support a finding that, without either the CT Alternative or RICE Alternative, ENO will have insufficient generating capacity to meet its customers' demand. As mentioned, ENO's load growth forecasts have been declining. The most current forecast indicates a need for 99 MW in 2026. A 99 MW shortfall in 10 years does not support spending $200+ million now. ENO can

[18] *See* Supplemental Application, at VI. *See also*, Resolution No. R-17-426, Docket No. UD-16-02, at 11 (noting that the cost estimate of the CT Alternative increased $16 million from the time of the original Application to the filing of the Supplemental Application).

purchase capacity – if needed – in the capacity market operated by the Midcontinent Independent System Operator, Inc. ("MISO") for the short term, while it monitors load forecasts to see if they rebound.[19] At best, ENO has only shown a transmission-related reliability need. Even then, ENO's analysis is woefully inadequate to show that building generating capacity is the most reasonable and cost-effective method of addressing the transmission reliability need.

Council Advisors' witness, Joseph A. Vumbaco, P.E., testified, among other things, that: (a) ENO's transmission system is currently at risk of cascading outages and is in violation of applicable reliability standards promulgated by the North American Electric Reliability Corporation ("NERC"), the federal entity that establishes mandatory standards regarding reliability of the bulk electrical grid, and (b) ENO has not shown that either the CT Alternative or the RICE Alternative are economically justified, as compared to constructing near-term transmission upgrades (*i.e.,* the "Transmission Alternative"),[20] but ENO cannot provide a date by which it could feasibly construct the required upgrades. The Council's Advisors, therefore, recognize that ENO doesn't face a *generation* reliability problem; it faces a *transmission* reliability problem.[21] The Advisors testify that the Transmission Alternative is ***economically more attractive*** than either the CT Alternative or the RICE Alternative, but do not recommend it due to the uncertainty of when it might be completed, coupled with some uncertainty regarding

[19] Council Advisors' witness, Mr. Rogers, agrees that ENO should "rely on the MISO [capacity] markets to meet limited short-term differences in resources and loads." Exh. Rogers-1: Public Rogers Direct, at p. 32, ll. 4-7. *See also, id.*, at p. 34, ll. 1-12.
[20] Mr. Rogers points out that the Transmission Alternative consists of certain upgrades to ENO's transmission system together with the addition of 100 MW of solar capacity, and that both the CT Alternative and RICE Alternative cases also include the addition of 100 MW of solar capacity. *See* Exh. Rogers-1: Public Rogers Direct, at p. 25, ll. 16-19 and p. 45, ll. 1-11. NOCS notes that the reference to "200 MW" of solar capacity assumed for the analysis of the Transmission Alternative on p. 45 of Mr. Rogers testimony appears to be a typographical error.
[21] *See, e.g.,* Exh. Movish-1: Direct Testimony and Exhibits of Philip J. Movish ("Movish Direct"), dated November 20, 2017, at p. 23, l. 14 – p. 24, l. 2 (stating that the retirement of ENO's Michoud units has put ENO's system "at risk of transmission reliability issues").

the cost estimates for such upgrades.[22] Mr. Vumbaco opines that, of the two generation alternatives, the RICE Alternative presents less risk and provides more benefits than the CT Alternative.[23] The Advisors' testimony and evidence, therefore, show that the CT Alternative is a solution in search of a problem.

Similarly, Air Products' witness, James R. Dauphinais, testified regarding reliability issues and concludes that ENO has not reasonably demonstrated there is a reliability need for the NOPS Project. ENO estimates that, should the NOPS Project not be constructed, it would have to build roughly $66 million worth of transmission upgrades.[24] ENO has not identified, however, when such transmission upgrades will be necessary.[25] Mr. Dauphinais notes that none of the upgrades identified by ENO as allegedly "necessary" are contained in relevant MISO planning documents.[26] Transmission upgrades must go through an approval process with MISO before they may be constructed. Mr. Dauphinais concludes, therefore, that, "The fact that the projects have not been identified in the MISO MTEP process suggests they may not be needed until several years from now, and the final list of projects may be much shorter and/or of lower cost once an effort is made to refine them."[27]

The evidence in the record shows ENO faces a transmission reliability problem and that a transmission solution (the Transmission Alternative) is the most cost-effective means of solving that problem. NOCS agrees with the Council's Advisors that the "Do Nothing Option" is not

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[22] *See* Exh. Vumbaco-1: Direct Testimony and Exhibits of Joseph A. Vumbaco ("Vumbaco Direct"), dated November 20, 2017, at p. 7, l. 9 – p. 8, l.6.
[23] *See id.*, at p. 27, l. 17 – p. 28, l. 17.
[24] *See* Exh. Duphinais-1: Direct Testimony and Exhibits of James R. Dauphinais ("Dauphinais Direct"), dated January 6, 2017, at p. 4, ll. 11-21. This figure must be examined in light of ENO's claim that it would need to build approximately *$57 million* worth of transmission upgrades if the NOPS Project is not built. *See* Exh. C. Long-2: Supplemental and Amending Direct Testimony and Exhibits of Charles W. Long ("C. Long Supplemental Direct"), dated July 6, 2017, at p. 11, Table 1.
[25] *See* Exh. Duphinais-1: Dauphinais Direct, at p. 4, ll. 22-24.

sustainable. So, the Council must decide the best course of action to address the identified transmission-related reliability problem. In addressing this problem, the Council should consider how the problem arose.

The current transmission-related reliability problem did not spring up unexpectedly; rather, it is the consequence of a string of ENO's decisions and actions. First, ENO retired its Michoud units, representing approximately 781 MW of generating capacity in the City.[28] Next, ENO acknowledges that it was supposed to, but didn't, purchase a portion (roughly 20% of the capacity) of a new Combined Cycle Generating Turbine ("CCGT") to be constructed by its affiliate, Entergy Louisiana, LLC ("ELL"), near New Orleans through a Purchased Power Agreement ("PPA"). This CCGT, called the St. Charles Power Station (sometimes referred to as "SCPS"), was approved by the Louisiana Public Service Commission in December 2016 and is currently under construction. The SCPS project is located in Montz, Louisiana, which is on the East Bank of the Mississippi River in St. Charles Parish, and, as such, is expected to provide reliability benefits to ENO's customers.[29] ENO also admits that it changed its plans to purchase from ELL 20% of the capacity of Power Blocks 3 and 4 of the Union Power Station ("UPS") and the planned PPA with ELL for a portion of the capacity from the St. Charles Power Station CCGT, to its purchase of the entirety of Power Block 1 of UPS.[30]

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[26] *See id.*, at p. 5, ll. 1-14.
[27] *Id.*, at p. 5, ll. 18-21.
[28] *See* Supplemental Application, at XX. and XXI. *See also*, Exh. Cureington-5: Public Cureington Supplemental Direct, at p. 17, l. 17 – p. 18, l. 10.
[29] *See* Exh. Cureington-5: Public Cureington Supplemental Direct, at p. 19, l. 15 – p. 20, l. 5 (noting that the SCPS project is anticipated to provide reliability benefits to ENO).
[30] *See* ENO's Integrated Resource Plan ("IRP") (2015), at pp. 50-51. See also, *See* Exh. Rogers-1: Public Rogers Direct, at p. 19, ll. 15-18.

The final cost to construct the St. Charles Power Station CCGT is approximately $886/kW.[31] Consequently, had ENO followed through and entered the PPA with ELL for 226 MW of the St. Charles Power Station (in lieu of the 226 MW CT Alternative), it would have cost just over $200 million,[32] which is ***$10 million less*** than the current 128 MW RICE Alternative and over ***$30 million less*** than the 226 MW CT Alternative.[33] Similarly, had ENO contracted for 128 MW of the St. Charles Power Station (in lieu of the 128 MW RICE Alternative), it would have cost just over $113 million,[34] which is ***$96 million less*** than the current RICE Alternative and over ***$118 million less*** than the CT Alternative. These large price differences are caused by the variance in the unit costs of the various options. The unit costs of the RICE and CT Alternatives far exceed the unit cost of the St. Charles Power Station. The RICE Alternative is estimated to cost $1,640/kW,[35] and the CT Alternative is estimated to cost $1,026/kW,[36] as compared to the $886/kW price tag of the St. Charles Power Station CCGT.

The record does not contain an analysis of whether the PPA with ELL for 20% of the St. Charles Power Station's capacity could have provided sufficient reliability benefits to fully address ENO's needs. ENO's disregard of the St. Charles Power Station as a potential resource option undermines any assertion that it faces a reliability need, or, if it does have a reliability need, that the NOPS Project is the lowest reasonable cost solution to meet that need, especially given the substantially lower unit cost of the St. Charles Power Station, its close proximity to

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[31] *See* LPSC Order No. U-33770, dated December 14, 2016, 2016 WL 7337362, approving the construction of the St. Charles Power Station, at p. 8. *See also*, Exh. Cureington-5: Public Cureington Supplemental Direct, at p. 19, l. 15 – p. 20, l. 5 (stating that SCPS is a 980 MW CCGT that is estimated to cost $870 million). 980 MW = 980,000 kW. $870,000,000 ÷ 980,000 kW = $887.75/kW.
[32] $886/kW x 226,000 kW = $200,236,000.
[33] ENO's IRP stated that it planned to purchase 229 MW from the "Amite South CCGT", which ultimately was called the St. Charles Power Station. *See* ENO IRP (2015), at p. 51.
[34] $886/kW x 128,000 kW = $113,408,000.

New Orleans, and the prior agreement affording ENO the right to purchase capacity from that project.

ENO's decisions to retire the Michoud units, to purchase the entirety of Power Block 1 of UPS, and to back out of the agreement to purchase 20% of SCPS occurred over the same time frame (*i.e.*, 2014-2016) as the decision to select the CT Alternative.[37] ENO should have presented to the City Council a comprehensive analysis, complete with cost/benefit studies, of its options to reliably meet its customers' demand at the lowest reasonable cost, which would have compared, at a minimum, (a) retiring vs. continuing to operate the Michoud units, (b) purchasing 100% of Power Block 1 of UPS vs. going through with the plan to purchase 20% of Power Blocks 3 and 4 from ELL, and (c) constructing the CT Alternative vs. purchasing 20% of the St. Charles Power Station project from its affiliate, ELL. Rather than presenting this type of comprehensive, integrated analysis, ENO presented piecemeal applications, which deprived the Council of the ability to assess all options in conjunction with each other, and then claimed that New Orleans faces a transmission reliability crisis mandating a $232 million generating project, upon which it will earn a rate of return for decades.

Based upon the evidence in the record, a Council decision to reject ENO's Application to construct additional generation capacity in its service territory and to order ENO, instead, to show when the Transmission Alternative may be accomplished and at what cost would be well-supported. The Advisors point out that the Transmission Alternative is economically more attractive than either the CT Alternative or the RICE Alternative, but do not recommend it due to

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[35] *See* Exh. Cureington-5: Public Cureington Supplemental Direct, at p. 3, ll. 6-9. *See also,* Exh. Rogers-1: Public Rogers Direct, at p. 5, l. 11 – p. 6, l. 3.
[36] *See* Exh. Rogers-1: Public Rogers Direct, at p. 4, l. 13 – p. 5, l. 3.

the uncertainty of when it might be completed and the final cost of such upgrades.[38] NOCS acknowledges, however, that the Council may find there is sufficient value in the ancillary benefits that may accrue from constructing generating capacity within the City – which currently lacks any generation – to justify adding generating capacity. Should the Council decide that new generating capacity inside the City would serve the public convenience and necessity, is in the public interest, and is prudent, it should approve the RICE Alternative, not the CT Alternative, as more fully discussed, below, and should place conditions on its approval.

B. Whether ENO's choice of technology(ies) is in the public interest

1. Whether ENO's selection of a CT unit is in the public interest

Based upon the foregoing discussion, including, particularly, ENO's inability to show a need for 226 MW of additional generating capacity in the foreseeable future, the CT Alternative is not in the public interest. Even if ENO could show a need in the foreseeable future for 226 MW of additional generating capacity (which it can't), the question still remains of whether Combustion Turbine technology is the best, most economical solution to meet such capacity need. Here, while ENO argues there are ancillary benefits to constructing the over-sized CT Alternative, such as ostensibly eliminating all North American Electric Reliability Corporation ("NERC") transmission reliability issues,[39] it neglects to quantify any such ancillary benefits or

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[37] *See* Exh. Rogers-1: Public Rogers Direct, at p. 19, ll. 5-9 (explaining that the Final 2015 IRP process took "more than 20 months beginning in the first half of 2014 and culminating in the filing of the Final 2015 IRP in February 2016.").

[38] *See, e.g.*, Exh. Vumbaco-1: Vumbaco Direct, at p. 21, ll. 12-20, and p. 23, ll. 1-14. The Advisors note, however, that the Transmission Alternative option would not provide local generation or black-start capability and may not be able to be completed in time to avoid NERC violations.

[39] *See* Supplemental Application, XXV. ENO admits that the RICE Alternative "will also provide many of the same benefits as the larger CT, albeit to a lesser degree because it is 100 MW smaller." Supplemental Application, at XXVII.

explain the relative value of the ancillary benefits to be provided by the CT Alternative as compared to the ancillary benefits to be provided by the RICE Alternative.

More importantly, the choice of Combustion Turbine technology is not supported by ENO's *own analyses* of the optimal mix of generating resource technologies to fill its purported need. In connection with its 2015 IRP, through which ENO selected the CT Alternative, it utilized the AURORA Capacity Expansion Model to assess resource options. The AURORA Capacity Expansion Model "utilizes a linear optimization process and iterative calculations to find the optimal combination of resources to meet projected load-serving needs" for electric utilities.[40] In ***none*** of the four scenarios ENO ran through its AURORA model in connection with the 2015 IRP did the model select a CT resource.[41] Instead, the AURORA model selected a CCGT resource in three of the four scenarios and a combination of solar and wind resources in the fourth scenario.[42] ENO's own AURORA optimization model results, therefore, cast serious doubt on its selection of the CT Alternative.[43]

Considering the combination of factors discussed herein weighing against the selection of the CT Alternative, including, but not limited to, the fact that it was neither identified as an optimal technology by the AURORA model, nor selected as a result of the IRP process or an RFP process, its excessive size and cost, and its disadvantages as compared to the RICE Alternative, discussed below, leads to the inescapable conclusion that ENO cannot prove the CT Alternative is in the public interest.

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[40] Exh. Rogers-1: Public Rogers Direct, at p. 14, ll. 14-16.
[41] *See* Exh. Rogers-1: Public Rogers Direct, at p. 14, l. 16 – p. 15, l. 3.
[42] *Id.*
[43] The AURORA model results pointing to CCGT technology as the optimal resource to meet ENO's needs also invites further scrutiny of ENO's decision to forego purchasing a portion of the capacity of the St. Charles Power Station CCGT being constructed by its affiliate, ELL.

2. Whether ENO's selection of a RICE unit is in the public interest

The same infirmities infecting ENO's selection of the CT Alternative, discussed above, plague its decision to seek certification of the RICE Alternative. For example, and as discussed more thoroughly below, ENO's failure to conduct an RFP when selecting generating resources to meet its claimed capacity need likewise undermines its attempt to show that the RICE Alternative is in the public interest. Also, and like the selection of the CT Alternative, ENO's selection of the RICE Alternative was not the result of the optimization process in the 2015 IRP.[44] The selection of the RICE Alternative, therefore, suffers from the same arbitrary, unsupported foundation as the selection of the CT Alternative. A utility's decision-making process must be prudent. Here, the Council would be justified in rejecting ENO's request to certify the RICE Alternative due to ENO's flawed decision-making in the selection of the RICE Alternative, which was untethered from any reasonable resource selection methodology such as identification through the 2015 IRP, vetting through an open and fair RFP, or as a result of an optimization process. ENO's manner of selecting the NOPS Project thumbs its nose at the Council's mandated IRP process and flies in the face of prudent resource planning principles.[45]

Regardless, however, NOCS understands that the City Council may wish to approve new generating capacity within the City of New Orleans to enhance the reliability of the transmission system serving ENO's customers. In the event that this Council approves any new generating

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[44] *See* Exh. Rogers-1: Public Rogers Direct, at p. 16, l. 18 – p. 17, l. 16. Mr. Rogers explains that the 128 MW RICE Alternative was apparently selected as a result of ENO's request to WorleyParsons to study peaking units sized between 100 MW and 150 MW. *See also*, Exh. J. Long-5: Public Supplemental and Amending Direct Testimony of Jonathan E. Long ("Public J. Long Supplemental Direct"), dated July 6, 2017, at p. 6, l. 11 – p. 7, l. 2.

[45] As Mr. Rogers points out, the 2015 IRP identified CCGT technology as the most economical resource to meet ENO's needs using the AURORA optimization model in three of four scenarios, and solar and wind resources in the

resource for ENO, it should only approve the RICE Alternative, and not the CT Alternative, for the reasons set forth herein.

From a cost perspective, the RICE Alternative is less expensive than the CT Alternative. ENO estimates the cost for the RICE Alternative to be $210 million as opposed to $232 million for the CT Alternative.[46] Although the RICE Alternative is less expensive than the CT Alternative, and as NOCS illustrates herein, ENO chose to forego generating resource alternatives that were even less expensive than the RICE Alternative.[47] This fact should not be lost on the Council when addressing cost recovery for the NOPS Project. In light of the evidence surrounding ENO's actions in selecting the NOPS Project, including, but not limited to, ENO's decision to bypass testing this self-build project against the market through an RFP, placing a cap on the cost of the NOPS Project that may be recovered from ENO's ratepayers to protect them from cost overruns and/or escalations in construction costs due to factors beyond their control would be prudent. ENO claims that the Engineering, Procurement and Construction ("EPC") contract it has entered for the construction of the CT Alternative is a "fixed-price, date-certain form of contract[]"[48] and that the construction contract for the RICE Alternative contains "schedule incentives and liquidated damages" capped at a percentage of the EPC contract value, with "overall monetary liability" also capped at a percentage of the EPC contract value.[49] Given these restrictions on the contract prices for constructing either version of the NOPS Project, ENO

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fourth scenario. The optimization model *did not select* any CT resource or RICE resource. *See* Exh. Rogers-1: Public Rogers Direct, at p. 14, l. 16 – p. 15, l. 3.

[46] *See* Supplemental Application, at VI. and VII.

[47] As one example, ENO backed out of its agreement to purchase approximately 20% (229 MW) of its affiliate's St. Charles Power Station CCGT project, which costs only $886/kW, as compared to the price tag for the RICE Alternative of $1,640/kW.

[48] Exh. J. Long-5: Public J. Long Supplemental Direct, at p. 20, ll. 20-22.

[49] *Id.*, at p. 21, ll. 3-5.

should not be opposed to a cap on cost recovery in the amount of such caps currently included in the EPC contracts.

From an operational standpoint, the RICE Alternative possesses certain attributes that are superior to those of the CT Alternative. To begin with, the RICE Alternative is more flexible from a dispatch perspective. As Mr. Rogers testifies, the modular nature of the RICE Alternative (*i.e.,* seven RICE units, which can be operated individually or as a group) would allow ENO to scale the output of the plant to meet changing load conditions.[50] The CT Alternative, on the other hand, cannot operate at a level lower than at least 50% of its capacity.[51] The scalability of the RICE Alternative contributes to the more economic dispatch of the RICE Alternative as compared to the CT Alternative.[52] The RICE Alternative also possesses a better heat rate (*i.e.,* efficiency rating) than the CT Alternative.[53] Additionally, the RICE Alternative will include black-start capability (*i.e.,* the ability to start after an outage – including storm-related outages – without the aid of outside generation),[54] while the CT Alternative lacks this feature. Further, the RICE Alternative will utilize far less groundwater than the CT Alternative[55] and will provide greater ability to support renewable resources than the CT Alternative.[56] Finally, ENO anticipates that, were the Council to approve the RICE Alternative, and although it would be

[50] *See* Exh. Rogers-1: Public Rogers Direct, at p.46, l. 15 – p. 47, l. 11.
[51] *See* Exh. Rogers-1: Public Rogers Direct, at p. 47, ll. 11-12.
[52] As Mr. Rogers explains, ENO's economic modeling of the RICE Alternative showed that it produced "a higher percentage of generation with a generation cost that was below the locational marginal price" than did the CT Alternative. Exh. Rogers-1: Public Rogers Direct, at p.46, l. 15 – p. 47, l. 4. In other words, a greater portion of the output of the RICE Alternative was produced at a lower price than that of the CT Alternative.
[53] *See* Exh. Rogers-1: Public Rogers Direct, at p. 47, ll. 15-18.
[54] *See* Supplemental Application, at XI. and XXVI. *See also*, Exh. J. Long-5: Public J. Long Supplemental Direct, at p. 13, ll. 5-19; and Resolution No. R-17-426, at 11.
[55] *See* Supplemental Application, at XI. and XXVI. *See also*, Exh. Rice-3: Rice Supplemental Direct, at p. 12, ll. 16-20; Exh. J. Long-5: Public J. Long Supplemental Direct, p. 11, l. 20 – p. 12, l. 14; and Resolution No. R-17-426, at 11.
[56] *See* Supplemental Application, at XI. and XXVI. *See also*, Exh. Rice-3: Rice Supplemental Direct, at p. 10, ll. 5-9; Exh. J. Long-5: Public J. Long Supplemental Direct, at p. 12, l. 16 – p. 13, l. 3.

smaller than the CT Alternative, it would resolve nearly all transmission reliability concerns such that "there would only be very minor overloading on the transmission system in planning year 2027."[57]

3. Whether ENO appropriately considered a full range of options to meet the identified need

a. ENO neglected to consider the full range of options to meet any identified need because it didn't use an RFP

The Council should find that ENO neglected to consider the full range of options to meet the purported need for capacity because, in addition to the arbitrary and unsupported method ENO followed in selecting the CT Alternative (which method contradicted its own AURORA model results) discussed previously, ENO selected the self-build CT Alternative without testing the market. A Request for Proposals ("RFP") process is an appropriate way to test the market to determine the full range of credible options when a utility needs additional capacity. Even assuming the evidence showed a need, ENO's process for selecting the NOPS Project was so flawed, and excluded so many potentially more economic resources, that ENO cannot show that it selected the least costly option. Prudence dictates a comparison of a selected resource to alternatives as part of the showing of least cost.

ENO's affiliates, Entergy Gulf States Louisiana, L.L.C. ("EGSL") and Entergy Louisiana, LLC ("ELL")[58] have been required since 2002 under the orders and regulations of the

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[57] Supplemental Application, at XXVIII. In fact, ENO states that, "[T]here is a possibility that the [RICE Alternative] would satisfy all NERC reliability criteria." *Id. See also*, Exh. C. Long-2: C. Long Supplemental Direct, at p. 6, l. 4 – p. 7, l. 2, p. 13, ll. 1-17, and p. 27, l. 20 – p. 28, l. 5.

[58] Effective 2015, EGSL and ELL merged. *See* LPSC Order No. U-33244. The surviving entity is also named Entergy Louisiana, LLC.

Louisiana Public Service Commission ("LPSC")[59] – the regulatory agency with jurisdiction over electric utilities operating in the state of Louisiana outside of New Orleans – to conduct formal RFPs when acquiring or constructing new long-term generating resources. The LPSC considers the results of the RFP process as one of the crucial factors in determining whether to certify EGSL's or ELL's proposed long-term resource as being in the public interest. Although the LPSC does not have jurisdiction over ENO and the City Council's rules and regulations may – and do – differ from that of the LPSC's, the LPSC's orders, rules and regulations are instructive.

Further, and regardless of the LPSC's rules, *any* electric public utility – including ENO – must show that its actions are prudent and reasonable. In *Gulf States Utilities Co. v. Louisiana Public Service Commission*,[60] the Louisiana Supreme Court examined the LPSC's order denying Gulf States Utilities Co. (predecessor to EGSL) the ability to recover from its customers $1.3 billion of investment in the River Bend Nuclear Generating Facility ("River Bend"). The Court held,

> [A regulator] must balance the interest of the ratepayers in the lowest possible rates, against that of the utility and its investors, who understandably desire the highest possible rates. *Morehouse National Gas Co. v. Louisiana Public Service Comm'n*, 245 La. 983, 162 So.2d 334 (1964). Although there is no single formulation sufficient to express constitutional, statutory, or judicially derived standards for determining how much of a utility's investment in a particular plant should be included within its rate base, *see Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1944), one of the principles used by ratemaking bodies and courts to make such a determination is the prudent investment standard. That standard "essentially applies an analog of the common law negligence standard for determining whether to exclude value from rate base." *Appeal of Conservation Law Foundation*, 127 N.H. 606, 507 A.2d 652, 673 (1986). **That is, the utility must demonstrate that it "went**

[59] *See collectively*, LPSC General Order dated April 10, 2002 (Docket No. R-26172); amended by General Order dated February 16, 2004 (Docket No. R-26172, Sub Docket A), General Order dated November 3, 2006 (Docket No. R-26172, Subdocket B), General Order dated April 26, 2007 (Docket No. R-28376), General Order dated October 29, 2008 (Docket No. R-26172, Subdocket C and R-30517) **("Market Based Mechanism Order").**
[60] *Gulf States Utilities Co. v. Louisiana Public Service Commission*, 578 So.2d 71 (La. 1991).

through a reasonable decision making process to arrive at a course of action and, given the facts as they were or should have been known at the time, responded in a reasonable manner." *Re Cambridge Electric Light Co.*, 86 P.U.R.4th 574 (Mass.D.P.U. 1987).[61]

Similarly, the Fourth Circuit Court of Appeal held, on review of one of the City Council's most monumental orders (denying ENO cost recovery of $135 million associated with the Grand Gulf Nuclear Generating Facility), that, "A public utility is a monopoly which exists in a non-competitive market. Because a utility enjoys such a great economic advantage, it owes a high duty of prudence to its customers in decision making, operation and management. ... Therefore the pass through of imprudent costs to ratepayers/consumers is prohibited by law."[62]

The above-stated precepts apply not only to the prudent investment rule but to prudence in general. As the Louisiana Supreme Court held, "That is, the focus in a prudence inquiry is not whether a decision produced a favorable or unfavorable result, but rather, whether the process leading to the decision was a logical one, and **whether the utility company reasonably relied on information and planning techniques known or knowable at the time.**"[63] The LPSC's consultants reviewed Gulf States' analysis of alternatives to River Bend at the time it made the decision to restart construction of the unit (following the Three Mile Island disaster), and found "virtually no analysis was made of the economic consequences of the options available in 1979."[64] Conversely, the LPSC's consultants analyzed the cost of constructing a lignite plant as compared to the cost to complete River Bend and concluded building a lignite plant would have

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[61] *Gulf States*, 578 So.2d at 84-84. (Footnotes omitted)(Bolding added).
[62] *Alliance for Affordable Energy, Inc. v. Council of the City of New Orleans*, 578 So.2d 949, 973-74 (La.App. 4 Cir. 1991), *vacated after consent decree* at 588 So.2d 89 (La. 1991). *See also, South Central Bell Telephone v. Louisiana Public Service Commission*, 352 So.2d 964, 972-73 (La. 1977), *cert. denied*, 437 U.S. 911, 98 S.Ct. 3103, 57 L.Ed.2d 1142 (1978) (finding that "ratepayers should not bear the burden of a utility's imprudence.").
[63] *Id.*, 578 So.2d at 85. (Internal citation omitted)(Bolding added).
[64] *Id.*, 578 So.2d at 86.

been the more economical option.[65] The Court affirmed the LPSC's finding of imprudence on Gulf States' part due to its failure to analyze generation alternatives at the time the decision to restart construction of River Bend was made.[66]

In order to show that the NOPS Project is prudent, therefore, ENO must show that its *decision-making in electing to construct the NOPS Project* was prudent and reasonable. ENO can only meet this burden by showing that NOPS is the least-cost option among alternatives. Without a comparison of NOPS to all available alternatives (which would have been possible had an RFP been performed), ENO lacks sufficient evidence to show that NOPS is the least-cost alternative for its customers. As previously discussed, ENO's constrained analysis pigeonholed new-build CT technology in general, and the NOPS Project in particular, as the preferred choice to meet its purported need rather than comparing the total relative production costs of the NOPS Project to other technologies, such as CCGT technology or Combined Heat and Power ("CHP") technology. The most reliable way to get real-world total production costs to compare to the NOPS Project – as opposed to assumptions or projections of costs – is to solicit bids in an RFP. Since ENO did not conduct an RFP when selecting the NOPS Project, its Application is fatally flawed and should be denied.

ENO is well-familiar with the formal RFPs conducted by EGSL and ELL, as well as those conducted by its services affiliate, Entergy Services, Inc. ("ESI") on behalf of the Entergy Operating Companies, ***including*** ENO.[67] More importantly, ENO, ***itself***, recently conducted a

[65] *Id.*, 578 So.2d at 88-89.
[66] *Id.*, 578 So.2d at 94.
[67] *See* excerpts of Entergy's Summer 2008 RFP, at Sec. 1.1 ("Entergy Services, Inc. ("ESI"), acting as agent for one or more of the Entergy Operating Companies, is issuing this Summer 2008 Request for Proposals… and fn. 1 identifying ENO as one of those Entergy Operating Companies).

formal RFP for renewable resources.[68] In fact, since the first iteration of the LPSC's MBMO, adopted in 2002, Entergy Corporation, through and with its subsidiaries, including ESI, has conducted over a dozen formal RFPs for generating resources. ENO's experience with formal RFPs conducted on its behalf by its affiliate, ESI, and the recently-conducted renewables RFP leave it without an excuse for not conducting a formal RFP before electing to construct the NOPS Project. The decision to construct the $200+ million NOPS Project should have included a vetting of available alternatives to this self-build project, which could only truly be produced through an open and fair RFP process.

b. The City Council should initiate a rulemaking to develop RFP rules

NOCS respectfully requests the City Council to initiate a rulemaking to develop its own RFP rules. The RFP rules should be based upon the LPSC's Market Based Mechanism Order ("MBMO"), with some modifications. ENO's affiliates have included discriminatory provisions in the RFP design such as prohibiting existing resources from bidding to supply the identified capacity need, allowing only the newest available technology with lower heat rates to participate, allowing only capacity located within a very narrowly-prescribed geographic location to bid, and imposing restrictive criteria that resources must meet in order to qualify to bid – such as high minimum size (MW) requirements or low heat rate guarantees. NOCS recommends the City Council include the following features in its RFP rule:

1. Expressly allow existing and new CHP to bid PPAs as alternates to CT or CCGT capacity needs;
2. Eliminate any requirement for a minimum MW or maximum heat rate in the RFP design (and assess all bids on total production costs);

[68] *See* Supplemental Application, at XXXI. *See also*, Exh. Rice-3: Rice Supplemental Direct, at p. 20, l. 12 – p. 21, l. 13.

3. Include a procedure for stakeholders to challenge the RFP design early in process (to avoid disputes after bid selection as to the structure of the RFP);[69]

4. Require an "Independent Evaluator" instead of an "Independent Monitor" (the latter of which is powerless to direct the utility to change anything about the design of the RFP or selection process);

5. Disallow contract escalators (with the third party contractor retained to construct the utility's self-build option) that hinder regulatory approval due process; and

6. Include provisions that are contained within the MBMO that would encourage industrial customers to build future CHP within the City of New Orleans.

Should the City Council approve ENO's Application, it should condition that approval upon ENO's commitment to follow the Council's RFP rules, once adopted, that allow for the fullest participation by competitors that could provide the needed capacity at a lower total cost of production. RFPs produce the best real-world information as to the true cost to supply the capacity needed by the utility – assuming the RFP is structured in an open, transparent and fair manner so as to generate a robust response from the market – and would inform a decision by the City Council to certify resources selected through such a process.

c. ENO neglected to consider the full range of options to meet any identified need because it didn't fully analyze a transmission solution

In addition to disregarding the results of its own optimization model and refusing to conduct an RFP to vet its self-build NOPS Project, the evidence reveals ENO neglected to consider the full range of options available to meet the identified transmission-related reliability need, because it provided an incomplete analysis of the Transmission Alternative. A transmission solution (through construction of additional transmission lines or enhancement of transmission

[69] The LPSC recently initiated a rulemaking proceeding, entitled "In re: Rulemaking to consider changes to Commission General Order dated October 29, 2008 (Docket No. R-26172 Subdocket C) ('Market Based Mechanisms Order') to incorporate formal complaint procedures" (LPSC Docket No. R-34247), to examine a potential amendment to the MBMO to allow for stakeholders to formally challenge the RFP design early in the process.

facilities) is the first logical option for addressing a transmission-related reliability problem. Yet, ENO chose to evaluate the Transmission Alternative only as an afterthought. Mr. Cureington notes that "the Company has not included detailed design-level transmission estimates because the Company has always planned to mitigate potential NERC violations with a local source of generation located at the Michoud site."[70] Ergo, since ENO never planned to mitigate potential NERC violations with a transmission solution, it claims there is no need to provide a detailed analysis of a transmission solution. ENO's approach categorically ruled out a transmission solution as an option to resolve the transmission-related reliability need.

The Advisors take a different view. Council Advisors' witness, Mr. Vumbaco, notes that Advisors' witness, Phillip Movish, analyzed the Transmission Alternative and found that a transmission solution to the reliability need is feasible, although he harbors concerns about its constructability.[71] Even so, the analyses of its transmission system that ENO presented were flawed. Mr. Movish also finds that ENO's transmission analyses contain conflicting input assumptions which caused the transmission reliability analyses to "reflect a load condition that *inaccurately increases the stress level on ENO's transmission lines* in the event of a transmission contingency…"[72]

ENO could construct additional transmission capacity and access generating capacity through purchases. On this point, Council Advisors' witness, Mr. Rogers, disputes ENO's claims that capacity prices in MISO are set to escalate upon "equilibrium". Mr. Rogers thoroughly

[70] Exh. Cureington-5: Public Cureington Supplemental Direct, at p. 31, ll. 7-10 (*citing* C. Long Supplemental Direct).
[71] *See* Exh. Vumbaco-1: Vumbaco Direct, at p. 23, ll. 1-14.
[72] Exh. Movish-1: Movish Direct, at p. 16, ll. 5-11. (Emphasis added).

analyzed the state of the capacity market in MISO South (in which ENO's service territory is located), and finds that the evidence points to continued low capacity prices.[73]

As the Council's Advisors note, ENO's evaluation of the Transmission Alternative is woefully inadequate – in its current state – to support a decision to pursue that option. The Council could reasonably find that ENO has not fully considered all available options for meeting the identified transmission reliability need due to its flawed and incomplete transmission analysis. ENO should not be rewarded with a $232 million generation project in return for neglecting to fully evaluate a logical solution to the problem presented.

C. Whether ENO's selection of the Michoud site is reasonable

Siting of any new generating capacity is not a focus of NOCS' review of the issues in this proceeding. That said, however, and should this Council approve the RICE Alternative, ENO's Michoud site appears to be reasonable for its location. The Michoud site appears to possess sufficient space and necessary transmission interconnection facilities.

D. Whether ENO's proposed costs, cost recovery mechanism and Monitoring Plan are just and reasonable and should be approved by the Council

ENO requests approval to recover the fixed, non-fuel costs of the CT Alternative or RICE Alternative through its Purchased Power Capacity Acquisition Cost Recovery Rider ("PPCACR") or an alternative exact cost recovery rider.[74] The Council should reject ENO's request for cost recovery through its PPCACR or an alternative exact cost recovery rider. ENO further asks this Council to approve the recovery of fixed, non-fuel costs – assuming that the Council approves a Formula Rate Plan ("FRP") mechanism for ENO – to be ultimately realigned

[73] *See* Exh. Rogers-1: Public Rogers Direct, at p. 36, l. 3 – p. 38, l. 15 (explaining that ENO's forecast of capacity prices in MISO South is likely overstated and that such capacity prices are likely to remain below the "cost of new entry").

to such FRP but outside of the earnings bandwidth.[75] NOCS is vehemently opposed to recovery of the fixed, non-fuel costs associated with the NOPS Project through the PPCACR or an alternative exact cost recovery rider. It is also opposed to recovery of fixed costs outside of the FRP earnings bandwidth. As shown by Council Advisors' witness, Victor M. Prep, P.E., large commercial customers have been inappropriately saddled with a disproportionate share of fixed costs collected on a kWh basis (through the Fuel Adjustment Clause ("FAC")) in an amount exceeding $6,000,000 per year.[76] The first year revenue requirement of the RICE Alternative, as an example, is expected to total $34.4 million.[77] A recovery mechanism employing a kWh-based allocation of such revenue requirements will drastically worsen the already inequitable imposition of fixed costs on commercial customers, as demonstrated by Mr. Prep.

1. The City Council should reject ENO's proposal for cost recovery as it requests approval of prohibited single-issue ratemaking

In the alternative, and only in the event the Council approves either the CT Alternative or the RICE Alternative, it should reject ENO's request for exact cost recovery of such project and should instead order that the costs of such project be considered along with all of ENO's other costs, expenses, revenues and related factors in the context of the forthcoming Combined Rate Case. The fixed costs of either the CT Alternative or the RICE Alternative should be recovered on a going-forward basis through ENO's base rates, set as a result of the Combined Rate Case, rather than through an exact cost recovery rider as sought by ENO. Further, should the Council

[74] *See* Supplemental Application, at XXXVIII. and XXXIX. *See also*, Supplemental Todd Direct, at p. 5, l. 12 – p. 6, l. 7.
[75] *See* Supplemental Application, at XXXIX.
[76] *See* Exh. Prep-1: Public Direct Testimony and Exhibits of Victor M. Prep, P.E. ("Public Prep Direct"), dated November 20, 2017, at p. 27, Table 1 (comparing 2016 fixed costs recovered on a kWh basis through the FAC with recovery of such costs on a Base Rate Revenue Allocation basis).
[77] *See* Exh. Todd-3: Supplemental and Amending Direct Testimony and Exhibits of Orlando Todd ("Supplemental Todd Direct"), dated July 6, 2017, at p. 4, ll. 15-19.

approve either generation project as requested by ENO, it should allocate the fixed, non-fuel costs of such project on a contribution-to-base-revenues basis rather than on a kWh basis, as requested by ENO, because the kWh-basis recovery sought by ENO contradicts cost-causation principles and would constitute inappropriate single-issue ratemaking.

Two primary reasons to allocate the fixed, non-fuel costs associated with the NOPS Project on a contribution-to-base-revenue basis rather than on a kWh basis are: (a) cost-causation principles, and (b) general prohibition against single-issue ratemaking. Cost-causation principles in ratemaking generally dictate that the class of customers causing the utility to incur a cost should be responsible for paying that cost.[80] Single-issue ratemaking occurs when a utility is granted a rate increase or a cost recovery mechanism, such as a rider, designed to recover a single cost or category of costs, as opposed to analyzing all of the utility's costs and revenues in conjunction with each other under traditional ratemaking principles.[81]

NOCS agrees with Mr. Prep's determination that ENO's requested kWh-based allocation method for recovery of the fixed, non-fuel costs associated with the NOPS Project would run contrary to cost-causation principles. He finds that the PPCACR recovers costs on "a volumetric basis which is inappropriate since it gives no weight to peak demands or the timing of cost incurrence."[82] NOCS supports Mr. Prep's recommendation that "the logical approach at this time for preparing an estimate of the ratepayer impact from the allocation of project fixed costs is to

[80] *See, e.g., KN Energy, Inc. v. FERC*, 968 F.2D 1295, 1300 (D.C. Cir. 1992) (holding, "[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."); *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1369 (finding, "the cost allocation mechanism must not be 'arbitrary or capricious' in light of the burdens imposed or benefits received.").

[81] *See Entergy Louisiana, LLC v. Louisiana Public Service Commission*, 2008-0284, p. 17 (La. 7/1/08), 990 So.2d 716, 727 (holding, "Single-issue ratemaking occurs when a utility's rates are altered on the basis of only one of the numerous factors that are considered when determining the revenue requirements of a regulated utility.")(*citing, Business and Professional People for the Public Interest v. Illinois Commerce Comm'n*, 585 N.E.2d 1032 (Ill. 1991)).

allocate them on customer class base revenues," because such "represents a reasonable non-kWh related allocation of fixed cost recovery to use prior to the Combined Rate Case…"[83]

Mr. Prep discusses examples from Louisiana as well as several other jurisdictions of the general prohibition against single-issue ratemaking in his testimony.[84] NOCS agrees with Mr. Prep that ENO's requested cost recovery method would constitute prohibited single-issue ratemaking and should be rejected. As Mr. Prep explains, "The rationale underlying the rule [against single-issue ratemaking] is that a rate based upon the fluctuation of only a single cost factor may overlook savings elsewhere, leading to rates that are not just and reasonable."[85] Further, NOCS supports Mr. Prep's position that exceptions to the general rule against single-issue ratemaking, if allowed at all, should be limited to "unexpected costs that cannot be evaluated in a current or anticipated rate case or expenses that are volatile or fluctuating by nature,"[86] and that no such exception is present in the matter at hand.[87]

The Louisiana Public Service Commission ("LPSC") has repeatedly held that single-issue ratemaking is disfavored and should generally not be used. The following are some instances in which the LPSC has rejected requests for single-issue ratemaking similar to ENO's request in this docket.

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[82] Exh. Prep-1: Public Prep Direct, at p. 6, ll. 14-17.
[83] *Id.*, at p. 8, ll. 11-16.
[84] *See id.*, at p. 12, l. 18 – p. 17, l. 8.
[85] *Id.*, at p. 14, ll. 10-12.
[86] *Id.*, at p. 17, ll. 5-8.
[87] *See id.*, at p. 18, ll. 1-13 (finding that there is no justification for "an exception to the exemption for single issue ratemaking.").

a. LPSC's rejection of single-issue ratemaking concerning hurricane restoration costs

In examining the appropriate recovery mechanism to utilize in designing rates to recover costs incurred as a result of Hurricanes Katrina and Rita, the LPSC reiterated its long-standing resistance to single-issue ratemaking, holding,

> We are not unsympathetic to the approach promoted by the AARP. This is a unique situation. This devastation was unprecedented and these unique circumstances do not precisely lend themselves to traditional ratemaking principles. However, *after more than 20 years of allocating costs, rate increases and rate decreases on a base revenue contribution basis, now is not the time to engage in single issue rate design.*[88]

The LPSC went on to state,

> The Commission Staff and Marathon are entirely correct that we have, for at least the past 20 years, allocated rate increases and decreases for EGS-La and ELL on a base revenue contribution basis. Absent the record that would be required to consider a complete overhaul of all of the all rates for EGS-La and ELL, not just the rates allocating the costs associated with these hurricanes, *the fairest and most equitable approach is to allocate these costs on a base revenue contribution basis.*[89]

Thus, when confronted with requests for recovery of substantial costs incurred as a result of Hurricanes Katrina and Rita, the LPSC maintained the general prohibition against single-issue ratemaking.

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[88] LPSC Order No. U-29203-B (*In re: Joint Application of Entergy Gulf States, Inc. and Entergy Louisiana, Inc. for Interim and Permanent Recovery in Rates of Costs Related to Hurricanes Katrina and Rita. The Companies have requested expedited review of this matter such that the Commission may act on this matter at its January 2006 open session. Phases II and III*), dated August 21, 2007, 2007 WL 2907329, p. 10. (Emphasis added).
[89] *Id.*, p. 11. (Emphasis added).

b. LPSC's rejection of single-issue ratemaking concerning capacity costs arising from Purchased Power Agreements

Similarly, when examining the appropriate recovery mechanism to utilize in designing rates to recover costs incurred as a result of Purchased Power Agreements ("PPAs"), the LPSC again refused to engage in single-issue ratemaking, finding,

> 8. ELI's request to recover the capacity costs for the RS Cogen and ISES 2 contracts through the fuel clause is hereby denied.[90]

In entering the above-referenced order, the LPSC adopted its Administrative Law Judge's Recommendation, which was attached to its order. The Administrative Law Judge's Recommendation provided,

> The Company is not entitled to recover its cost more than once, and *those costs* ***should be examined not as a single issue, but rather in a full ratemaking proceeding*** *so that they are considered in light of all of the Company's revenues that may serve to balance out these expenses.*[91]

The City Council should not depart from these well-established, traditional ratemaking principles which eschew single-issue ratemaking. ENO has not made any case to support such a departure.

2. ENO does not require, nor is it reasonable to afford ENO "exact cost recovery" of any kind

As Council Advisors' witness, Mr. Prep, states, ENO's request for "exact cost recovery" of the fixed, non-fuel costs associated with either the CT Alternative or the RICE Alternative

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[90] LPSC Consolidated Order No. U-25888 and U-27136-B (Corrected) (Docket No. U-25888. LPSC, ex parte. *In re: Investigation of Retail Issues Related to Entergy System Agreement Billings*; Docket No. U-27136. Entergy Louisiana, Inc., ex parte. *In re: Application of Entergy Louisiana, Inc. for authorization to enter into certain contracts for the purchase of capacity and energy*), dated June 5, 2003, 2003 WL 21940665, p. 2.

[91] *Id.*, Consolidated Order No. U-25888 and U-27136-B (Corrected), attached Administrative Law Judge's Recommendation, at pp. 27-28. (Emphasis and bolding added).

should be rejected.[92] ENO has not provided any support for exact cost recovery of such fixed costs. Also as discussed by Advisors' witness, Prep, exact cost recovery represents a form of disfavored single-issue ratemaking.[93] In addition, exact cost recovery of fixed and predictable costs is at odds with traditional regulatory ratemaking principles dictating that rates be established considering all of a utility's costs and revenues and be just and reasonable.[94] Fixed costs, such as those associated with constructing a new generating unit, should be considered along with a utility's other fixed costs, expenses, revenues and related factors, in setting rates for the future. The Louisiana Supreme Court has explained the traditional base ratemaking methodology,

> When fixing the rates to be charged by an electric utility, the Commission determines annually the appropriate "base rate," which is the rate charged per unit of electricity. *Entergy Gulf States, Inc. v. Louisiana Pub. Serv. Comm'n,* No. 98-0881 (La.1/20/99), 726 So.2d 870. The base rate should allow the utility to recoup its revenue requirement, *i.e.* "sufficient revenues to meet its operating expenses, provide its shareholders with a reasonable rate of return, and attract new capital." *Central La. Elec. Co. v. Louisiana Pub. Serv. Comm'n,* 508 So.2d at 1365 (La.1987). Mathematically, the utility's revenue requirement is the sum of the utility's operating expenses and its rate of return times the amount of its rate base. Operating expenses include "maintenance, depreciation, and taxes, incurred to produce revenues;" rate base is "the value of the property, plant and equipment (less accumulated depreciation) which provide the service, and on which a return should be earned;" and rate of return is "a percentage figure which, when applied to the rate base, will generate revenues sufficient to cover costs and give investors a fair return on their investment." *Id.*[95]

When a regulator examines select fixed costs of a utility in conjunction with the totality of the utility's costs and revenues in the context of a base rate case, efficiencies and potential cost savings in other areas can, and often do, ameliorate the exact cost recovery of those selected

[92] *See* Exh. Prep-1: Public Prep Direct, at p. 12, ll. 9-17.
[93] *Id.*
[94] *See Entergy Louisiana, LLC v. Louisiana Public Service Com'n*, 2008-0284, p. 17, 990 So.2d at 727.
[95] *Entergy Gulf States, Inc. v. Louisiana Public Service Com'n*, 1998-1235, p. 2 (La. 4/16/99), 730 So.2d 890, 894-95.

fixed costs. In other words, one set of a utility's fixed costs should not be evaluated in isolation of the utility's other fixed costs, and a regulator's job is not to ensure that rates are set such that each discrete fixed cost is recovered 100%. To the contrary, the regulator's job is to ensure that the utility's fixed costs are prudent and reasonable and that the utility has a fair opportunity (not the guarantee) to recover (a) its fixed costs, (not individually, but as component of its overall revenue requirement), and (b) a reasonable return on its investment.[96] Therefore, the regulator's role is to set rates that will produce a reasonable return on the utility's investment.

Also, as discussed by Advisors' witness, Mr. Prep, ENO is not faced with a lengthy delay until its next base rate case, which delay, some would argue, may otherwise justify a rider to recover newly-incurred and sizeable fixed costs.[97] Here, ENO is set to file its Combined Rate Case in just a few months. The base rates that will result from such Combined Rate Case are expected to go into effect at or around the time of the Commercial Operations Date ("COD") of either the CT Alternative (*i.e.*, 2021) or the RICE Alternative (*i.e.*, 2020). As a result, no regulatory lag regarding recovery of the fixed costs of the NOPS Project is anticipated to occur, and, if it does, such regulatory lag will be of very short duration which can be addressed by pro forma adjustments and other options such as the establishment of a regulatory asset.[98]

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[96] *See Central Louisiana Elec. Co. v. Louisiana Public Service Com'n*, 508 So.2d 1361, 1365-66 (La.1987) (holding that, after determining a utility's (a) revenues, (b) operating expenses, (c) rate base, and (d) rate of return, a regulator must determine the utility's "return" or earnings on its rate base. In doing so, the regulator "must decide whether the utility's actual rate of return is deficient, adequate, or excessive. *South Central Bell,*352 So.2d 864, 967 (La.1977). Commission orders that approve rate increases or require rate decreases *are generally based on the determination that, given the utility's current earnings, the existing rates will likely yield a deficient or an excessive rate of return in the near future.*")(*citing*, Bonbright, *Principles of Public Utility Rates*, p. 150, n. 7 (1961)). (Emphasis added).
[97] *See* Exh. Prep-1: Public Prep Direct, at p. 18, l. 1 – p. 19, l. 4.
[98] *See id.*, at p. 20, l. 1 – p. 21, l. 5.

3. **Fixed, non-fuel costs associated with either version of the NOPS Project should be collected through base rates, as determined in the combined rate case to be filed by ENO this year**

NOCS agrees with Council Advisors' witness, Mr. Prep, that recovery of the fixed, non-fuel costs of any generating project approved by the Council should only occur in the context of ENO's forthcoming Combined Rate Case.[99] ENO has presented no evidence that recovery of the fixed, non-fuel costs associated with the NOPS Project through forward-looking base rates established by the Council in the Combined Rate Case will cause it any undue hardship or that the Council should depart from such well-accepted ratemaking principles governing the recovery of a utility's fixed costs.

4. **The City Council should reject ENO's proposal for cost recovery and order the fixed costs to be recovered on a contribution-to-base-revenues basis**

The Council should reject that part of ENO's cost recovery plan calling for recovery of the fixed, non-fuel costs associated with the NOPS Project on a kWh basis. NOCS agrees with Mr. Prep that a kWh (or volumetric) basis is an inappropriate method by which to collect known and measurable costs. Known and measurable costs should be recovered following cost-causation principles, such as through a contribution-to-base-revenues basis. As Council Advisors' witness, Mr. Prep, states regarding fixed costs, "demand cost allocation methodology is much more appropriate than a kWh-based allocation."[100] He goes on to advocate "that base rate revenue be used to develop a current estimate of the project fixed costs allocated to customer classes, with the final allocation methodology to be determined in the Combined Rate Case."[101]

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[99] *See id.*, at p. 19, ll. 5-15.
[100] *Id.*, at p. 3, ll. 4-6.
[101] *Id.*, at p. 3, ll. 6-10.

To illustrate the adverse effect on cost-causation principles, Mr. Prep includes a table in his testimony that reveals fixed costs recovered through ENO's FAC (*i.e.*, a kWh-based mechanism similar to the PPCACR) have over-allocated over $6,000,000 annually to the Large Commercial class of ENO's customers.[102] The Council should correct the misallocation of fixed costs on a kWh basis and should avoid repeating it here.

Air Products' witness, Mr. Brubaker, similarly finds that a kWh-based recovery mechanism for the fixed, non-fuel costs associated with the NOPS Project is inappropriate.[103] He states, "Regardless of whether the Rider is called PPCACR or something else, recovery of non-fuel revenue requirements associated with generation facility investment or generation PPAs by means of a kWh mechanism is not cost-based and is outside the mainstream of cost recovery practices."[104] NOCS could not agree more. Mr. Brubaker continues, advocating that, "In the absence of a class cost of service study, the appropriate approach would be to apply a uniform percentage factor to the base rate revenues of all customer classes. This would essentially preserve existing rate relationships, and would be consistent with generally accepted cost of service principles."[105] NOCS supports Mr. Brubaker's approach, which follows closely with that of Mr. Prep.

5. If there is an FRP established in the Combined Rate Case, the fixed, non-fuel costs associated with either version of the NOPS Project should be collected inside (and subject to) the earnings bandwidth

Council Advisors' witness, Mr. Prep, also discusses the potential for the establishment of an FRP mechanism in the forthcoming Combined Rate Case.[106] NOCS supports Mr. Prep's

[102] *See id.*, at p. 27, Table 1.
[103] *See* Exh. Brubaker-2: Public Brubaker Additional Direct, at p. 11, ll. 7 -10.
[104] *Id.*, at p. 11, ll. 19-22.
[105] *Id.*, at p. 12, ll. 8-11.
[106] *See* Exh. Prep-1: Public Prep Direct, at p. 23, l. 6 – p. 24, l. 5.

conclusion that any realignment of the fixed, non-fuel costs associated with the NOPS Project to the FRP should be realigned inside the earnings bandwidth.[107] ENO's proposal to realign such fixed costs outside of the earnings bandwidth, translated, means that it requests 100% guaranteed recovery of such fixed costs.

Part of an FRP is the earnings bandwidth. Typically a regulator will examine a utility's return on equity from the prior test year to determine whether the return on equity fell within the bandwidth. The bandwidth is a zone around the authorized rate of return for a utility, usually comprised of ± a certain number of basis points. For example, ENO's affiliate, ELL, operates under a FRP with a bandwidth of ± 80 basis points[108] around its authorized rate of return of 9.95%,[109] meaning the bandwidth spans from a low of 9.15% to a high of 10.75%. If ELL's return on equity during the test year falls within the bandwidth of 9.15% to 10.75%, regardless of whether it incurred certain fixed costs not otherwise included in its base rates during the test year, there is no change in rates. If ELL under-earns (*i.e.,* its return on equity falls below 9.15%) it is entitled to a rate increase but not in the full amount necessary to get its return back to the bottom of the bandwidth; it must absorb part of the under-earnings. Conversely, if ELL over-earns (*i.e.,* its return on equity exceeds 10.75%), it must reduce rates but not in the full amount necessary to get its return back to the top of the bandwidth; it gets to retain part of the over-earnings. The concept of an FRP, therefore, is to allow a utility operational flexibility which would enable it to find efficiencies in light of all factors – including incurrence of new capital costs – such that its return stays within or exceeds the bandwidth.

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[107] *See id.* The earnings bandwidth is also referred to as the "Return on Equity Bandwidth" or "ROE Bandwidth".
[108] *See* ELL Rate Schedule FRP, Sec. 2.C.1.(e): http://www.entergy-louisiana.com/content/price/tariffs/ell_frp.pdf.
[109] *Id.*, at page 157.25, line 2 (Evaluation Period Cost Rate for Common Equity).

When capital costs are recovered outside of the bandwidth in an FRP, that means they are recovered via a rider or an exact cost recovery mechanism (without any sharing), regardless where the utility's return on equity falls during the test year. Collection of capital costs outside of the bandwidth in an FRP, therefore, removes the incentives for the utility to operate efficiently (lest it be required to absorb part of its under-earnings) and denies the benefit of the bargain to ratepayers.

If ENO's base rates are established in the Combined Rate Case in a just and reasonable fashion (and there is no reason to believe they will not be), it will be afforded the opportunity to recover all of its fixed, non-fuel costs associated with the NOPS Project. An ensuing FRP should be designed utilizing those newly-established base rates (designed, in part, to recover the cost of NOPS), and an earnings bandwidth will be set using the freshly-authorized return on equity. Nothing in this scenario would justify departing from the ratemaking principles underlying an FRP, as ENO requests. Collection of the fixed, non-fuel costs associated with the NOPS Project outside of the earnings bandwidth would grant ENO a double benefit by allowing it to reap the rewards of any over-earning while, at the same time, guaranteeing it 100% recovery of the NOPS capital costs. The Council should soundly reject ENO's request.

6. The LTSA costs are fixed and predictable in nature and should be allocated and collected in the same manner as the other fixed, non-fuel costs of the project

Finally, NOCS agrees with Council Advisors' witness, Mr. Prep, that the costs associated with the LTSA are predicable costs and should, therefore, be recovered together with other fixed costs of the project through forward-looking base rates rather than through the FAC.[110]

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[110] *See* Exh. Prep-1: Public Prep Direct, at p. 24, l. 7 – p. 25, l. 5.

CONCLUSION

For all of the above and foregoing reasons, NOCS respectfully requests the City Council to deny ENO's Application and initiate a rulemaking proceeding to adopt RFP rules and regulations, with consideration of the features specifically mentioned above. Specifically, NOCS requests the following:

The City Council should Deny ENO's Application for the 226 MW CT Alternative

The City Council should deny ENO's NOPS Application because it has not shown that a 226 MW CT is necessary or the best or most economical option to meet the identified, minimal need for capacity, based upon the evidence in the record, including:

- Load growth projections have been declining since the 2015 IRP.
- The CT Alternative is far too large and expensive to meet the 99 MW need in 2026.
- The CT Alternative was not selected utilizing any optimization model; in fact, ENO's AURORA optimization model employed in conjunction with the 2015 IRP (where the CT Alternative was selected) selected CCGT resources in three of the four scenarios, and a combination of solar and wind resources in the fourth scenario, as the best and most economical resources to meet the need.
- The CT Alternative was not selected as a result of an RFP. ENO should have conducted an RFP to test the market to obtain the lowest reasonable cost solution, especially considering CT Alternative and RICE Alternative are self-build projects.
- The CT Alternative is not as flexible as RICE Alternative and would not possess black-start capability.

- The CT Alternative will rely far more heavily on ground water than the RICE Alternative.

Should the City Council find that Generating Capacity is needed, it should Certify ENO's Application for the 128 MW RICE Alternative, with Conditions

Should the City Council grant ENO's NOPS Application to the extent that it seeks approval of the 128 MW RICE Alternative, it should impose reasonable conditions, including the following:

- The City Council should initiate a rulemaking proceeding designed to develop RFP rules and procedures and, as a condition of approval of the RICE Alternative, require ENO to issue a formal RFP for any long-term resource need it identifies in the future.
- The City Council should find that, given ENO's choice to forego generating resource alternatives that were less expensive than the RICE Alternative,[111] coupled with its actions in selecting the RICE Alternative, including, but not limited to, ENO's refusal to rely on its AURORA optimization model results and its decision to bypass testing this self-build project against the market through an RFP, any approval of the RICE Alternative should be conditioned upon the imposition of a cap on the fixed, non-fuel costs associated with the construction of such project that may be recovered from ENO's customers as the not-to-exceed construction costs represented by the caps in the EPC contracts. Placing such a cap on the cost of the NOPS Project that may be recovered from ENO's ratepayers would protect them from cost overruns and/or escalations in construction costs due to factors beyond their control.

[111] ENO backed out of its agreement to purchase approximately 20% of its affiliate's St. Charles Power Station CCGT project, which costs only $886/kW, as compared to the price tag for the RICE Alternative of $1,640/kW.

<u>Should the City Council Approve either Generation Alternative in ENO's Application, it should Reject ENO's Requests concerning Cost Recovery</u>

Should the City Council approve either generating alternative (again, NOCS submits that, if a resource is selected, it should be the RICE Alternative and not the CT Alternative), it should reject ENO's requested cost-recovery methodology:

- ENO's proposal for recovery of the fixed, non-fuel costs associated with the NOPS Project through the PPCACR or some other "exact cost recovery" rider is contrary to cost-causation principles and represents a request for inappropriate single-issue ratemaking.
- ENO does not require, nor is it reasonable to afford ENO, "exact cost recovery" of any kind under the circumstances and based on the evidence in the record.
- Fixed, non-fuel costs associated with either version of NOPS Project should be collected through forward-looking base rates, as determined in the Combined Rate Case to be filed by ENO this year.
- Fixed, non-fuel costs associated with either version of NOPS Project should be allocated to customer classes on a contribution-to-base-revenues basis, and not on a kWh basis.
- The LTSA costs are fixed and predictable in nature and should be allocated and collected in the same manner as the other fixed, non-fuel costs of the project, discussed herein.
- If there is an FRP established, the fixed, non-fuel costs associated with either version of NOPS Project should be collected inside (and subject to) the earnings bandwith.

NOCS also prays for all other and equitable relief available to it under the facts and the law.

Respectfully submitted:

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CERTIFICATE

I hereby certify that on this day a copy of the foregoing New Orleans Cold Storage & Warehouse Co. Ltd.'s Post-Hearing Brief has been sent to the official service list by email, and/or served by United States mail, postage prepaid, through their representatives, at the following addresses:

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New Orleans, Louisiana, this 19th day of January, 2018.

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