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January 19, 2018

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

Re: Supplemental and Amending Application of Entergy New Orleans, LLC for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief
CNO Docket NO.: UD-16-02

Dear Ms. Johnson:

Please find enclosed for your further handling an original and three copies of Entergy New Orleans, LLC's ("ENO") Public Version Post Hearing Brief. Please file an original and two copies into the record in the above referenced matter, and return a date stamped copy to our courier.

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

Thank you for your assistance with this matter.

Sincerely,

Brian L. Guillot

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BY: C. S. Hanes

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Enclosures

cc: UD-16-02 Official Service List (*via electronic mail and UPS overnight*)

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	)))))))	**DOCKET NO. UD-16-02**

<u>POST-HEARING BRIEF OF ENTERGY NEW ORLEANS, LLC</u>

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PUBLIC VERSION

January 19, 2018

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POST-HEARING BRIEF OF ENTERGY NEW ORLEANS, LLC

Entergy New Orleans, LLC[1] ("ENO" or the "Company"), through its undersigned counsel, respectfully submits this Post-Hearing Brief in support of its request that the Council of the City of New Orleans ("Council") grant ENO authorization to proceed with constructing the New Orleans Power Station ("NOPS" or the "Project"), which will consist of either a combustion turbine ("CT") resource with a summer capacity of 226 megawatts ("MW"), or alternatively, seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator sets ("Alternative Peaker").[2]

Introduction

Throughout a year and a half of litigation, and the extensive record created in this docket, two competing views of the City of New Orleans have emerged. Under one view, New Orleans is a viable, growing City that takes responsible and proactive steps to continue on the path to a bright future, which includes providing reliable electric service for its citizens. Under the other view, which is based on an "anything-but-a-gas-plant" ideology, New Orleans is a city that is

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

2 The use of "NOPS" throughout this Post-Hearing Brief refers generally to either the original CT or the Alternative Peaker.

paralyzed by Hurricane Katrina's flooding and that does not invest in key infrastructure, simply waiting on other utilities to take action or for certain technologies to mature in order to provide basic services to its citizens, like reliable and affordable electric service.

In proposing NOPS to the Council, ENO has firmly committed itself to the optimistic, self-determined view. ENO needs local electric generation to reliably serve its customers, and it has a particular need for a modern, efficient gas-fired resource like NOPS that can ramp-up quickly to provide power during the hottest and coldest times of the year. Since Michoud Units 2 and 3 deactivated in 2016, ENO, for the first time in modern history, has not had an operational electric generating facility within the City. It is unquestionable that a great city like New Orleans, given its unique circumstances, needs such a facility. Without it, the City and its citizens are at risk of cascading electric outages (also called "blackouts") and face greater difficulty in recovering from hurricanes. With it, a baseline level of reliability will be established, clearing the way to pursue increases in renewable resources, energy efficiency, and some of the other resources advanced by the Joint Intervenors in this case without the need to be concerned about high-impact, widespread outages or the lack of a generating unit for hurricane responses. By taking action to construct NOPS, the Council will not only address these reliability concerns, but it will also support economic growth in the City, and facilitate further use and expansion of renewable energy. It also is undisputed that constructing and operating NOPS will bring new jobs and hundreds of millions of dollars of economic benefits to the City.

In the light of these benefits and ENO's capacity and reliability needs, it is not surprising that the Advisors to the Council of the City of New Orleans (the "Advisors") share ENO's view that constructing local generation is necessary and important to the City's future. The Advisors recommend that the Council approve construction of the Alternative Peaker, explaining that "the

RICE Alternative presents the most viable alternative for the Council's consideration in the instant docket to resolve ENO's current transmission system reliability issues and, accordingly, is the Advisors' collective recommendation to the Council for approval."[3] ENO's largest industrial customer, Air Products and Chemicals, Inc. ("Air Products"), which is heavily invested in New Orleans East, also has confirmed its support for new generation in the City and its preference for the Alternative Peaker.

Opposing ENO's Supplemental and Amending Application for approval to construct NOPS are the Alliance for Affordable Energy, the Sierra Club, the Deep South Center for Environmental Justice, and 350 Louisiana – New Orleans (collectively, the "Joint Intervenors").[4] By dismissing ENO's capacity and reliability needs and the flood and storm-surge protections put in place after Hurricane Katrina, the Joint Intervenors contend that the Council should not approve construction of a new generating unit in New Orleans East and should instead rely on the wholesale market and potential changes in technology to meet the long-term needs of ENO's customers. Following this recommendation would be a risky gamble that is inconsistent with the need to prudently plan for the City's current and future energy needs. Not one of the Joint Intervenors' seven witnesses has any experience with planning or operating an electric utility in New Orleans or Louisiana; and none of them provide an independent forecast of ENO's long-term capacity needs or a proposed portfolio of resources to meet those needs or to avoid

[3] Advisors Exhibit Vumbaco-1 (Vumbaco Direct) at 8-9.

[4] It should also be noted that New Orleans Cold Storage & Warehouse Co. Ltd. ("NOCS") made an appearance through counsel at the December 2017 Hearing, but it did not offer an opening statement, choosing instead to generally "echo" the comments of Air Products and Advisor witness Mr. Prep on cost recovery. Tr. (Opening Statements) 12/15/17, at 109-10. NOCS did not file any testimony in this docket to alert parties to its positions or cross-examine any witnesses at the hearing.

cascading outages. They have no plan at all, and, as the Advisors appropriately warn, this "do nothing" approach presents an unacceptable risk to the City and its citizens.[5]

Considering these two competing views, the Council's path is straightforward. Indeed, recent challenges faced by the Sewerage & Water Board demonstrate the importance of timely investment in necessary infrastructure. Safe and reliable electric service is essential to the City's future, and the Council should ensure that the City receives the benefits that only a reliable, flexible resource like NOPS can bring. The evidence submitted on each of the contested issues in this docket confirms in overwhelming fashion that the construction of NOPS is in the public interest and should be approved:

- ***ENO has a long-term need for peaking capacity, which NOPS will provide.*** The long-term need was created largely as result of the early deactivations of Michoud Units 2 and 3, and numerous analyses conducted over the last several years have identified and confirmed that a dispatchable, peaking resource, like NOPS, located at the Michoud Site, is the most cost-effective way of meeting that specific need, considering ENO's unique circumstances. And because of ENO's unique circumstances and the specific need for peaking capacity, renewable resources are insufficient – they are intermittent and cannot be relied upon when needed most (*e.g.,* on hot summer evenings, during transmission or generation outages, or in the aftermath of a severe storm), which is the very purpose of a peaking resource. Transmission upgrades and battery storage are also insufficient because they do not create power, they just move it around or store it – ENO needs a resource in New Orleans that can be counted on to produce power where, when, and for as long as needed, which is NOPS.

- ***ENO has had a current and persisting reliability need since the deactivations of Michoud Units 2 and 3.*** This need, including the risk of cascading outages and current operational transmission grid issues (*i.e*., denied outages and frequent load-at-risk alerts), must be addressed; and it is undisputed that constructing NOPS at the Michoud Site will provide a reliable solution. Constructing NOPS will also increase storm preparedness, operational flexibility, reliability margins, reactive power, economic growth, and reduce transmission line loading. Simply put, other resources – *i.e.*, transmission upgrades that cannot be constructed because of significant outage requirements, increased levels of load reduction over time that may never materialize, batteries that will only last for a short period

[5] *Id.* at 23.

of time during a hurricane, or some combination of these resources, *etc*. — will not address the suite of reliability concerns that local generation would mitigate.

- ***In its long-term planning process, ENO considered a full range of options to meet its capacity and reliability needs, and the proposed NOPS units are the appropriate choices to meet those needs.*** ENO's 2015 Integrated Resource Plan identified the Company's supply needs, considered a wide range of future scenarios and resource alternatives to meet those needs, and determined that a new CT is the lowest reasonable cost resource capable of meeting those needs. The CT option for NOPS is flexible, can run as long as needed, supports both storm response and the addition of renewable resources, and provides customers with a valuable hedge against market capacity and energy prices. The Alternative Peaker and its RICE technology are a viable alternative to the CT option, offering these same benefits plus black-start capability, which would allow the plant to start up under its own power after a hurricane or major outage without a backfeed of power from the electric grid.

- ***The Michoud Site is the ideal location to construct NOPS.*** Because of its historical use as a power facility and its location on ENO's system, the Michoud Site is the most appropriate place to construct local generation in Orleans Parish and address ENO's reliability needs. The site is close to major gas pipelines, has existing office infrastructure, and is strongly interconnected to the transmission system. The Michoud Site is well protected by the Hurricane and Storm Damage Risk Reduction System ("HSDDRRS"), and ENO has mitigated flood risk in the planning for NOPS. No people live within a one-mile radius of the center of the site, and the Company will comply with all local, state, and federal laws and regulations that apply to the Project. Construction of NOPS at the Michoud Site will not adversely affect the environment or the community in New Orleans East. But it will provide jobs, increase tax revenue to the City, and spur economic growth.

- ***The proposed costs of the NOPS units are reasonable and necessary to address ENO's capacity and reliability needs, and ENO's proposed cost recovery mechanism and Monitoring Plan are likewise reasonable and necessary to secure the benefits of local generation for ENO's customers.*** ENO has assembled a Project Team for NOPS that has extensive, successful experience with generation projects. For the CT and RICE options, the Company has engaged industry-leading contractors and tested their pricing through a competitive selection process. The record includes extensive information about cost protections and risk mitigation measures that ENO is employing in connection with the Project, and no witness has challenged the Company's approach. For ENO to undertake the investment necessary to construct NOPS, it must have reasonable assurances from the Council that such investment would be recovered on a timely/"in service" basis. The testimony of the Company and certain testimony of the Advisors in this docket provides the bases and methods for such assurances and proposals for potential mechanism(s) that would result in just and reasonable rates.

The Public Interest Standard

"The public interest is that which is thought to best serve everyone; it is the common good."[6] In the context of utility regulation, the Supreme Court of Louisiana has found that the public interest standard is "designed to assure the furnishing of adequate service to all public utility patrons at the lowest reasonable rates consistent with the interest both of the public and of the utilities."[7] This standard affords regulatory bodies in Louisiana the flexibility to consider a broad range of issues relevant to the interests of the public and the utility, while keeping the goal of reliable utility service at the lowest reasonable cost paramount. Accordingly, while the Council, in its Final IRP Resolution, indicated that certain issues may be advanced and vetted in its review of ENO's application,[8] the Council did not, in doing so, upset its obligation to follow established jurisprudence related to the public interest standard in Louisiana. ENO's obligation to provide, and the Council's obligation to ensure, reliable, low-cost service to ENO's customers are factors that must be considered as well as other relevant factors deemed appropriate for consideration by the Council when making its decisions, consistent with Louisiana law.

This balancing-of-interests approach is consistent with over 60 years of regulatory decision-making and judicial review. Indeed, beginning with *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 660 (1944), the courts have found that if the regulatory body's decision reflected a reasonable balancing of customer and investor interests,

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[6] ENO Exhibit Lovorn-1 (Lovorn-Marriage Direct) at 9.

[7] *City of Plaquemine v. Louisiana Pub. Serv. Comm'n*, 282 So.2d 440, 443 (La.1973).

[8] *See e.g.*, Council Resolution No. R-17-100 at Ordering Paragraph 2, identifying issues "including, but not limited to the need for a CT, size, timing, environmental concerns, social justice, cost, transmission, and reliability considerations." At the December Hearing, counsel for the Alliance for Affordable Energy seemed to suggest that the Council's enumeration of these non-exclusive factors in the Resolution issued in Docket UD-08-02 was intended to supplant the public interest standard subscribed to by the Louisiana Supreme Court. *See* Tr. (Lovorn-Marriage) 12/20/17, at 33-34. Any argument advanced by Joint Intervenors positing that the Council intended to deviate from decades of jurisprudence and regulatory practice and adopt a different or novel public interest standard by enumerating a *non-exclusive* list of factors would wholly lack merit, for it would arbitrarily and improperly limit the Council's consideration of the public interest.

the decision was to be affirmed as just and reasonable. When considering the obligations to provide and ensure low-cost reliable service for ENO's customers, along with other factors, the evidence in the record demonstrates that "the selection of either NOPS Alternative would serve the public interest."[9]

Arguments

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

A. Whether ENO has a demonstrated capacity need

1. The evidence confirms that ENO has an overall need for long-term capacity, a substantial need for long-term peaking and reserve capacity, as well as unique planning needs in New Orleans that justify construction of NOPS.

The record is clear in this proceeding that ENO needs long-term capacity. Such capacity needs to be dispatchable, peaking capacity; and it needs to be located in New Orleans East at ENO's Michoud Site. As explained by ENO witness Mr. Seth E. Cureington, who is ENO's Director of Resource Planning and Market Operations,[10] the need for long-term capacity is driven primarily by the early deactivations of Michoud Units 2 and 3 in June 2016, which units were located in an industrial area of New Orleans East (the "Michoud Site") and provided approximately 781 MW of local generating capacity within Orleans Parish in support of reliable operations, and that also mitigated supply- and market-related risks.[11] The Company has long stated that Michoud Units 2 and 3 were deactivated for economic reasons related to maintenance and other operational issues that, among other things, threatened worker safety;[12] and, although the Company answered numerous discovery requests in this docket related to the circumstances

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9 ENO Exhibit Lovorn-2 (Lovorn-Marriage Rebuttal) at 25.

10 ENO Exhibit Cureington-2 (Cureington Direct) at 1.

11 *Id.* at 3, 15; ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 17-25.

12 ENO Exhibit Cureington-2 (Cureington Direct) at 3, 15.

surrounding the deactivations of Michoud Units 2 and 3, no party in this proceeding has filed expert testimony or offered any evidence that questioned the reasonableness of the deactivations.

The resulting loss of approximately 781 MW of local capacity (representing approximately [redacted] of the Company's 2016 forecasted non-coincident peak load) resulted in an accelerated and significant overall long-term need for capacity, specifically local peaking and reserve capacity.[13] The acquisition of Power Block 1 of the Union Power Station in southern Arkansas ("Power Block 1") helped to offset some of that need (including base load and load-following needs), but both an overall as well as a peaking and reserve long-term capacity need still remain. As explained by Mr. Cureington, using the most recent forecast of peak load, ENO projects an overall need of approximately 99 MW of capacity by 2026, which grows to approximately 248 MW by 2036, the end of the 20-year planning horizon.[14] Moreover, the current forecast indicates a persistent peaking and reserve deficit of approximately 342 MW on average in each year of the 20-year planning horizon.[15]

Recognizing the significant capacity need, the Company conducted numerous analyses, including economic analyses, over the last several years to identify the best way to meet the identified need, and each analysis confirmed that a dispatchable, peaking resource located in New Orleans East is the best alternative for meeting the identified long-term capacity need, considering risk and ENO's unique planning circumstances. As explained by Mr. Cureington, those unique planning circumstances include the following undisputed facts:

- ENO's load is located entirely within the transmission-constrained Downstream of Gypsy ("DSG") load pocket (which is located entirely within the Amite South

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13 *Id.* at 4.

14 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 7; Exhibit SEC-11.

15 *Id.*

load pocket), and with the deactivation of Michoud Units 2 and 3, ENO is now 100% dependent on transmission to import power to serve its load.[16]

- The Company's service area is at the eastern geographic boundary of DSG and surrounded by water on three sides. This means that ENO relies heavily on high-voltage transmission lines to import power from West to East.[17]
- Entergy Louisiana, LLC owns the Ninemile Point facility, which is the only remaining significant source of local reliability in DSG, and two of the three remaining units at Ninemile (71% of the Ninemile generating capacity) are approaching 50 years in age and will not operate forever.[18]
- The majority of ENO's generating capacity is located outside of both DSG and the broader Amite South load pockets, which load pockets also rely, in part, on aging generation resources that are over 40 years old and which could deactivate early.[19]
- [redacted] of the Company's generating capacity is located outside the New Orleans Load Zone, which increases customer exposure to Locational Marginal Prices ("LMPs") during planned outages of transmission and generation.[20]
- [redacted] of the Company's generation is located outside Local Resource Zone ("LRZ") 9, which creates risk of price separation in the Midcontinent Independent

[16] ENO Exhibit Cureington-8 (Cureington Rebuttal) at 8.

[17] *Id.* at 9-10.

[18] *Id.* at 10.

[19] *Id.* at 11-12.

[20] *Id.* at 12.

System Operator, Inc. ("MISO") Planning Resource Auction ("PRA") clearing prices.[21]

- As explained by Mr. Cureington and Mr. Charles W. Long, ENO's electric grid has always been planned to include a dispatchable resource located in New Orleans East.[22]

Over the years, it is also significant that the Company has performed numerous economic analyses related to the proposed NOPS unit. A brief description of these analyses follows:

The first analysis confirming that a dispatchable, peaking resource is the best alternative for meeting ENO's long-term capacity need was the 2015 Integrated Resource Plan ("IRP"). As explained by Mr. Cureington, the IRP documented the extensive analysis undertaken, and the stakeholder input sought, over the course of nearly 18 months of work that resulted in the conclusion that the Company has a substantial need for peaking and reserve capacity, and that a CT is the lowest reasonable cost alternative for meeting that need.[23] The analyses undertaken as part of the IRP involved hundreds of hours of data review, modeling, post-processing analysis, and stakeholder review, as well as public technical conferences and reports to the Council.[24]

In addition to the 2015 IRP, the Company conducted a technology assessment in 2015 that compared a number of different combustion turbine technologies and one internal combustion engine configuration against a range of factors, including fixed and total supply cost, operational flexibility, ENO's planning needs, and gas pressure requirements.[25] That assessment

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[21] ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 22-23; ENO Exhibit Cureington-8 (Cureington Rebuttal) at 12.

[22] Tr. (Cureington) 12/18/17, at 250, 336; ENO Exhibit C. Long-3 (C. Long Rebuttal), at 10.

[23] ENO Exhibit Cureington-8 (Cureington Rebuttal) at 59; ENO Exhibit Cureington-2 (Cureington Direct) at Exhibit SEC-7 (the Final 2015 IRP).

[24] ENO Exhibit Cureington-8 (Cureington Rebuttal) at 59.

[25] ENO Exhibit Cureington-2 (Cureington Direct) at 35; Exhibit SEC-5.

confirmed that the 226 MW CT best fit ENO's planning needs.[26] The Company then conducted another technology assessment in March 2016 that compared the proposed 226 MW CT to two smaller alternative CTs.[27] That analysis confirmed that the 226 MW CT was the more economic choice as compared to installing one smaller CT early in the planning horizon and then another smaller CT several years later.[28]

The Company also submitted Supplemental Testimony in November 2016 in compliance with Council Resolution R-16-506 (November 3, 2016), which required the Company to perform production cost modeling requested by the Advisors on September 19, 2016.[29] That Supplemental Testimony included total supply cost analyses for four alternative portfolios, which included one portfolio that contained the proposed 226 MW CT, a second portfolio that included only transmission investment, a third portfolio that included the effect of achieving the Council's 2% demand-side management ("DSM") goal,[30] and a fourth portfolio that included the effect of advanced metering-enabled load controls and battery storage technologies.[31] The results of those analyses confirmed that the 226 MW CT was the most cost-effective alternative for meeting ENO's identified long-term capacity needs.[32]

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[26] ENO Exhibit Cureington-2 (Cureington Direct) at 35; Exhibit SEC-5.

[27] ENO Exhibit Cureington-2 (Cureington Direct) at 36; Exhibit SEC-6.

[28] ENO Exhibit Cureington-2 (Cureington Direct) at 36-41; Exhibit SEC-6.

[29] At hearing, counsel for the Joint Intervenors presented Mr. Cureington with a discovery response produced by the Advisors in this docket, which purportedly contained a different version of the requested modeling. Mr. Cureington stated, however, that he could not recall ever having seen that document, and that the only request he was familiar with and performed was included with his testimony as Exhibit SEC-8. Tr. (Cureington) 12/18/17, at 172, 175.

[30] *See* Resolution No. R-15-599.

[31] ENO Exhibit Cureington-4 (Cureington Supple

mental Direct) at 7; Exhibit SEC-8.

[32] ENO Exhibit Cureington-4 (Cureington Supplemental Direct) at 8; Exhibit SEC-9.

Finally, in July 2017, the Company submitted Supplemental and Amending Direct Testimony, based on the most up-to-date peak capacity forecast, and which included additional economic analyses, including analyses that were requested by the Advisors on March 23, 2017. As explained by Mr. Cureington, the analyses in the Supplemental and Amending Direct Testimony included a smaller NOPS alternative, the 128 MW RICE units.[33] In those analyses, the Company modeled three "Reference Cases," in which one included the 226 MW CT, another modeled the 128 MW RICE units, and a third modeled only transmission investment.[34] The Company also included sensitivities for high, reference, and low gas prices as well as a lower MISO PRA capacity price sensitivity.[35] In addition, the Company modeled four "Requested Portfolios" that included the (1) 226 MW CT, (2) the 128 MW RICE units, (3) 100 MW of additional solar resources, and (4) 300 MW of wind resources.[36] Those Requested Portfolios also assumed the effect of achieving the Council's 2% DSM goal as well as including sensitivities for different gas prices and a lower MISO PRA capacity price sensitivity.[37]

As explained more fully below, while the Company disagrees with the assumptions around the achievability of the Council's 2% goal and the reduced MISO capacity price forecast, the overall results of the latest analyses indicated that the 226 MW CT, the 128 MW RICE units, and the 100 MW solar portfolios are roughly equal in terms of total supply costs.[38] However, as Mr. Cureington explained, traditional gas-fired generating units like the CT and RICE units are needed to meet current and projected long-term peaking and reserve capacity needs due to their

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33 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 1-2.

34 *Id.* at 4, 26-27.

35 *Id.* at 26-27.

36 *Id.* at 31-33.

37 *Id.*

38 *Id.* at 28-29, 34-35; Exhibit SEC-13.

lower installed cost and operational flexibility when compared to other dispatchable resource alternatives,[39] while renewable resources, as explained below, are simply not effective and reliable peaking technologies. In other words, the RICE and CT technologies can be counted on to provide a flexible, reliable, and sustainable source of power right when it is needed the most — on hot evenings when usage peaks, during planned and unplanned transmission and generation outages, and in the aftermath of severe storms.

2. *Renewable resources and transmission investments are not viable alternatives to a dispatchable, local peaking resource.*

Importantly, because the identified need is for a peaking and reserve resource, renewable resources cannot meet that need precisely because they are not dispatchable. As explained by Mr. Cureington, although there are benefits associated with renewable resource alternatives, such as hedging against exposure to volatility in the price of natural gas, the intermittent nature of renewable resources limits the Company's ability to rely on them to meet peak demand.[40] Thus, should the Company need to call on such resources to ramp-up production when customer demand peaks or an unplanned event occurs, which is the very purpose of a peaking unit, those resources would not provide that capability.

Indeed, because renewable resources like solar and wind are intermittent, they must be backed up with dispatchable resources to ensure sufficient resources are available to ramp-up and produce replacement energy when it is cloudy, late in the day, or the wind is not blowing.[41] Even Joint Intervenors witness Dr. Elizabeth A. Stanton conceded that solar and wind are not peaking resources.[42] Furthermore, the Company's summer peaks occur late in the day when

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39 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 45.

40 *Id.* at 22-23; ENO Exhibit Cureington-8 (Cureington Rebuttal) at 14.

41 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 45.

42 Joint Intervenors Exhibit Stanton-2 (Stanton Direct) at 27; Tr. (Stanton) 12/21/17 at, 26.

customers are returning home from work and turning on lights and appliances and lowering thermostat settings.[43] Given that profile, solar is not a viable peaking resource because it is often unavailable or declining (*i.e.*, the sun is setting) right when it is needed most. Moreover, as Mr. Cureington describes, having a local, dispatchable resource actually supports the addition of future renewable resources.[44]

Moreover, because renewable resources receive a lower capacity credit in MISO, the Company cannot count a megawatt of renewable resource capacity equal to a megawatt of gas-fired generation in planning to meet its long-term capacity needs.[45] So even if those intermittent resources could meet the Company's long-term need for peaking and reserve capacity (which they cannot), the Company would need to acquire significantly **more** capacity than its need dictates due to the lower capacity credit. This means that while renewable resources have significant benefits (ENO is currently taking measures to add up to 100 MW of solar to its portfolio), many utilities have found that intermittent resources need to be backed up by traditional resources like NOPS.[46] In fact, Joint Intervenors witness Peter J. Lanzalotta conceded at hearing that one of the benefits of quick start generation, like NOPS, is its ability to support the variable output of intermittent generation.[47]

In contrast to the Company's reasoned analysis that considered ENO's specific needs and unique planning circumstances, two of the Joint Intervenors' witnesses, Dr. Stanton and Mr. Robert M. Fagan, who are both out-of-state consultants located in Massachusetts with no

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[43] ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 45-46.

[44] ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 46.

[45] ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 22-23; ENO Exhibit Cureington-8 (Cureington Rebuttal) at 15.

[46] ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 22-23; ENO Exhibit Cureington-8 (Cureington Rebuttal) at 15.

[47] Tr. (Lanzalotta) 12/21/17, at 64-65.

practical experience in resource planning or operations in New Orleans or MISO South,[48] suggest solar as an alternative resource technology generally. They both admitted, however, that they did not conduct any analysis regarding the cost or feasibility of incremental solar in New Orleans.[49] With respect to other renewable resources, such as wind-created power, Dr. Stanton further admitted at hearing that she had not conducted any analysis with respect to whether wind purchased power agreements are available, their associated costs, or whether transmission would be available to import remote wind resources.[50] Said differently, Dr. Stanton and Mr. Fagan both ignored ENO's specific needs and unique planning circumstances.

Similarly, yet another technology touted by the Joint Intervenors is battery storage. Simply put, however, battery storage is not a viable alternative technology for meeting ENO's specific needs. While battery storage technology is also suggested as a viable alternative generally by the Joint Intervenors, both Dr. Stanton and Mr. Fagan admitted that they have not performed any analyses around the cost of battery storage **in New Orleans** or whether it could effectively meet **ENO's** peaking needs.[51] On the other hand, Mr. Cureington explained at hearing that the Company analyzed battery storage technology in the 2015 IRP, but those technologies were screened out as not being cost effective or meeting the identified needs.[52] He went on to explain that "we don't believe that batteries are an alternative to NOPS simply because they're nothing more than a way to store electricity. They still require a source of generation, and once the battery has been discharged, you no longer have any energy unless you

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[48] Tr. (Fagan) 12/19/17, at 14-16; Tr. (Stanton) 12/21/17, at 11-12. In fact, Dr. Stanton admitted that she did not even know what other local resource zones are in MISO South other than Zone 9. Tr. (Stanton) 12/21/17, at 15.

[49] Tr. (Fagan) 12/19/17, at 25-26, 36; Tr. (Stanton) 12/21/17, at 23.

[50] Tr. (Stanton) 12/21/17, at 25-26.

[51] Tr. (Fagan) 12/19/17, at 36; Tr. (Stanton) 12/21/17, at 24-25.

[52] Tr. (Cureington) 12/18/17, at 140.

have another source of generation to charge it. So it would not have met the identified needs."[53] Mr. Cureington also explained that batteries were considered again at the request of the Advisors and by Council Resolution in the November 2016 Supplemental analysis, Case 4, but the results again indicated that they were not cost-effective.[54] That said, while battery storage is not a viable alternative to meeting the specific identified need for long-term dispatchable capacity that ENO is currently trying to address, the Company recognizes the potential that battery storage may provide in the future to meet other needs, and to that end the Company is engaged in a solar/battery pilot program to assess the future potential of that technology.[55]

Finally, while the transmission-only portfolio modeled in the Company's Reference Cases appears cost-effective under a reduced capacity price sensitivity, as Mr. Cureington explains, transmission investment is not a viable option. He testified that the transmission-only case understates the Total Relevant Supply Costs because it is essentially a "do-nothing" approach in which transmission upgrades are made solely to maintain North American Electric Reliability Corporation ("NERC") reliability requirements to the exclusion of meeting other resource needs, such as securing a stable price for the power that flows through those transmission lines.[56] To be clear, transmission does not equal MWs, it does not address the additional reliability concerns, as discussed more fully below, and it does not address the market- and supply-related risks discussed by Mr. Cureington.[57]

For example, transmission does not address the significant risk to customers associated with undue exposure to the short-term market price for capacity in MISO, which, as explained in

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53 *Id.* at 177.

54 *Id.* at 140; ENO Exhibit Cureington-4 (Cureington Supplemental Direct) at 7-8, 13.

55 Tr. (Cureington) 12/18/17, at 224.

56 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 29.

57 *Id.* at 20-25, 29.

more detail below, is expected to significantly increase as the current capacity surplus in MISO declines over the next five years and becomes a deficit beyond those five years. Thus, a transmission-only scenario would hitch the City's wagon to volatile one-year markets; and accordingly reflects a risky gamble that the capacity surplus will continue, capacity prices will remain low, market- and supply-related risks will not materialize, and none of the aging in-region generation necessary to support reliability in New Orleans will deactivate early. Such a chain of assumptions is contrary to the Company's reasoned expectations and analyses. Moreover, as Mr. Cureington testified, even if transmission projects were undertaken to facilitate additional import capability into Amite South and DSG, as the capacity surplus declines there may not be excess capacity to purchase.[58] Effectively, the transmission-only scenario does not address ENO's specific needs and would leave ENO's customers exposed to significant risks (*i.e.*, increased costs and outages).

In summary, ENO has conducted numerous economic and other analyses over the last several years, all of which have confirmed that a dispatchable, peaking resource located in New Orleans East is the best alternative for meeting its identified and significant overall and peaking and reserve long-term capacity need, and that NOPS is cost-effective. Renewable resources cannot meet the identified need because they are not dispatchable, and, in any event, could not likely be located in New Orleans East, where the capacity is needed. Transmission investment cannot meet the need because it does not produce power, it does not address reliability concerns, and it does not mitigate market- and supply-related risks.

3. *Opposing parties propose a number of speculative and unreasonable assumptions intended to erode the Company's capacity need and undermine the Company's reasoned economic analysis—all to make a transmission-only solution look more attractive.*

58 *Id.* at 30.

In contrast to the extensive analyses produced by the Company over the last several years, the Joint Intervenors' witnesses (Dr. Stanton and Mr. Fagan) have not conducted any analysis that produced a recommended portfolio of alternatives that can be compared to NOPS on a total supply cost basis.[59] In fact, Mr. Fagan admitted at hearing that he did not conduct any production cost modeling or capacity expansion modeling.[60] Surprisingly, neither Dr. Stanton nor Mr. Fagan ever deemed it important enough to review ENO's 2015 IRP prior to forming their conclusions and drafting their testimony.[61] Instead, those witnesses cited macro-level information not specific to ENO, its service area, or its unique planning circumstances as the basis for recommending a number of risky alternatives and criticisms of ENO's analyses, the effect of which would reduce ENO's identified capacity need and alter the Company's economic analyses such that transmission upgrades appear to be cost-effective (yet still ignoring ENO's unique planning circumstances and other benefits of local, dispatchable resources like NOPS). To perform these manipulations, the Joint Intervenors' witnesses altered reasonable assumptions in order to lower ENO's load and the price of capacity in the MISO market. They performed these alterations based on pure speculation. As discussed below, however, these manipulations amount to mere smoke and mirrors that attempt to bolster transmission upgrades that cannot be constructed, and would not solve the suite of current reliability needs even if they were constructed. Dr. Stanton and Mr. Fagan's motives are apparent given their anything-but-a-gas-plant approach to resource planning; and it is clear that their opinions and recommendations should be disregarded because they are unreasonable, unsupported by analysis, and shift all of the tremendous risks to ENO's customers.

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59 Tr. (Fagan) 12/19/17, at 19-21; Tr. (Stanton) 12/21/17, at 20.

60 Tr. (Fagan) 12/19/17, at 17.

61 *Id.*; Tr. (Stanton) 12/21/17, at 12.

a. The opposing parties urge unreasonable decrements to ENO's peak load forecast.

i. DSM Effects

To begin, Dr. Stanton and Mr. Fagan admitted at the hearing that they do not have any complaints about the fundamental methodology used by ENO to forecast its peak load[62] and that they did not provide any alternative load forecast of their own.[63] In fact, Mr. Fagan admitted that he has never created a load forecast for resource planning,[64] but he and Dr. Stanton nevertheless chose to offer various recommendations that would have the effect of decrementing ENO's peak load forecast in a way intended to erode ENO's identified long-term capacity need. It should be noted that while this may be a fun theoretical exercise for the Joint Intervenors' witnesses, one effect of their manipulations could very well be that the Company and its customers will not plan for load that will in fact materialize, which has a host of negative consequences. Indeed, the MISO Independent Market Monitor ("IMM") recently noted that most utilities in MISO have tended to maintain a small surplus over their minimum requirements because the "costs of being deficient are large."[65]

One of those primary ways that the Joint Intervenors reduce ENO's load is by including the effects of achieving the Council's 2% kWh DSM goal in its load forecast.[66] Of course, Dr. Stanton offered no reasonable basis upon which ENO, the only party that has an obligation to serve load, could assume that achieving the 2% DSM goal in New Orleans is achievable and sustainable, let alone cost effective.[67] To be clear, the Company supports the Council's 2% DSM

62 Tr. (Fagan) 12/19/17, at 21; Tr. (Stanton) 12/21/17, at 20-21.

63 Tr. (Fagan) 12/19/17, at 20; Tr. (Stanton) 12/21/17, at 21.

64 Tr. (Fagan) 12/19/17, at 23.

65 ENO Exhibit Cureington-8 (Cureington Rebuttal) at Exhibit SEC-15, p. 16.

66 Joint Intervenors Exhibit Stanton-2 (Stanton Direct) at 13-14.

67 Tr. (Stanton) 12/21/17, at 28.

goal, but recognizes that it is extremely aggressive, that no party in this case can guarantee it will be achieved, and that it would warp the results of any resource planning that relies on it as a basis for judging the amount of load that is expected to materialize.

Dr. Stanton admitted at the December 2017 Hearing that she did not conduct any analysis of the DSM potential in New Orleans.[68] Her recommendation is instead based on a misunderstanding of the Council's 2% goal itself, as well as irrelevant comparisons to the DSM savings achieved by a handful of other states, particularly in the Northeast.[69] First, as Mr. Cureington explained, the Council has set an aspirational goal that targets an increase in savings of 0.2% per year until such time as the programs generate 2% kWh savings per year.[70] However, he further explained that the goal is a *target*, not a mandate.[71] Importantly, the Council requires that cost-effectiveness testing be used to develop Energy Smart program savings targets and implementation budgets.[72] Mr. Cureington explained that this requirement acts to protect customers from paying for efficiency programs where costs exceed expected benefits.[73] In reality, the Company is currently in its seventh year of energy efficiency program implementation, and at the end of Program Year 6 it had achieved approximately 0.34% annual savings, consistent with prior years despite increased program budgets.[74] Thus, while the

68 *Id.* at 22.

69 Joint Intervenors Exhibit Stanton-2 (Stanton Direct) at 13-14, 32-34.

70 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 29.

71 *Id.*

72 Resolution R-09-267 at 3 ("Whereas, all programs approved by the Council, with the exception of low income weatherization and domestic solar water heater programs, must be determined to be cost-effective under the industry accepted testing criteria of the Total Resource Cost ("TRC") Test and the Program Administrator Cost ("PAC") Test as defined in the California Standard Practice Manual, "Economic Analysis of Demand-Side Programs and Projects," October 2001.").

73 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 29.

74 *Id.*

Company continues to target the goal, achieving the goal, which represents an increase of just under 500%, in a cost-effective manner is another matter entirely.

Second, comparisons to the DSM savings levels achieved in other, primarily Northeastern states (Massachusetts, Vermont, and Rhode Island), are not relevant to assessing the DSM potential in New Orleans. Mr. Cureington explained that DSM savings can be affected by different utility avoided costs, different retail rates, different maturity in energy efficiency work force, and different customers mixes.[75] At the December 2017 Hearing, Dr. Stanton agreed that different avoided costs and retail rates in particular can affect actual DSM savings levels.[76] Yet, there is no evidence that Dr. Stanton attempted to determine whether ENO is comparable to any of those higher-achieving states in her analysis. To the contrary, the evidence indicates that the level of DSM savings actually achieved by states in geographic proximity to Louisiana is much lower: Oklahoma (0.39%), Missouri (0.39%), Georgia (0.27%), Mississippi (0.26%), Tennessee (0.19%), Texas (0.19%), Florida (0.11%), Louisiana (0.10%), and Alabama (0.06%).[77] Accordingly, the suggestion that ENO should assume that it can cost-effectively achieve DSM savings at the 2% level in its load forecast simply because Dr. Stanton believes that the Council so ordered or because a handful of other Northeastern states have done so is misplaced. Rather, the reasonable approach is to use assumptions based on DSM savings actually achieved in New Orleans.

Third, the Company retained Navigant Consulting to assess the achievability and cost-effectiveness of the Council's 2% kWh goal. Navigant concluded in its report that, while it is possible, in academic theory, to achieve 2% savings from energy efficiency measures in New

[75] *Id.* at 31.

[76] Tr. (Stanton) 12/21/17, at 23.

[77] ENO Exhibit Cureington-8 (Cureington Rebuttal) at Exhibit SEC-20.

Orleans,[78] the assumptions required to force their proprietary Demand Side Management Simulator (DSMSim™) model to solve for 2% annual savings in New Orleans were theoretical and required Navigant to relax industry standard thresholds for cost-effectiveness, incentive levels, administrative costs, and market saturation and further assume that new measures not in existence today will be invented and available at some unknown future date.[79] Under those highly theoretical and arguably unreasonable assumptions, Navigant essentially forced its model to produce the 2% aspirational goal and estimated a price tag of **$2.3 billion** over the planning horizon.[80] Using such assumptions in ENO's long-term resource planning is obviously not reasonable, and it is inconsistent with Dr. Stanton's own assertion that the "more modern approach" to resource planning is to emphasize the acquisition of *cost-effective* supply- and demand-side resources.[81]

In a similar vein, both Dr. Stanton and Mr. Fagan recommend that ENO should have used at least Navigant's "High Case Achievable Scenario" savings level of 0.85% in calculating its peak load forecast, which represents an increase from current savings of approximately 150%.[82] The record is clear, however, that neither Dr. Stanton nor Mr. Fagan conducted any analysis of the DSM potential **in New Orleans**,[83] and their suggestions indicate a misunderstanding of Navigant's analysis. As Mr. Cureington explained, the Navigant analysis included three scenarios for evaluation, starting with a High Case Achievable scenario to establish the ceiling for cost-effective long-run energy efficiency potential in New Orleans, against which the

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78 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at Exhibit SEC-14.

79 *Id.*

80 *Id.*

81 Joint Intervenors Exhibit Stanton-2 (Stanton Direct) at 10-11.

82 *Id.* at 31-32; Joint Intervenors Exhibit Fagan-2 (Fagan Direct) at 16, 32.

83 Tr. (Fagan) 12/19/17, at 22-23.

remaining two scenarios could be compared.[84] As the description implies, the High Case Achievable Scenario represents "Navigant's best judgment regarding a level of [energy efficiency ("EE")] potential that would be achievable with an aggressive roll-out of EE programs."[85] In fact, Navigant's three scenarios (high case achievable, theoretical achievable with known measures, and theoretical achievable with known and unknown measures) were intended to assess the feasibility of the Council's 2% goal by starting with the maximum long-run achievable potential that may be possible under aggressive assumptions.[86] Consistent with the Company's Reference Portfolios, reference scenarios are typically calibrated to historical program penetration and existing program spend levels.[87] Thus, when considered in that context, Navigant's High Case Achievable is not a floor for incorporation into prudent long-term resource planning, but rather a ceiling more appropriate for consideration as an aspirational goal.[88] For that reason it would not be appropriate for ENO to utilize such a high case, "potential" EE savings level in calculating the realistic amount of load that it will likely have to serve.

In addition, timing is an issue. Mr. Cureington explained at hearing that there is no basis upon which to conclude that DSM can meet the need that exists *today* because DSM takes time to accumulate.[89] He went on to explain that "all of the studies that have been conducted for us show that while there is potential, it would take a very long time to achieve – more specifically, 10 to 20 years in order to get to the level of demand response that we need to even get close to

84 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 29.

85 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at Exhibit SEC-14, p. 19.

86 *Id.* at 34.

87 *Id.*

88 *Id.*

89 Tr. (Cureington) 12/18/17, at 213.

the needs we've identified."[90] Thus, assuming some incremental level of DSM were cost-effective, achievable, and sustainable, there is no basis upon which to conclude it could meet the needs that that must be addressed today. ENO does not have the luxury of waiting 20 years to see if hypothetical, cost-effective DSM materializes.

In contrast to Dr. Stanton's and Mr. Fagan's speculative approach, and consistent with ENO's obligation to serve whatever load actually materializes, which is not an obligation shared by opposing parties,[91] ENO included in its load forecast the effects of Energy Smart programs through Program Year 6, the last full year for which data is available, based on the effects those programs actually had on billed sales.[92] To make additional, speculative, decrements would be unreasonable because embedded within ENO's load forecast are the estimated effects on the Company's sales and peak demand associated with a range of factors that are inherently uncertain.[93] Those factors include savings from Company-sponsored energy efficiency programs, historical customer behavior, historical voluntary customer efficiency investments, and historical performance of customer investments in behind-the-meter ("BTM") technologies (*e.g.*, smart thermostats and rooftop solar).[94] The assumption that those improvements, investments and behaviors will continue to provide the same levels of sales and peak demand reduction over a long-term planning horizon, especially considering the continued growth in customer count, is uncertain and requires ongoing sustained investments.[95]

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90 *Id.*

91 Tr. (Fagan) 12/19/17, at 20; Tr. (Stanton) 12/21/17, at 13.

92 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 51.

93 *Id.* at 52.

94 *Id.*

95 *Id.*

As Mr. Cureington explains, the Company's forecast also includes an annual reduction in projected sales that reaches 1.5% in 2022 to account for the anticipated but uncertain effects of the proposed deployment of advanced metering infrastructure ("AMI") across the Company's service area, which docket is still pending before the Council.[96] In fact, Dr. Stanton agreed at the December 2017 Hearing that the potential effects of AMI are uncertain.[97] While, as Dr. Stanton and Mr. Fagan note, the Company did file an implementation plan designed to target an increased level of savings for Program Years 7 – 9 of Energy Smart, those goals are significantly higher than the savings results the Company has achieved through the first six years of Energy Smart despite annual increases in program spending.[98] Dr. Stanton agreed at hearing that the actual level of savings that may be achieved from DSM programs are uncertain.[99] Thus, it would be unreasonable to make additional decrements for the potential effects of those programs when they remain unproven, are more than double the Company's actual experience, and are considerably higher than savings levels achieved by other states in the region.[100]

It is also important to note that, as Mr. Cureington explains, the Company's load forecast does not include any adjustments for potential **increases** that could materialize if the economy expands more strongly than forecasted, which could increase growth in customer count, load, or both.[101] The forecast also does not include the potential for adoption by customers of electric vehicles ("EVs") that would increase the Company's load as those vehicle's batteries are

[96] *Id.*

[97] Tr. (Stanton) 12/21/17, at 21-22.

[98] ENO Exhibit Cureington-8 (Cureington Rebuttal) at 52.

[99] Tr. (Stanton) 12/21/17, at 21.

[100] ENO Exhibit Cureington-8 (Cureington Rebuttal) at Exhibit SEC-20.

[101] *Id.* at 53.

charged.[102] The forecast also assumes that existing rooftop solar will continue providing the same level of load reduction over the planning horizon, which does not account for degradation in the production of solar panels over time, and also assumes customers will continue maintaining their systems in good operating condition and minimize shading from adjacent vegetation.[103]

The Company's load forecast also does not account for potential decreases in the rated capacity of existing resources. For example, Mr. Cureington explained that, for upcoming Planning Year 2018-2019, the Company will recognize a 21 MW reduction in available generating resources due to a newly calculated generator verification ("GVTC") tests for the Company's Power Block 1.[104] Ultimately, when compared to the Company's electrical load, this results in an unexpected reduction in available capacity that is not reflected in the current load forecast and negates approximately half of the reduction in the load forecast that occurred between the time this NOPS application was originally filed and the current load forecast.[105]

In summary, the Company's load forecast already assumes reductions in future demand associated with historical factors, changes in customer behavior, and prospective investments that are not certain to continue providing the estimated savings over a long-term planning horizon, but the Company has assumed they will continue and are included in the current load forecast. Including ***additional*** reductions based on speculative, best-case scenarios proposed by Dr. Stanton and Mr. Fagan would not be reasonable and would expose the Company's customers

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102 It is worth noting that on September 28, 2017 the Council adopted Ordinance No. 31953, which ordained changes to Code of the City of New Orleans providing for the requirements to permit the installation of curbside EV charging stations in public right of way. On October 11, 2017, the Mayor approved and returned the Ordinance, and in accordance with Section 3-113(2) of the Home Rule Charter, the Ordinance became effective on October 9, 2017.

103 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 53-54.

104 *Id.* at 54.

105 *Id.*

to price risks in the market as well as reliability risks if the speculative decrements do not materialize as assumed, which is discussed below.

ii. Behind-the-Meter Solar

Dr. Stanton's and Mr. Fagan's second line of attack with respect to their manipulations is that the Company's projections of continued growth in BTM solar are understated and, accordingly, the Company should assume a greater reduction in peak load occasioned by additional BTM growth.[106] Both Dr. Stanton and Mr. Fagan admitted at the December 2017 Hearing that they did not conduct any analysis of the potential for continued BTM solar growth or the associated costs **in New Orleans**.[107] Had they done the research, they would have discovered that the Company's assumption that the rate of BTM solar installations will not continue at historical rates is based on the unique circumstances that led to the remarkable growth of rooftop solar in New Orleans over the last few years as well as the uncertainty around whether customers who do not yet have rooftop solar will be willing to pay more than past customers as those circumstances change.[108]

As explained by Mr. Cureington, the initial growth was spurred by state and federal tax credits that were combined to cover up to 80% of the cost of a typical rooftop solar system as well as a net metering tariff that paid customers for any excess energy sent back to the grid at the full retail rate.[109] Dr. Stanton admitted that she was unfamiliar with the net metering rate schedule for New Orleans.[110] Those conditions have changed, and, as Mr. Cureington testified,

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106 Joint Intervenors Exhibit Stanton-2 (Stanton Direct) at 15-19; Joint Intervenors Exhibit Fagan-2 (Fagan Direct) at 12-13.

107 Tr. (Fagan) 12/19/17, at 26, 36; Tr. (Stanton) 12/21/17, at 23-25.

108 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 38.

109 *Id.* at 39.

110 Tr. (Stanton) 12/21/17, at 23-24.

average monthly interconnections in New Orleans have fallen by around 86% in 2017 compared to their peak in 2013, and, through August 2017, ENO has averaged only around 26 interconnections per month.[111] Additionally, a pending trade case before the International Trade Commission, which was ignored by both Mr. Fagan and Dr. Stanton, presents the solar industry with the potential for a significant increase in the cost of solar panels, which would further depress demand for residential rooftop systems concurrently with the elimination of state incentives and phase-out of federal solar tax incentives that begins in 2020.[112]

Going forward, the Company reasonably expects that the number of new installations will continue to decrease to a *de minimis* point following expiration of the existing state tax credit at the end of 2017 (and that is currently only available to solar leasing companies) and the phase-down of federal tax credits that will begin in 2020 and, ultimately, will significantly reduce the subsidies to customers and installation companies.[113] And even if the demand for new residential rooftop solar does not decline to zero, assuming some small number of installations each month would not have a material effect on the Company's analysis. As Mr. Cureington explains, the average size of residential rooftop solar systems being installed in New Orleans is about 5 kW, so a small number of new installations each month going forward, regardless of whether its zero or something slightly higher, would not have a meaningful impact on the Company's long-term resource needs.[114] Accordingly, the Company's assumptions with respect to BTM growth in New Orleans are reasonable, and additional proposed decrements amount to

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[111] ENO Exhibit Cureington-8 (Cureington Rebuttal) at 40.

[112] *Id.* at 44.

[113] *Id.* at 40.

[114] *Id.* at 44-45. Mr. Cureington explained that it would take approximately 400 residential solar installations to offset 1 MW of peak capacity. *Id*. at 44.

nothing more than risky speculation asserted by witnesses with no understanding of conditions in New Orleans, Louisiana, or MISO South.

iii. ENO's Commitment to 100 MW of Solar Resources

Dr. Stanton's argument that ENO's projected capacity deficit is overstated because it does not account for ENO's commitment to 100 MW of solar resources is misleading,[115] and it would be inappropriate to evaluate the Company's long-term need as Dr. Stanton suggests. First, Dr. Stanton is focused solely on the first 10 years of the planning horizon in which, if those planned solar resources were counted as existing capacity (even though they are not existing capacity), the indicated capacity deficit would be around 50 MW instead of around 100 MW in 2026. As Mr. Cureington explained, however, a prudent resource planner must consider the entire planning horizon over which resource needs have been identified.[117] In this case, that period is 20 years, and as shown in Mr. Cureington's analysis, including **both** the 100 MW of planned solar resources and the 128 MW RICE units results in a capacity **deficit** at the end of the 20-year period of 70 MW.[118] Building the CT instead, but still including the solar resources, results in a small capacity surplus of only 28 MW at the end of the 20-year planning horizon.[119] Thus, ENO's long-term capacity need is real and not overstated.

Second, Mr. Cureington explained that carrying some excess capacity during the planning period is not unreasonable.[120] What is unreasonable is to expect that resource additions can be perfectly matched to resource needs regardless of the technology under consideration,

115 Joint Intervenors Exhibit Stanton-2 (Stanton Direct) at 11-12.

117 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 50; Tr. (Cureington) 12/18/17, at 188.

118 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending) at Exhibit SEC-11.

119 *Id.*

120 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 50.

with which Advisors witness Mr. Joseph W. Rogers agrees.[121] Dr. Stanton even admitted that she is not aware of any utility that is able to exactly match its load and physical supply.[122] In the case of NOPS, the Company has proposed two viable alternatives for the Council's consideration, where the CT would be expected to meet and slightly exceed the Company's need over the planning horizon, and the RICE units would be expected to only meet that need for the first half of the planning horizon and thereafter leave the Company short. The selection of either option for NOPS would be a prudent way to meet the overall need for capacity, as well as mitigate the substantial peaking and reserve deficit.[123] Further, the additional capacity associated with the larger CT option would provide additional benefits to mitigate market- and supply-related risks, which is reasonable in consideration of ENO's unique planning circumstances, and the smaller RICE units would provide similar benefits over the first half of the planning horizon. The Joint Intervenors ignore those benefits and ENO's unique planning circumstances.

Finally, as Mr. Cureington explained, including the solar resources as "existing resources" in the Company's load and capability forecast is not reasonable because, although the Company is committed to adding up to 100 MW of solar resources to its portfolio, the timing and location of those resources are uncertain.[124] Mr. Cureington explained at hearing that in response to the RFP that was issued in 2016 for up to 100 MW of solar, the Company has received [redacted] MW of proposals, but only [redacted] MW of that would be located in New Orleans.[125] And at this time only [redacted] MW out of the 100 MW are under negotiations for contracts,[126] meaning none of it has

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121 Advisors Exhibit Rogers-2 (Rogers Direct) at 33.

122 Tr. (Stanton) 12/21/17, at 22.

123 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 49.

124 *Id.*

125 Tr. (Cureington) 12/18/17, at 327.

126 *Id.*

been built. Thus, it would not be reasonable, at this premature stage, for ENO to have included 100 MW of solar resources as existing capacity.

More important is that, regardless of location and timing, Mr. Cureington explained that solar resources simply will not meet the Company's peaking capacity need: "with a solar resource, because it relies on the sun to generate electricity, we can't rely on it all the time; whereas, with NOPS, you'll have it at your disposal or MISO would have [it at] their disposal to dispatch whatever is needed, whether it's because of an unplanned transmission outage, an unplanned generator outage, or a really hot or cold day where the line loading exceeds the capability to import capacity into the load pocket, all of which, you know, would benefit customers."[128]

b. The opposing parties offer unreasonable speculation to manipulate future MISO capacity prices in an attempt to undermine the Company's economic analyses.

One of the components of the Company's economic analysis is a projection of future MISO PRA clearing prices. The Company's forecast assumes that as equilibrium occurs (where capacity supply and demand are in balance) and excess capacity in the market tightens, capacity prices in MISO will trend upwards and eventually equal the cost of new entry ("CONE").[129] This is the law of supply and demand, pure and simple. Air Products witness Maurice Brubaker confirmed at hearing that as equilibrium approaches, "it's generally believed that the cost of new entry or CONE is going to set the price in the future."[130] And the cost of new entry simply means the cost of a new build CT. To her credit, Dr. Stanton conceded that capacity prices would rise if

128 Tr. (Cureington) 12/18/17, at 327-328.

129 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 39.

130 Tr. (Brubaker) 12/20/17, at 174.

the surplus decreases.[131] And she also agreed that deactivations will reduce the surplus,[132] which Mr. Brubaker also confirmed.[133] However, Mr. Fagan and Dr. Stanton took the position in their Direct Testimony that equilibrium is unlikely to occur, and as a result, capacity prices in MISO will remain low.[134] At the December 2017 Hearing, however, Dr. Stanton clarified that she is not offering any opinion on MISO capacity prices and defers entirely to Mr. Fagan on these issues.[135] Mr. Fagan admitted that he undertook no effort to calculate future MISO capacity prices;[136] he is merely criticizing the Company's projections.

Mr. Fagan's position that the current surplus will continue indefinitely is contrary to the credible evidence, rests on unwarranted speculation about potential future projects that may be constructed by other utilities in MISO over which neither the Company nor the Council has any control, and unreasonably relies on historical PRA clearing prices that are not indicative of the future and are influenced by a flawed capacity market and a current capacity surplus. First, the primary data relied upon by Mr. Fagan is the 2017 OMS MISO Survey ("Survey").[137] That Survey, which is simply a survey completed by utilities regarding their potential construction plans for the next five years, forecasts a surplus of committed capacity in MISO Zone 9, where ENO is located, of only 200 MW in 2022.[138] As Mr. Cureington explains, the early deactivation of just one of the legacy gas units in Zone 9 would turn that surplus into a deficit earlier than

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131 Tr. (Stanton) 12/21/17, at 17.

132 *Id.*

133 Tr. (Brubaker) 12/20/17, at 175.

134 Joint Intervenors Exhibit 4-5 (Fagan Direct) at 4; Joint Intervenors Exhibit Stanton-2 (Stanton Direct) at 38.

135 Tr. (Stanton) 12/21/17, at 13.

136 Tr. (Fagan) 12/18/17, at 30.

137 Joint Intervenors Exhibit Fagan-2 (Fagan Direct) at 17-18.

138 ENO Exhibit Cureington-8 (Cureington Rebuttal) at Exhibit SEC-16, p. 15. "Committed Capacity Resources" are "Resources within the MISO footprint committed to serving demand, based on survey responses." *Id.* at 17.

expected.[139] And there are over 3,200 MW of aging legacy resources in Zone 9 that could deactivate earlier than anticipated.[140] Moreover, as Mr. Cureington explains, that Survey, like the years before, continues to show that the current surplus is declining dramatically over the next five years.[141] Again, as the surplus declines, the price of buying short-term capacity in the market will rise significantly. And, looking beyond those initial five years, MISO's 2017 Resource Adequacy Report, discussed below, projects a deficit in 2023 and the years beyond, showing that the declining trend will continue unless utilities like ENO act responsibly to construct generation to meet their needs.

Mr. Fagan, however, ignores the importance of such a narrow committed capacity margin and would have the Council focus instead on what the Survey indicates to be "potential" capacity additions in MISO that he asserts would stave off equilibrium and keep short-term capacity prices low. The fallacy of his position is that he offers no evidence of the likelihood of any of that potential new capacity being constructed, whereas Mr. Cureington explained that the amount of "Potential New Capacity" included in the Survey is just an arbitrary number picked by MISO.[142] In other words, there is no likelihood of construction attached to it, and neither ENO nor Mr. Fagan have any way of knowing if or when any of it will ever be built. Further, Mr. Cureington pointed out that the amount of "potential" capacity cited by Mr. Fagan as new projects includes existing units that are exploring retirement but have not yet fully committed to deactivation.[143] Put another way, Mr. Fagan, a resident of Massachusetts, is suggesting that New Orleanians and the Council rely on the fact that units actively exploring deactivation might

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[139] ENO Exhibit Cureington-8 (Cureington Rebuttal) at 15.

[140] *Id.* at 15, 18.

[141] *Id.* at 14-15.

[142] *Id.* at 16.

[143] *Id.* at 17.

potentially continue operations a little longer instead. Mr. Fagan's suggestion is akin to placing a bad bet with someone else's money. ***Closing one's eyes to risk and hoping for the best is not prudent resource planning.***

Mr. Fagan also failed to conduct any analysis of the types or ages of capacity resources in MISO South,[144] which, as explained above, include over 3,200 MW of aging generation that could retire early and hasten equilibrium in MISO South in particular. In essence, Mr. Fagan is asking the Council to bet that unknown generation projects over which the Council has no control will be built (and if built, timely built), and that units that are exploring retirement and over which the Council has no control will continue operations. He is also asking the Council to ignore the possibility that aging resources in MISO South could retire early (like the Michoud units did) and quickly turn the existing capacity surplus in MISO South into a deficit. As Mr. Cureington explained, those are very risky assumptions, which neither the Company nor any prudent resource planner would be willing to make.[145]

Moreover, the Company's projection of equilibrium occurring around 2022 is consistent with highly credible sources. The 2017 MTEP Resource Adequacy Report (Book 2) cited by Mr. Fagan projects an overall MISO capacity **deficit** of 1,400 MW in 2023, which grows to a 2,500 **deficit** MW in 2028.[146] And it is important to understand that this is MISO's own projection of resource adequacy. MISO's projection is corroborated by the 2016 NERC long-term reliability assessment, which states that "MISO is currently projected to fall below their target of 15.20 percent to an Anticipated Reserve Margin of 13.89 percent in 2022 and continue

144 Tr. (Fagan) 12/19/17, at 27.

145 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 17.

146 *Id.* at Exhibit SEC-17, p. 14, Table 6.2-1.

to decrease to 9.07 percent by the year 2026."[147] The MISO IMM provided its view that "the system's resources should be adequate for summer 2017 if the peak demand conditions are not substantially hotter than normal. However, planning reserve margins have been decreasing and will likely continue to fall as resources retire and suppliers continue to export capacity to PJM."[148] Finally, IHS Markit ("IHS"), a globally recognized firm that provides insight and analysis of major industries and markets, produces an annual capacity value forecast for MISO, which also indicates sharply increasing capacity prices in MISO beginning in 2022,[149] and which is more evidence of the current capacity surplus rapidly declining to a deficit.

Accordingly, the Company submits that it is the more reasonable approach to rely upon MISO's, NERC's, the MISO IMM's, and an independent industry analyst's projections of the MISO capacity market, which corroborate the assumptions used in the Company's economic analyses, not Mr. Fagan's rank speculation about potential unknown projects continuing in perpetuity into what is unquestionably a shrinking capacity surplus in MISO. Moreover, if Mr. Fagan's speculation does not pan out, Mr. Cureington explained that ENO would find itself without sufficient capacity to serve its load at a time when capacity prices are rising and building any new capacity would entail a multi-year lead time.[150] Mr. Brubaker also confirmed that the cost of new resources could include a premium if supply is constrained.[151] That is simply not a reasonable approach to long-term resource planning.

Mr. Fagan also points to the historically low MISO PRA clearing prices as evidence of a continuing capacity surplus. Several flaws underlie such reasoning. First, both Mr. Cureington

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[147] *Id.* at Exhibit SEC-18, p. 3.

[148] *Id.* at Exhibit SEC-15, p. 12.

[149] *Id.* at Exhibit SEC-19.

[150] ENO Exhibit Cureington-8 (Cureington Rebuttal) at 19.

[151] Tr. (Brubaker) 12/20/17, at 173.

and Advisors witness Mr. Rogers stressed that it is not reasonable to rely on short-term annual purchases of capacity credits through the PRA to address long-term resource needs.[152] Second, it is illogical to assume that one year's clearing price is any indication of the next year's price. The PRA is an annual market; therefore, the Auction Clearing Price ("ACP") in a given planning year reflects the balance of supply offers (capacity) and demand requirements (peak load) in that year.[153] As Mr. Cureington explained, "historical auction clearing prices are not an indication of future auction clearing prices. They are just an indication of the dynamics of the market in the year in which that auction was conducted."[154] And those dynamics change annually and sometimes dramatically. For example, for the 2015/2016 planning year the ACP for Zones 2-3 and 5-7 was $3.48/MW-day, which ACP increased to $72/MW-day for the 2016-2017 planning year.[155] Similarly, the market observed Zone 4 spike to $150 in 2015-2016, which was nearly ten times the 2014-2015 price of $16.75.[156] Even Mr. Fagan agreed at hearing that MISO capacity prices can be volatile.[157] It is this very problem that a local, dispatchable generator can provide a hedge against.[158]

Third, it is not surprising that, in general, historical PRA clearing prices in MISO South have been low. It is undisputed that there is *currently* a capacity surplus in MISO. But the evidence shows that this situation is not expected to exist in perpetuity; rather, as indicated by MISO, NERC, the MISO IMM, and IHS, the capacity surplus in MISO is expected to decline over the next five years. When a capacity deficit exists, it is reasonable to expect capacity prices

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152 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 22; Advisors Exhibit Rogers-2 (Rogers Direct) at 32.

153 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 22.

154 Tr. (Cureington) 12/18/17, at 205.

155 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 22.

156 *Id.*

157 Tr. (Fagan) 12/19/17, at 29.

158 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 22.

in the MISO PRA to approach, if not equal, new build prices.[159] This change can happen suddenly, as evidenced above, and if unhedged, customers will remain exposed to high prices until new generation is constructed, which can take years.

Fourth, according to the MISO IMM 2016 State of the Market Report, "[t]he demand for capacity in the PRA continues to poorly reflect its true reliability value, which undermines its ability to provide efficient economic signals for investment and retirement decisions."[160] In particular, in discussing the flaws with the MISO capacity market, the IMM Report states:

> The third issue with MISO's current capacity market relates to definitions of local resource zones. Currently, a local resource zone cannot be smaller than an entire [Local Balancing Authority ("LBA")]. However, capacity is sometimes needed in certain load pockets within LBAs. A good example of this type of requirement is the Narrow Constrained Areas (NCAs) in MISO South where ***the addition of fast-start capacity would be extremely valuable***. Hence, we recommend that MISO's local resource zones be established based primarily on transmission deliverability and local reliability requirements.[161]

At the very core of this proceeding, ENO is asking the Council to approve the construction of just that: a fast-start resource to meet the Company's long-term needs and support grid reliability in New Orleans, which, as the IMM states, will be extremely valuable. Mr. Fagan, on the other hand, admitted at hearing that he did not review the IMM Report in developing his opinions and conclusions,[162] that he was not familiar with narrow constrained areas in MISO South,[163] and that he did not know whether New Orleans was in a narrow constrained area.[164]

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159 Tr. (Brubaker) 12/20/17, at 174; Exhibit ENO Cureington-6 (Cureington Supplemental and Amending Direct) at 16.

160 ENO Exhibit Cureington-8 (Cureington Rebuttal) at Exhibit SEC-15, p. 15.

161 *Id.* at Exhibit SEC-15, p. 18 (emphasis added). Amite South, including DSG and the ENO service area, is one of the NCAs in MISO South where the addition of quick-start resources would be "extremely valuable."

162 Tr. (Fagan) 12/19/17, at 30-31.

163 *Id.*, at 31.

164 *Id.*

This makes it clear that Mr. Fagan simply has no reasonable understanding of ENO's unique planning circumstances or conditions in MISO South.

For these reasons, the Company also disagrees that Advisors witness Mr. Rogers's sensitivity analysis using a $6/kW-year capacity price that remains essentially flat over the 20-year planning horizon provides useful information.[165] That approach assumes equilibrium will never be achieved and is contrary to the projections of MISO, the MISO IMM, IHS, and NERC; it also ignores that past PRA clearing prices are meaningless in terms of trying to predict future clearing prices, particularly as the capacity surplus declines. Accordingly, Mr. Rogers's sensitivity analysis, which results in the transmission-only scenario appearing more cost-effective than NOPS, should not be afforded any weight.

The final problem with Mr. Fagan's overall approach is that he essentially recommends that ENO should rely on the MISO short-term capacity market in lieu of a long-term capacity resource. In fact, he goes so far as to state that "ENO can and should rely upon surplus MISO South resources"[166] to "exploit" the market.[167] This position is oxymoronic, however, because it of course assumes, against all credible evidence, that the current surplus will continue indefinitely because other utilities and their regulators will act responsibly with respect to resource planning and not, as he suggested, "exploit" the market themselves. As Mr. Cureington and Mr. Brubaker explain, when prices rise, it will take several years to obtain regulatory approval and construct new units, during which time customers will be exposed to high capacity prices that could have been avoided but for an ill-fated attempt to "exploit," *i.e.*, gamble with, the

165 Advisors Exhibit Rogers-2 (Rogers Direct) at 44.

166 Joint Intervenors Exhibit Fagan-2 (Fagan Direct) at 31.

167 *Id.*

market.[168] This risky strategy also begs the question of how many other utilities and regulators will make a similar assumption, *i.e*., there is no need to build because others will do it. Here, the Council should recognize the value of having a local resource owned or controlled by the utility it regulates to protect New Orleans against rising capacity prices and reliability risks, instead of increasing reliance on entities over which the Council has no regulatory authority.

Nonetheless, at the end of the day, even assuming capacity prices that are 40% less than the Company's projections, with which the Company does not agree, the transmission-only case, which is not a viable path as discussed more fully below, is less than one percent more cost effective than the CT option under the reference and high gas cases. The transmission-only case is actually less cost effective than the CT option under the low gas case;[169] and, as Mr. Cureington testified, NYMEX projections are currently tracking closer to the low gas sensitivity.[170] The RICE alternative is within four percent of the transmission-only case in all three gas sensitivities.[171] Accordingly, for roughly the same cost, it is not reasonable to select a transmission-only option when that approach would not (i) meet the capacity need, (ii) address ENO's unique planning circumstances, or (iii) provide local reliability benefits discussed below.

The same essentially holds true under the Company's projected capacity prices. The CT's advantage over the transmission-only case is slightly greater in all three gas sensitivities, and the gap between the RICE units and the transmission-only case narrows to less than two percent.[172] Thus, again, from a total supply cost basis, it is a virtual tie, **but the transmission**

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168 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 25; Tr. (Brubaker) 12/20/17, at 173-74.

169 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 29.

170 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 67.

171 *Id.*

172 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 28.

upgrades would not provide the reliability benefits needed by New Orleans and would not meet the identified need for a local source of peaking and reserve capacity.

B. Whether ENO has demonstrated a reliability need

The evidence in this case clearly shows that the City of New Orleans faces current and persisting reliability risks since the deactivation of the Michoud units in June 2016. If left unmitigated, these risks have the potential to produce devastating and highly disruptive consequences. The Council should act as quickly as possible to protect its citizens. These risks include, among other potential consequences, the possibility of cascading outages (blackouts) and the inability to restore power as quickly as possible following a hurricane. ENO has established that the only reliable way to mitigate these concerns (*i.e.*, to have a high degree of confidence in a solution that can (1) actually be constructed; and (2) be constructed on an expedited basis) is by certifying NOPS to replace a portion of the 781 MW deactivated at ENO's Michoud Site in June 2016. As discussed more fully below, constructing NOPS will not only mitigate the risk of widespread outages, but it will also provide local generation for hurricane responses, black-start capability, reactive power, and create the ability for at least some economic growth in the City of New Orleans. The Council's Advisors and Air Products (ENO's largest industrial customer) agree that the 128 MW RICE units are needed for reliability purposes.

The recommendation to construct NOPS (and the corresponding warning against the dangerous path recommended by the Joint Intervenors) is based on the testimonies of Company witness Mr. Charles Long and Advisors witness Mr. Philip J. Movish, both of whom are electrical engineers with significant experience involving the transmission grid in the New Orleans area. Company witness Mr. Charles Long has over 25 years of experience in transmission system planning and hurricane responses in the DSG load pocket, where New

Orleans is located. Also, Council Advisor Mr. Movish has over 47 years of experience in transmission and distribution system planning, and has reviewed numerous transmission issues in the New Orleans area, including issues related to the Company's responses to various hurricanes.

On the other hand, the Joint Intervenors throw caution to the wind to advance an "anything-but-a-gas-plant" ideology, supported by witnesses with absolutely no experience in New Orleans transmission grid issues or hurricane restoration efforts. Without any supporting analysis, the Joint Intervenors argue that ENO should simply abandon its responsible plan of action to address the reliability issues facing New Orleans and play the waiting game to determine whether highly optimistic and speculative resources that they claim may be available in the future to meet ENO's reliability needs will actually materialize. Moreover, the record is clear that even if such speculative resources (*e.g.*, transmission upgrades that cannot likely be constructed, unprecedented energy efficiency levels, increased solar PV at a time when such installations in New Orleans are substantially decreasing, *etc*.) eventually materialize in the future, they cannot address the full suite of ENO's reliability needs, and are, accordingly, not the answer in this case.

Simply put, the Joint Intervenors have no independent expertise in these matters and have never been responsible for actually serving customers reliably. In other words, as stated by Company witness Mr. Charles Long in his Rebuttal Testimony, "ENO and the Joint Intervenors are not similarly situated when it comes to their expertise and responsibilities for maintaining reliability, and the Council should consider that discrepancy carefully in weighing the facts and opinions that have been offered in this proceeding."[173] The Company has established an extensive evidentiary record in this docket that supports the construction of NOPS based on reliability

[173] ENO Exhibit C. Long-3 (C. Long Rebuttal) at 12.

grounds. The plan offered by ENO provides the only realistic opportunity to mitigate the reliability concerns facing New Orleans as soon as January 2020; and the Advisors and Air Products agree that the 128 MW RICE alternative should be constructed. For these reasons, and for those discussed more fully below, the Council must take decisive action to approve NOPS.

1. NOPS will mitigate the risk of widespread outages and will help alleviate operational challenges.

a. The City of New Orleans is currently at risk for widespread outages, which NOPS will mitigate.

As the record in this docket has established, the City of New Orleans is very sensitive to reliability issues because it is located on an electrical peninsula.[174] Bordered by water to its north, east and south, there are a limited amount of existing transmission facilities that can import power into the City, all flowing from only one direction, from the West to the East.[175] This limited transmission corridor also contains poor soil conditions and wetlands, and is heavily congested with industrial, commercial, and residential structures.[176] Needless to say, the ability to import power through transmission is limited compared to other locations without this unique geography, and the region is therefore highly dependent on local generation to maintain reliable electric service.[177] This environment is typically referred to as a load pocket; and, in this case, the load pocket is called DSG.[178]

Over the course of the last 10 years, the City of New Orleans went from having three generating units within its borders to zero units, with the last two units retiring in June 2016.[179]

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174 ENO Exhibit C. Long-2 (C. Long Supplemental Direct) at 4.

175 *Id.*

176 *Id.*

177 *Id.* at 3.

178 *Id.*

179 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 10.

The transmission topology in DSG, however, which was designed to be supported by strategically placed generation in its center, and at its western and eastern (New Orleans) edges, has not materially changed.[180] Thus, following the deactivation of the Michoud Units, the leg supporting the eastern side of DSG has disappeared, meaning that, at present, and figuratively speaking, "all of the City's eggs are truly in one basket, as it is 100% dependent on transmission and remote generation," as stated by Company witness Mr. Charles Long in his Rebuttal Testimony.[181]

This unsustainable situation has resulted in a considerable amount of incremental stress on the transmission lines that serve New Orleans (*i.e.*, because the City no longer has local generation, it imports more power over those lines, which places more stress on the lines) and has led to a situation where under certain conditions, the transmission system could overload and cause cascading outages (blackouts) in large segments of the City.[182] The following Figure shows the areas that are at risk for such outages:[183]

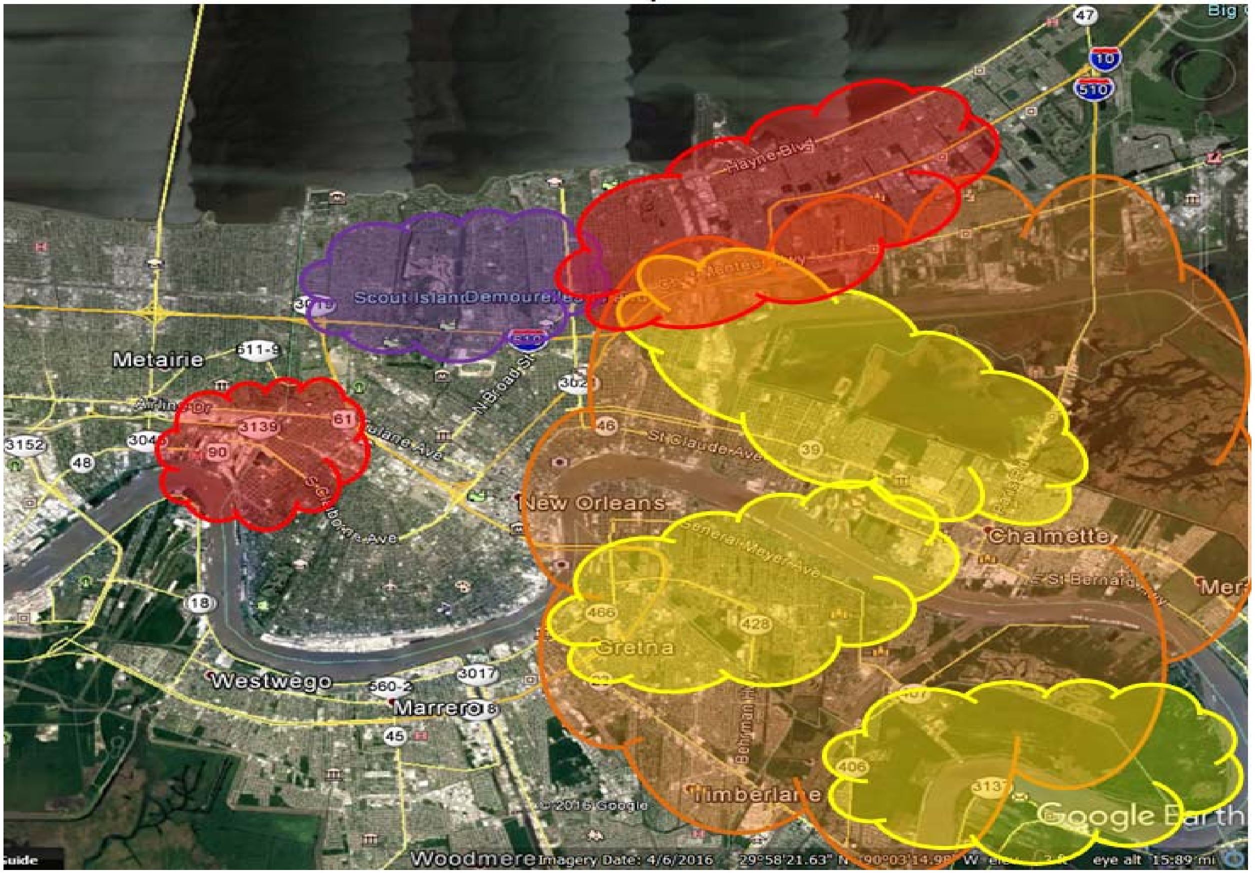
Figure 1

180 *Id.*

181 *Id.*

182 *Id.* at 3, 6 and 7.

183 ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at Exhibit CWL-6, p. 13.



As demonstrated by Figure 1 above, almost the entire City can be affected by these potential outages. It is noteworthy that no party in this case disputes this current and persisting risk.[184] In fact, MISO, in its recent MTEP 17 Report, listed the severe overloads described by the Company in this docket.[185] Even Joint Intervenors witness Mr. Peter J. Lanzalotta concedes that the deactivation of the Michoud Units resulted in the removal of 781 MW and that "[b]ecause of these generating unit retirements, this part of the Company's system requires additional resources in order to meet NERC-defined levels of reliability while serving its load as forecasted

[184] ENO Exhibit C. Long-3 (C. Long Rebuttal) at 6-7.

[185] *Id.* at 7.

for the future."[186] Accordingly, the question in this case is not whether problems exist, but rather, the best way to address them.

The Company has long stated that a new generator should be constructed to replace a portion of the 781 MW deactivated at Michoud in June 2016. Put simply, a new dispatchable local generator is the only viable option to address the reliability problems facing New Orleans. Company witness Mr. Charles Long stated the following in his Rebuttal Testimony:

> First, it makes practical sense: 781 MW of local generation was deactivated, so a portion of that generation needs to be replaced locally. This approach not only addresses the current risk of cascading in the most expeditious manner, but the Company would also not need to schedule any crippling transmission outages to construct the unit, making it likely that the units will enter into commercial operation as expected. Moreover, the Joint Intervenor Witnesses do not seriously contest that either NOPS alternative would have reliability benefits that constructing more transmission (ENO is currently 100% reliant on transmission) simply will not bring – *i.e.*, NOPS will increase operational flexibility, decrease transmission line loading the most, create reliability headroom to add new customers, aid in storm restoration (including an option for black-start capability for one of the options), increase reactive power capability, add MWs to an area dependent on local generation but that contains an aging generator fleet, and run as a Voltage and Local Reliability ("VLR") unit in the DSG load pocket. Simply put, transmission upgrades will offer none of these benefits.[187]

It is also noteworthy that even Mr. Lanzalotta admits that replacing some of the generation retired at Michoud will mitigate ENO's reliability concerns, agreeing that "incremental generation in DSG to replace the retired Michoud generation would mitigate ENO's reliability concerns,"[188] including "[t]he NERC reliability concerns that we're dealing with in this case."[189]

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186 Joint Intervenors Exhibit Lanzalotta-1 (Lanzalotta Direct) at 5.

187 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 8.

188 Tr. (Lanzalotta) 12/21/17, at 49.

189 *Id.*

Moreover, at the September 13, 2017 New Orleans City Council Utility, Cable, Telecommunications and Technology Committee meeting, a representative of MISO, in his oral comments, detailed the ongoing operational challenges of operating the grid in the DSG load pocket, emphasized the importance of having local generation in the City of New Orleans, and stated that Michoud is a good location for that generation.[190] The MISO representative stated that MISO's system operators believe that local generation is needed to operate the grid in a manner that avoids unreasonable reliability risks and ensures that the grid is well equipped to deal with operational challenges and unforeseeable circumstances.[191]

It should also be noted that while the concerns at issue would normally trigger NERC violations, as alluded to by Mr. Lanzalotta, the Company is not currently violating NERC because it has a corrective action plan to respond to the early unit deactivations, which were unforeseen events.[192] As stated by Mr. Charles Long, however, the Company is required to "make good faith efforts to implement" its corrective action plan; and new generation is the only mitigation measure that the Company is confident that it can implement.[193] As discussed more fully below, the Company has very little confidence that it could implement transmission upgrades in a timely manner, and this lack of confidence applies equally to the other speculative resources that the Joint Intervenors would urge this Council to consider.[194] At the December 2017 Hearing, Mr. Charles Long emphasized that he "would not want to go into a [NERC] audit with a plan [that he] didn't think [that he] could implement;"[195] and stated that in order to meet its

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190 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 9.

191 *Id.*

192 Tr. (C. Long) 12/15/17, at 129-30.

193 *Id.* at 191.

194 *Id.*

195 *Id.*

obligations under NERC, the mitigation measure should be one that "reasonable people in [his] profession would agree is something that would alleviate the issues and be attainable."[196] The construction of NOPS is the only option that meets these criteria.

In contrast, the Joint Intervenors would seek to prevent and delay the Company from undertaking the only project that it can reasonably rely upon to mitigate its NERC concerns in an accelerated manner, indicating that they simply have no sense of urgency regarding the serious reliability issues facing the City of New Orleans. The Joint Intervenors believe, without any analysis, that the likelihood of widespread outages is small and that load shedding can be used to mitigate any concerns during the lengthy period needed to pursue their wait-and-see approach. Such inaction is unacceptable because, among other reasons, the likelihood of the widespread outages is not small; and if they occur, the resulting outages would be substantial and would implicate almost the entire City of New Orleans.

Even Joint Intervenors witness Mr. Lanzalotta, who referred to a P6 double contingency (the circumstance that would produce widespread outages) as an "extreme contingency" in his Direct Testimony,[197] admitted at the hearing that a double contingency is not defined as "extreme" by the NERC standards and that the mitigation of a double contingency is not voluntary.[198] In other words, Mr. Lanzalotta admitted that the Company is required to have a mitigation measure in place to address P6 double contingencies, as well as single contingencies (P 2.3) under the NERC standards.[199] Thus, the Company could not simply choose to "ride-through" any of these risks, as it is required by law to mitigate the concern.

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196 *Id.* (emphasis added).

197 Joint Intervenors Exhibit Lanzalotta-1 (Lanzalotta Direct) at 6.

198 Tr. (Lanzalotta) 12/21/17, at 41-42,

199 *Id.* at 42.

Next, the suggestion to use load shedding to mitigate these serious reliability concerns is also alarming. Plainly stated, load shedding means "shutting off load that would otherwise be served,"[200] and as the Joint Intervenors' own expert Mr. Lanzalotta agreed, load shedding means that "first people have service and then under a load shed condition, they would not have service."[201] Mr. Lanzalotta also admitted that "load shedding could affect homes, businesses, churches, and hospitals"[202] and that a grid prone to load shedding could be less likely to attract new loads and businesses.[203] While the Company will use load shedding if at all possible to mitigate widespread outages until NOPS is constructed, the concept of load shedding essentially amounts to swapping huge high-impact-outages for large high-impact-outages, which is unacceptable as a long-term strategy for providing reliable service.

Moreover, as mentioned above, the Company is required by its federal regulator, NERC, to meet required performance standards for **all** planning events in the standard, whether they stem from a single or double contingency. Thus, any suggestion that the Company can "ride-out" the risks associated with the outages that result from any contingency studied by the Company is misplaced. Under NERC, as stated by Company witness Mr. Charles Long, the Company "ha[s] to mitigate all the reliability issues, not just the most pressing ones. All of them."[205] This point was also admitted by the Joint Intervenors' expert, Mr. Lanzalotta, who testified at the December 2017 Hearing that the mitigation of both single and double

200 *Id.* at 40.

201 *Id.* at 41.

202 *Id.* at 40.

203 *Id.* at 41.

205 Tr. (C. Long) 12/15/17, at 220.

contingencies is not voluntary, and that the Company is required to take action to mitigate these risks under NERC requirements.[206]

b. The minimum amount of generation needed to address reliability concerns is 128 MW.

The 128 MW RICE units would mitigate most reliability issues, but transmission projects may still be needed in 2027 to address minor overloads according to the Company's analysis. Under that scenario, having a generator in place by January 2020 would allow the Company to feel comfortable with waiting a few years to make a decision about the 2027 transmission projects, but to be clear, 128 MW is the minimum amount of generation that should be added; and adding less than that minimum amount is not an acceptable outcome from a reliability perspective. Company witness Mr. Charles Long summarized the need for at least 128 MW RICE Units at the Michoud Site as follows:

> There's one upgrade still in 2027 and we've compromised on that point. And, you know, again, as a transmission guy, I would rather see a bigger unit to get rid of all of [the reliability issues]. But given that it's in 2027—we would not want to go lower than 128 because that really isn't enough. It's enough to make us feel okay about waiting a couple of years to see what happens, but I would submit that 128 is the minimum. I would be uncomfortable with anything smaller.[207]

The Company studied a generic unit sized at 110 MW as a proxy in its reliability studies,[208] which also resulted in the need for a transmission project in 2027; and while there is still a possibility that the Company may need to either add an additional RICE unit (for a total of 8) or construct transmission by 2027 if the 128 MW unit is constructed, the likelihood of needing additional investment decreases as the output of the unit increases. This principle is illustrated

206 Tr. (Lanzalotta) 12/21/17, at 41-42.

207 Tr. (C. Long) 12/15/17, at 220.

208 *Id.*

nicely by the fact that a generic unit studied at 170 MW completely resolves all reliability issues without the need for any transmission projects.[209] Thus, as Company witness Mr. Charles Long stated at the hearing, "we need more than 110." And the more generation that is added at the site, the less likely additional investment will be needed in the future to maintain reliability.[210]

Importantly, as stated by Mr. Charles Long, the 128 MW of output unloads all of the transmission lines in DSG "[s]o if we got to 2027 and we needed to do this transmission upgrade, we're much more likely to be able to get the outage to do it."[211] This means that once a unit is constructed, the Company can depend on that unit to provide counter-flow to the system, thereby decreasing transmission line loading to the point where if an outage is taken to construct any necessary future upgrades, other lines in the system will not overload causing widespread outages. Conversely, without a new unit at the Michoud Site, the necessary counter-flow would not exist, taking away the ability to take a transmission outage to construct upgrades, which the Joint Intervenors completely ignore when advancing the construction of five transmission upgrades, or advocating reliance on an unrealistic scenario involving 200MW of solar at the Michoud Site combined with the 2% DSM goal, as discussed more fully below.

Also, it is undisputed that there will be times when the Company will need to take one or more of the RICE units offline for planned or forced outages, and the more generation remaining to rely on for reliability the better.[212] As stated by Mr. Charles Long, "it's borderline at 128 and

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209 ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 13; Tr. (C. Long) 12/15/17, at 233.

210 Tr. (C. Long) 12/15/17, at 220.

211 *Id.* at 233-34.

212 *Id.* at 225.

then we would have some periods to maintain the units."[213] Accordingly, the full 128 MW, at a minimum, is needed at the Michoud Site to mitigate reliability concerns.

c. Operational grid issues have already occurred following recent deactivations.

It is also undisputed that since the retirement of the Michoud Units, the Company has faced serious operational challenges related to the transmission system.[214] The large increase in flows of power on the transmission system has often led to stressed operational conditions, resulting in the rejection of outage requests needed for the maintenance of existing transmission lines.[215] In fact, as detailed by Company witness Mr. Charles Long in his Supplemental and Amending Direct Testimony, in the first half of 2017 alone, outages involving a 115 kV transmission segment, a 230/115 kV auto-transformer, five 230 kV transmission lines, and two 500 kV transmission lines were denied because of reliability constraints that could not be mitigated without risking electric service to the Company's customers.[216]

Yet another concrete example of severe operational constraints resulting from a scarcity of generation in DSG is the occurrence of load-at-risk alerts and maximum generation events.[217] As Company witness Mr. Charles Long has explained, local generation shortfalls that occur operationally are monitored using the Entergy Load Risk Alert Levels ("ELRAL") protocol of four alert levels.[218] In the first half of 2017 alone, operational generation shortages have resulted in, for example, six ELRAL issuances for DSG and six ELRAL issuances for Amite South (two

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213 *Id.* at 225.

214 ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 6-7.

215 *Id.*

216 *Id.*

217 *Id.* at 7-8.

218 *Id.* at 6-7.

of these ELRAL declarations being for both Amite South and DSG).[219] Mr. Charles Long stated at the hearing that he has monitored the progression of these operational issues and that they have "certainly increased" after the Michoud units retired.[220] Having a local generator in New Orleans would reduce the stress on the heavily loaded transmission lines located in the area and would accordingly mitigate these serious operational issues.[221] Even Joint Intervenors witness Mr. Lanzalotta agreed with this point at the December 2017 Hearing, stating the following:

> **MR. GUILLOT:** You agree that a local generator in New Orleans such as New Orleans Power Station will provide counterflow to the transmission system feeding DSG [and] New Orleans such that these operational issues will become less challenging; right?
>
> **MR. LANZALOTTA:** That's correct. These issues, as I recall, first became an issue when the Michoud units were retired, Michoud 2 and 3. Before that, I don't believe they were nearly as much of an issue.[222]

Furthermore, from an operational perspective, it is also extremely concerning that MISO has two less VLR units available for use in a critical location following the recent deactivations. As discussed by Company witness Mr. Charles Long, MISO operates the transmission system in the southern load pockets, including DSG, in a manner that <u>exceeds</u> the NERC operational reliability standard by implementing what is called "[VLR] operating guides."[223] Moreover, at the hearing, it was pointed out that Joint Intervenors witness Mr. Lanzalotta admitted in his deposition, that it "is reasonable for MISO to require a more stringent operating standard" than NERC "under these particular conditions" because, as he stated, "it's a load pocket."[224] He also admitted that he has

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[219] *Id.*

[220] Tr. (C. Long) 12/15/17, at 189.

[221] ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 8.

[222] Tr. (Lanzalotta) 12/21/17, at 43.

[223] ENO Exhibit C. Long-3 (C. Long Rebuttal) at 40.

[224] Tr. (Lanzalotta) 12/21/17, at 48-49.

"no reason to doubt that"[225] if a NOPS unit is built, it will also be utilized as a VLR unit by MISO, meaning that it is undisputed that a new unit will run for reliability purposes in the region and mitigate the current operational issues discussed above by significantly de-stressing the transmission grid in the region.

d. New generation is needed at a specific location: ENO's Michoud Site.

Incremental local generation is needed in a specific place: where 781 MW of generation retired in June 2016—the Michoud Site. The evidence in this case is clear that the Michoud Site has a strong connection to the transmission system, and locating generation at Michoud will address the current and persisting risk of widespread outages as well as provide a host of other benefits described more fully below. As stated by Company witness Mr. Charles Long in his Rebuttal Testimony, and as mentioned above, "[t]he DSG load pocket was designed to be supported by strategically placed generation in its center, and at its western and eastern edges. Following the retirement of the Michoud units, however, the leg supporting the eastern side of DSG has disappeared . . . ."[226]

Advisor witness Mr. Movish agrees with this assessment, indicating in his Direct Testimony that "ENO's system is located at the extreme eastern end of the DSG load pocket" and that "[c]onsidering ENO's transmission system topology, the proposed location of local generation at ENO's former Michoud site would be beneficial from a transmission reliability perspective . . . ."[227] Even MISO has expressed a similar sentiment, stating in oral comments at the September 13, 2017 New Orleans City Council Utility, Cable, Telecommunications and

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225 *Id.* at 58.

226 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 10.

227 Advisors Exhibit Movish-1 (Movish Direct) at 24.

Technology Committee meeting that it is important to have local generation in the City of New Orleans, and that Michoud is a good location for that generation.[228]

For his part, Joint Intervenors witness Mr. Lanzalotta also agreed that Michoud is a good location for siting new generation. When asked whether he agreed that "there are benefits . . . to putting generation in the same location that old generation, the retirement of which is causing NERC violations, has been taken out of service," Mr. Lanzalotta agreed that "there [are] benefits," but also stated that there could be what he called "disbenefits," if the site is prone to flooding.[229] Tellingly, however, Mr. Lanzalotta also admitted that he (1) has not done any analysis regarding the risk level of flooding at Michoud; (2) was not aware that the Mississippi River Gulf Outlet ("MRGO") had greatly contributed to the flooding in New Orleans after Hurricane Katrina and that the United States Army Corps of Engineers ("USACE") has closed the MRGO; (3) was not aware that since Hurricane Katrina, the USACE had constructed the world's largest surge barrier in New Orleans East, the IHNC Lake Borgne surge barrier; and (4) was not aware of the substantial improvements to the flood walls in New Orleans East.[230]

In fact, after learning about these substantial developments, and the fact that the new unit will be elevated to a much higher level than the old Michoud units were at the time of Hurricane Katrina, Mr. Lanzalotta was forced to admit that the flood risk at the Micoud location is "at least . . . not as risky as it was before Hurricane Katrina."[231] When asked whether businesses in New Orleans and New Orleans East that returned after Hurricane Katrina made a mistake considering the flooding that occurred during that hurricane, Mr. Lanzalotta responded "[n]o."[232] The

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228 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 13.

229 Tr. (Lanzalotta) 12/21/17, at 43.

230 *Id.* at 68-70.

231 *Id.* at 69-70.

232 *Id.* at 70-71.

Company wholeheartedly concurs; and following the retirement of the Michoud units, the Company is obligated to support these businesses and residents by ensuring the reliability of the electric grid in New Orleans East through constructing incremental local generation.

2. Crucially, NOPS will also provide much needed hurricane restoration support.

Presently, the City of New Orleans, for the first time in modern history, does not have a local generator within its borders to respond to hurricanes. As Company witness Mr. Charles Long has stated, "it should be obvious that having local generation in a storm prone area is imperative to assist restoration crews in returning service to customers as quickly as possible, which the Company is obligated to do."[233] No party has seriously contested this point.

Under a scenario with no local generation, damage to the transmission system would render restoration efforts fruitless until the transmission system is able to transport power from remote resources to the City's loads. On the other hand, a local resource would provide an alternative source of power to the distribution system over shorter distances of transmission. Thus, as stated by Company witness Mr. Charles Long in his Rebuttal Testimony, "a local resource will restore power following a storm faster and give a system operator the flexibility to restore loads quicker than if the City were 100% dependent on transmission."[234] Mr. Long also used the following analogy to describe the importance of local generation in his Rebuttal Testimony: "Depending solely on long distance transmission for restoration would be akin to relying upon the fire department in the City of Kenner to fight fires in New Orleans East, rather than having local fire stations to provide this timely and essential service. It is obvious that

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[233] ENO Exhibit C. Long-3 (C. Long Rebuttal) at 19.

[234] *Id.* at 25.

relying upon the Kenner Fire department will expose New Orleans East residents to significant risks considering the distance and traffic conditions at issue."[235]

The Advisors have also acknowledged that there are significant benefits that local generation can bring to New Orleans, but that constructing more transmission cannot, stating in Mr. Movish's Direct Testimony that:

> [T]he RICE Alternative also would provide other significant benefits to New Orleans, including operational flexibility, dynamic system support for voltage regulation, on-site black start capacity to support restoration of service after a major outage or storm event, and the ability to provide a source of power to ENO's critical loads in the event of an outage. Further, the RICE Alternative, subject to further study, could potentially provide a source of power for the Sewerage & Water Board's ("S&WB") Carrolton facility in the event that S&WB's generation was impaired or inoperable.[236]

Air Products witness Mr. Maurice Brubaker also recognized the benefits of having local generation in a storm situation. When asked whether he believes that the installation of the RICE units would have storm restoration benefits, Mr. Brubaker responded that "by having it local and having it with black start capability" the RICE units would indeed "facilitate the restoration of the system following a hurricane or other adverse weather event."[237]

Even Joint Intervenors witness Mr. Lanzalotta was forced to concede that, "under storm conditions," there are advantages to locating generation in proximity to the load it serves.[238] Mr. Lanzalotta further admitted that one such benefit is that there are "fewer wires between a unit and a load that can be taken down by the storm."[239] Accordingly, given this critical admission, it

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235 *Id.* at 25.

236 Advisors Exhibit Movish-1 (Movish Direct) at 4-5.

237 Tr. (Brubaker) 12/20/17, at 179.

238 Tr. (Lanzalotta) 12/21/17, at 38-39.

239 *Id.* at 39.

can hardly be argued that having local generation is not advantageous in a storm situation. Presently, New Orleans has no such generation, and ENO's customers are accordingly exposed to longer restoration times following a major hurricane due to the lack of local generation.

Another obvious benefit of local generation is that it can provide service to customers in the event that the City or the region is either completely islanded, meaning that all or a significant portion of the transmission lines that import power into the region are forced out of service during a storm. To be clear, however, this is not a hypothetical situation; the system has experienced this condition during a previous storm. In Hurricane Gustav, for example, 14 out of 14 critical transmission tie-lines were forced out of service, disconnecting a region that included the City of New Orleans from the remainder of the U.S. electric grid.[240] During that time, New Orleans was totally dependent on electric service generated locally within the island for any load that was served.[241] In other words, during Hurricane Gustav, transmission lines external to the "island" could not have powered a single additional home, business, hospital, or pumping station.[242]

Joint Intervenors witness Mr. Lanzalotta, in his Direct Testimony, argued that local generation did not prevent widespread outage during Hurricane Gustav because he claims that 80% of the Company's customers were interrupted by the storm. Even accepting this as true, however, Company witness Mr. Charles Long pointed out in his Rebuttal Testimony that "Mr. Lanzalotta's example actually further illustrates the Company's point, which is that without local generation, the 20% of customers that were able to continue accept electric service . . . would

240 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 26.

241 *Id.*

242 *Id.*

have been in the dark."[243] At the December 2017 Hearing, Mr. Lanzalotta was again forced to admit that the 20% of customers who maintained service "were kept in service by the presence of local generation"[245] and that this 20% could have included "hospitals, police stations, and other critical load."[246]

Moreover, in response to Mr. Lanzalotta's contention in his Direct Testimony that the Michoud units did not run during Gustav, Company witness Mr. Charles Long, who participated in transmission restoration efforts during Gustav and led the activities to reconnect the islanded load to the eastern interconnection, stated that while the Michoud units were taken offline during the actual storm event, Michoud Unit 2 was brought back online on the second day after the storm hit (which was the first day of restoration efforts), when only 3 of the 14 tie-lines had been restored to service.[247] At the Hearing, Mr. Lanzalotta conceded that on Day 2 of the restoration, with only 3 of the 14 tie-lines restored, "transmission restoration was only beginning" and "there's a pretty good chance that the area was dependent on local generation to serve load."[248] In fact, it should also be noted that more than five days after the storm, with only 6 of the 14 transmission tie-lines restored, Mr. Lanzalotta also admitted that transmission restoration efforts were still not yet complete,[249] which highlights the lengthy amount of time that can be needed to repair transmission lines following a storm and the importance of having local generation in New Orleans to avoid dependence on exposed transmission lines.

243 *Id.* at 27 (citation omitted).

245 Tr. (Lanzalotta) 12/21/17, at 66.

246 *Id.* at 66-67.

247 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 28.

248 Tr. (Lanzalotta) 12/21/17, at 67.

249 *Id.* at 68.

Joint Intervenors witness Mr. Lanzalotta also agreed at the December 2017 Hearing that it is "possible for a storm to separate New Orleans from the rest of DSG" and that if such a scenario were to occur, "New Orleans would be dependent on local generation" within its borders to maintain service to its customers.[250] Company witness Mr. Charles Long discussed this same risk in his Rebuttal Testimony, stating that it is possible for New Orleans to become its own electrical island, and, in that situation, given the lack of generation in the New Orleans area, all electric loads would be lost.[251] Mr. Long also stated that this scenario actually involves the outages of fewer transmission lines than the fourteen lines implicated in Hurricane Gustav's island.[252]

In such a situation, blackstart capability could be an important and vital benefit that would greatly enhance the Company's ability to restore electric service should a complete loss of service on the electric system occur. And as described by Company witness Mr. Jonathan E. Long, the RICE units will be equipped with blackstart capability.[253] The Company's current blackstart plan involves energizing a path from nearly 40 or 50 miles away.[254] Thus, all parties, even Joint Intervenors witness Mr. Lanzalotta agreed that "there are benefits to having black start capability within the City of New Orleans."[255]

Furthermore, it is also undisputed that such blackstart capability could also prove vital if the grid goes totally dark, and the S&WB pumps need to be energized. Under that situation, preliminary studies have indicated that NOPS could be used to energize a path from the Michoud

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250 *Id.* at 68.

251 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 28-29.

252 *Id.* at 28-29.

253 ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 13.

254 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 32; Tr. (C. Long) 12/15/17, at 215.

255 Tr. (Lanzalotta) 12/21/17, at 68.

substation to ENO's Joliet substation in order to supply start-up power to the S&WB's facility in in case the pumps need to be started.[256] ENO's preliminary analysis, which consisted of a steady-state reliability analysis and a dynamic time-domain stability analysis, indicates no barriers to starting-up the S&WB's facility using the NOPS RICE Units.[257] Should the Council approve the NOPS resource, the Company would then need to conduct a more detailed analysis in order to ensure that no additional steps are needed and would then need to work with the S&WB to implement such a plan.[258] In response, and without any analysis or supporting expert testimony, the Joint Intervenors argue that the use of ELL's Ninemile facility, which is located across the open water of the Mississippi River, can be used to blackstart the S&WB's facility. This argument is misplaced, however, given that ELL's Ninemile facility does not have blackstart capability and the closest blackstart facility is "orders of magnitude further" than the Michoud Site, 40 or 50 miles up the river.[259]

3. *Local generation will provide a host of other reliability-related benefits that merely focusing on NERC compliance will not produce, such as increasing operational flexibility, reliability margins, reactive power, economic growth, hurricane preparedness, and substantially reducing line loading.*

As discussed more fully below, the transmission upgrades advanced by the Joint Intervenors are not constructible in a timely manner; but even if they were, their construction would achieve NERC compliance to the exclusion of the other substantial benefits of local generation that are important for maintaining grid stability. In other words, adding local generation addresses multiple issues with one facility, while adding transmission *may* address one issue *if* the upgrades can be constructed, which as discussed more fully below, is a big

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256 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 44-45.

257 *Id.*

258 *Id.*

259 Tr. (C. Long) 12/15/17, at 215.

assumption. At the hearing, Joint Intervenors witness Mr. Lanzalotta admitted that "NERC set[s] the floor on required levels of reliability, not an upper limit;"[260] and his Direct Testimony reveals that he agrees that there are times when that floor can reasonably be exceeded to account for local reliability considerations.[261]

For example, as mentioned above, Mr. Lanzalotta agreed in his deposition that it is reasonable for MISO to operate the DSG region to a reliability standard that is more stringent than NERC requires because, in his words, "it's a load pocket."[262] This concession implies that it is sometimes reasonable to go beyond the plain vanilla NERC requirements to address local considerations. In yet another example, Mr. Lanzalotta indicated in his Direct Testimony that ENO should consider addressing storm preparedness by undergrounding its transmission lines, which is also not required by the NERC standards.[263] To be clear, undergrounding ENO's transmission lines would be costly, difficult, and importantly, would not increase ENO's storm preparedness due to the heavy reliance on overhead transmission outside ENO's service territory;[264] but Mr. Lanzalotta's suggestion, coupled with his admission that it is reasonable to operate a load pocket to a more stringent standard than NERC requires, clearly illustrates the point, which is that the Joint Intervenors seemingly support going beyond the NERC requirements to mitigate practical, real-world local concerns – as long the mitigation measure does not involve the construction of a gas-fired generator.

There are also several other additional benefits related to local generation that are not addressed by NERC, but that are vital to maintaining a reliable electric grid. For example, as

260 Tr. (Lanzalotta) 12/21/17, at 44.

261 Joint Intervenors Exhibit Lanzalotta-1 (Lanzalotta Direct) at 9-10.

262 Tr. (Lanzalotta) 12/21/17, at 48-49.

263 Joint Intervenors Exhibit Lanzalotta-1 (Lanzalotta Direct) at 9-10.

264 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 30-31.

discussed by Company witness Mr. Charles Long, increasing operational flexibility by easing the loading on the grid is an extremely important benefit that will give grid operators the ability to respond to unexpected conditions, grant approvals to conduct maintenance outages, and issue fewer "load at risk alerts" in the DSG area.[265] Similarly, having the headroom to undertake necessary maintenance on transmission lines and add new customers without exposing the area to reliability risks are also vitally important benefits in an area like New Orleans, which is primed for economic growth.[266] Conversely, failing to consider these important needs, as advocated by the Joint Intervenors, risks creating an impediment/obstacle to such growth.[267]

In his Rebuttal Testimony, Company witness Mr. Charles Long presented the following table, which lists the impact on the degree to which transmission line loading will be reduced as a result of the following three scenarios: (a) the construction of the transmission upgrades listed in Table 1 of Mr. Long's Supplemental and Amending Direct Testimony; (b) the 128 MW RICE resources; and (c) the 226 MW CT.[268] As can be expected, the CT produces the biggest reduction in flows on the transmission system; hence, the CT can be expected to increase operational flexibility and reduce stress on the system the most. Conversely, the transmission-only option produces the smallest magnitude of transmission line flow reductions, and therefore, is expected to result in a transmission grid with the least amount of operational flexibility.

Table 1[269]

Number of Transmission Lines with Significant (more than 10%) Flow Reductions in 2022		
Transmission Only	128 MW RICE	226 MW CT

265 *Id.* at 19-22.

266 *Id.* at 19.

267 *Id.*

268 *Id.* at 21-22.

269 *Id.* at 22.

4	24	33

From the perspective of enabling customer growth, the transmission system must have some headroom/reliability margins in order to serve new load without being vulnerable to reliability issues.[270] For example, as stated by Company witness Mr. Charles Long in his Rebuttal Testimony, the same Joint Intervenors that are opposing the construction of the NOPS alternatives are also likely to favor the increased use of electric vehicles.[271] While the Company does not necessarily endorse his statements, it should be noted that Tesla's CEO, Elon Musk, has predicted that electric demand will substantially increase by 200%, as cars and heating transition to electricity as a source of fuel, which will increase dependency on traditional utility resources by a factor of two.[272]

In another more immediate example, Mr. Long has stated that the Company is in discussions with a potential customer that presently has over 50 MW of load, which has not been included in ENO's load forecast.[273] While this prospective customer is a little more certain to interconnect because the load currently exists on the system (but is currently served by self-generation), Mr. Long has stated that the Company is also in constant discussions with potential new developmental customers, none of whom will locate their businesses in New Orleans without assurances that electric service will be reliable.[274] The point here is this: it is best to have a system that can handle changes, like the addition of a new customer, without putting customers at risk; and it is undisputed that the transmission upgrades at issue, while ensuring NERC

[270] *Id.* at 23.

[271] *Id.*

[272] *Id.*

[273] *Id.*

[274] *Id.*

compliance (if and when they are constructed), will not create reliability margins on the transmission system sufficient to handle any new growth.[275]

Yet another benefit of local generation is that it will also add capacity to an area (the DSG load pocket) that is highly dependent on local generation, but that has an aging generation fleet. It is also undisputed that in 2018, ENO will serve 34% of the load in DSG, but will only own a *de minimis* amount of the generation in DSG. At the hearing, Mr. Lanzalotta admitted that he has no basis to dispute that Michoud Units 2 and 3 represented approximately 29% of the generation in the load pocket before their retirements.[276] Mr. Lanzalotta also agreed that the DSG load pocket is dependent on local generation to ensure reliability.[277] Simply put, ENO must ensure its own reliability by constructing generation to ensure the orderly replacement of the aging and retiring units in DSG, like Michoud Units 2 and 3. The Company, following the termination of the Entergy System Agreement, must move toward becoming more self-reliant and cannot simply rely on other utilities to construct generation for the benefit of New Orleans. ENO and the Council must act responsibly, because they are responsible for serving customers reliably. And this practical, real-world problem is yet another example of an issue that will be addressed by adding local generation, but that merely focusing on meeting the NERC standards would ignore.

4. The Council should not gamble grid reliability on risky transmission upgrades.

The Joint Intervenors uniformly argue that instead of building local generation to replace a portion of the deactivated Michoud units, the Company should instead upgrade five existing transmission lines. The Company has consistently stated, however, that there are serious

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275 *Id.*

276 Tr. (Lanzalotta) 12/21/17, at 58.

277 *Id.* at 38.

constructability problems associated with the transmission upgrades; and that constructing the upgrades sounds a lot easier than it will prove to be in reality. Company witness Mr. Charles Long has stated that the upgrades would "be extraordinarily difficult" to construct because of, among other things, challenging outage requirements; and while each and every line is out for upgrade, "the risk of cascading outages and/or the impact of an unplanned outage will increase dramatically."[278] The City faces a current and persisting reliability challenge, and the Council must have a sense of urgency with respect to mitigating these issues.

To be clear, the inability to obtain necessary outages due to the current real-world stressed operating conditions in DSG is an insurmountable obstacle to a strategy that involves the construction of transmission upgrades. As discussed above, since the retirement of the Michoud units, operating conditions in the DSG load pocket have been extremely difficult, with nine transmission outages being denied in the first half of 2017 alone.[279]

Company witness Mr. Charles Long has stated that the construction of the five upgrades could take eight to ten years, given that the construction of <u>even one line</u> could take several years when considering outage requirements. For any particular upgrade, Mr. Long stated that in the first year of the project, the Company would "take it out for a month in the fall and then a month in the spring,"[280] then this process would be repeated for several years until the project is completed. Thus, as Mr. Long stated, "[e]ven though you need 12 months [of outages for one upgrade], it can take many years to get those 12 months of outages because you can only do it at the lowest load times."[281] Considering that this process would need to be repeated for five lines

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278 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 4.

279 ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 5-6.

280 Tr. (C. Long) 12/15/17, at 197.

281 *Id.* at 197-98.

which will be constructed one at a time, Mr. Long estimated eight to ten years before the Company could finish all the transmission upgrades.[282] For his part, Joint Intervenors witness Mr. Lanzalotta agreed that "[i]f the company could only construct upgrades one at a time because of outage requirements . . . this could add significant time to the project as a whole."[283]

Advisor witness Mr. Movish also agrees with the Company on this point, explicitly stating in his Direct Testimony that the "Transmission Alternative, either with or without the inclusion of the 2 percent DSM and solar photovoltaic PV capacity, presents significant reliability risk to New Orleans customers" and that he would expect ENO to face "difficulties in taking its transmission lines out of service for the accomplishment of the needed upgrades . . . especially considering the duration of outages that would be required to replace transmission structures in support of re-conductoring, and the time required to accomplish re-conductoring work."[284]

In his Rebuttal Testimony, Company witness Mr. Charles Long stated that "[i]f the Company cannot receive the necessary outages to construct the upgrades, which is likely to be the case in the absence of a local resource that can provide counter-flow on the transmission network, the Company would need to build the upgrades along new transmission paths, adding significant costs and time to the projects at issue."[285] Even Joint Intervenors witness Mr. Lanzalotta agreed at the hearing that if new paths are needed, then additional "rights of way and potential condemnation proceedings could be in order," which "could impact homes, churches, schools, and businesses."[286] Mr. Lanzalotta also admitted that based on his experience, this

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282 *Id.* at 207-08.

283 Tr. (Lanzalotta) 12/21/17, at 57.

284 Advisors Exhibit Movish-1 (Movish Direct) at 4, 27.

285 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 11.

286 Tr. (Lanzalotta) 12/21/17, at 51-52.

process could add “significant time to the project”[287] and that “community members usually react pretty negatively”[288] to that process.

It is also clear that the Joint Intervenors have not, and cannot, offer any analysis that supports the feasibility of constructing any of the upgrades in an accelerated manner, and that their dangerous recommendation will leave customers unnecessarily and unreasonably exposed to reliability risks for a longer period than is necessary. In his Rebuttal Testimony, Company witness Mr. Charles Long stated clearly “that outage scheduling depends on real-world system conditions, which the Company cannot reasonably predict due to the many unknown variables involved.”[289] At the December 2017 Hearing, Mr. Long elaborated on this point, stating the following:

> [T]o plan the work would take many months, nine months, a year for each of the upgrades to go out and make a plan . . . .Then when you got two or three or four years down the road, when you were ready to take the outage, only then would you find out if that plan is viable. You can’t predict years in advance whether you’re going to be able to take outages on the facilities and when you can get them.[290]

Even Joint Intervenors witness Mr. Lanzalotta conceded to the difficulty in trying to predict when an outage can be taken, agreeing that the “ability to take an outage on a transmission line in the future for maintenance or construction depends on system operating conditions in the future;” and that “factors such as generation availability, transmission line availability, storms, [and] accidents” make it difficult to predict real world conditions in the future.[291] Further, Mr. Lanzalotta admitted that real-world operating conditions are “seldom perfect” and that “in

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287 *Id.* at 57.

288 *Id.* at 52.

289 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 13-14.

290 Tr. (C. Long) 12/15/17, at 197.

291 Tr. (Lanzalotta) 12/21/17, at 55-56.

general, there's almost always some kind of problem."[292] These statements evidence the fact that no party can reliably assure the Council that the transmission upgrades in question can be constructed on an expedited basis because such an analysis is nearly impossible and would be extremely inaccurate given uncertain future operating conditions.

On the other hand, it is uncontested that NOPS can be constructed without needing to take any extended transmission outages and the Council can have a high degree of confidence that, by deploying either NOPS alternative, the current threat of cascading outages will be mitigated as quickly as possible. In fact, Mr. Lanzalotta acknowledged at the hearing that ENO owns the land located at the Michoud Site, and conceded that "any minor outages necessary to interconnect the unit would be incidental compared to the rebuilding of one of these five transmission lines at issue in this case."[293]

It is also significant to consider that if these upgrades are constructed during long periods of time, ENO would then be forced to operate at a significantly higher risk of cascading outages during the construction outages. Ultimately, as Company witness Mr. Charles Long stated at the hearing, "[w]ith enough time and enough money and accepting enough risk, anything is potentially possible," but there are "serious doubts that [the Company] could implement all of those transmission upgrades without having a big event."[294]

Mr. Long stressed that the upgrades would be "very difficult, very time consuming, [and] would take much longer and have more risk than just building a generator on the site that [the Company] already own[s]."[295] Moreover, even if constructed, the upgrades would not hold a

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292 *Id.* at 55.

293 *Id.* at 49-50.

294 Tr. (C. Long) 12/15/17, at 171.

295 *Id.* at 172.

candle to the additional reliability benefits of constructing local generation (discussed above); and would leave customers exposed to many of the operational reliability issues currently faced today because the upgrades would not significantly unload the transmission system, as discussed above.[296] Simply put, as Company witness Mr. Charles Long indicated, "the transmission upgrades are not an adequate solution to the suite of current reliability issues facing New Orleans based on [his] experience as a transmission planner."[297]

It is also important to note that transmission does not equal generation. Even Joint Intervenors witness Mr. Lanzalotta agreed that "transmission moves power around, it does not generate power."[298] Put differently, in many respects, transmission is like an extension cord, it simply moves power around from one place to another, and a power source is always needed at the end of the extension cord. At equilibrium, however, which is projected to occur in the 2022/23 timeframe, it is undisputed that there could be no excess capacity on the market to import. Under that circumstance, even Mr. Lanzalotta agreed that "[i]f there's less capacity on the system and, therefore, less ability to import that capacity inside the load pocket . . . dependence on local generation for reliability would increase."[299] Put differently, even if the transmission upgrades at issue in this case are constructed, they cannot address reliability if there is no excess capacity to import at equilibrium. Only NOPS can address that issue. In this case, as discussed more fully above, the construction of NOPS is truly a "no regrets" solution because it will add capacity to ENO's portfolio as equilibrium approaches, mitigating the need to purchase expensive capacity from the market; and it will also place more capacity in proximity to ENO's

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[296] ENO Exhibit C. Long-3 (C. Long Rebuttal) at 21.

[297] *Id.* at 4-5.

[298] Tr. (Lanzalotta) 12/21/17, at 52.

[299] *Id.* at 55.

load, the City of New Orleans, helping to maintain reliability in the event that there is less capacity available on the system to import.

5. The Council cannot rely on speculative resources to resolve reliability issues or facilitate outage scheduling.

The Joint Intervenors in this case, without any supporting analysis, collectively advocate that the Council should gamble the reliability of the transmission grid in New Orleans on speculative resources such as increased solar, increased load reductions over time (energy efficiency), increased demand response, *etc*. It also appears that they will offer lay opinions related to batteries in their brief, even though the Joint Intervenor experts have not addressed batteries in connection with reliability issues. The Joint Intervenors believe that substantial increases in these resources, or a combination of these increased resources, could either solve the current reliability issues or eventually ease outage concerns related to the transmission upgrades that they prefer. They ignore the reality that the Company and the Council cannot simply roll the dice on these unsupported optimistic assumptions about speculative resources that may not exist in the future. Again, their suggestions are based on an "anything-but-a-gas-plant" ideology, which has led to some rather unreasonable and highly speculative arguments related to addressing the City's reliability issues.

a. Load reductions over time related to demand side management and solar are speculative and will not address ENO's reliability need.

The Joint Intervenors argue that ENO can simply rely on load reductions over time related to demand side management measures, such as energy efficiency, to address its reliability needs or ease outage concerns related to the transmission upgrades. Joint Intervenors witness Mr. Fagan stated in his Direct Testimony that "ENO can effectively buy itself more time to ease any outage scheduling difficulties by taking steps to further reduce projected system peak demands."[300] Mr. Fagan also apparently believes that load reductions over time could also potentially solve the reliability issues in New Orleans, but, as stated above, he has conducted no analysis related to reliability issues and has not determined any particular basket of resources that will address ENO's reliability needs or ease outage concerns.[301] It is clear that Mr. Fagan has no experience in New Orleans,[302] is not an electrical engineer,[303] is not a transmission planner,[304] and offers no analysis regarding the quantities, location, likelihood, and expected timing[305] of the resources needed to reduce transmission loading over time. As for Joint Intervenors witness Mr. Lanzalotta, who also has no experience in Louisiana, he admitted the following at the hearing:

> **MR. GUILLOT:** All right. At the time of your testimony, you had not done any independent analysis regarding the likelihood of increased energy efficiency to address ENO's reliability issues; fair?
>
> **MR. LANZALOTTA:** Yes.
>
> **MR. GUILLOT:** And no analysis of any specific location of increased energy efficiency to address reliability; right?
>
> **MR. LANZALOTTA:** Right.
>
> **MR. GUILLOT:** No analysis regarding the probability of increased energy efficiency being realized?
>
> **MR. LANZALOTTA:** That's correct.
>
> **MR. GUILLOT:** And no analysis regarding the timing of increased energy efficiency?
>
> **MR. LANZALOTTA** Yes.[306]

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300 Joint Intervenors Exhibit Fagan-1 (Fagan Direct) at 35.

301 *Id.*

302 Tr. (Fagan) 12/19/17, at 14.

303 Joint Intervenors Exhibit Fagan-1 (Fagan Direct) at RMF-1, p. 5.

304 Tr. (Fagan) 12/19/17, at 15.

305 *Id.* at 17, 35.

306 Tr. (Lanzalotta) 4/21/21, at 61-62.

On the other hand, ENO has performed a reliability analysis implementing the full amount of the 2% goal, and cascading outages still occur, indicating that even assuming a substantial amount of incremental DSM, the reliability concerns at issue still exist.[307] This case is substantial because it means that even if the Council had a study in hand indicating that the 2% goal can be met, which it does not, such projected energy savings could not, and will not, be guaranteed by any party in this case, and perhaps more importantly, it means that the savings would nevertheless not address any of the reliability concerns at issue even if they could be achieved.

At the December 2017 Hearing, Company witness Mr. Charles Long strongly cautioned against relying on speculative resources like DSM to address reliability concerns:

> If you can achieve the DSM and it is actually something that you can count on, then, yes it can unload the transmission system. When we do reliability planning, it's something that we must be able to count on. It can't be a maybe. It has to be a must for me to count on it for compliance with reliability standards.[308]

Mr. Long points out that if the Joint Intervenors' advice is followed, the Company could wait to see if load reductions are achieved "over time" to facilitate outage scheduling or solve reliability issues, but no such load reductions may ultimately materialize, leaving ENO customers exposed to outages for an indefinite period.[309] This does not amount to a strategy; it amounts to hope in dangerous assumptions at a time when the reliability of New Orleans is at stake.

The same flaws exist with respect to the Joint Intervenors next suggestion to mitigate the reliability needs or ease outage concerns — increased levels of solar PV installations. Even Joint Intervenors witness Mr. Lanzalotta agreed at the hearing that increased amounts of solar installations "depend on customer behavior" and that "if customers don't buy it, they don't get

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307 *See* ENO Exhibit C. Long-3 (C. Long Rebuttal) at CWL-8 (corrected transmission case 2% DSM-only).

308 Tr. (C. Long) 12/15/17, at 143.

309 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 16.

installed."[310] He also admitted that at the time of his Testimony, he "had not done an independent analysis regarding the ability of distributed resources to affect the reliability issues in New Orleans."[311] Accordingly, the Joint Intervenors again offer no analysis, and as Company witness Mr. Cureington discusses in his Rebuttal Testimony, and as discussed above, there has been a steady declining rate of behind-the-meter solar in New Orleans at a time when the Joint Intervenors advocate dependence on significant increases of solar to address ENO's reliability needs. This evidences the danger in relying on the Joint Intervenors unsupported, overly simplistic and overly optimistic "solutions" to serious reliability issues. Furthermore, as discussed more fully above, the output of solar PV depends on environmental factors like the amount of sun available at a given time, making such resources nondispatchable, meaning that their energy output may not be available when needed for reliability.

Next, the Joint Intervenors offer demand response as a potential solution. Load savings related to demand response occurs when customers agree to curtail their usage when called upon to do so by the utility. Obviously, with respect to outage scheduling, no customer will agree to curtail power for the long durations that would be required for transmission upgrades. So demand response is not a solution to outage scheduling. With respect to addressing the underlying need itself, Joint Intervenors witness Mr. Lanzalotta admitted the following at the hearing:

> **MR. GUILLOT:** All right. At the time of your testimony, you had not conducted any analysis regarding whether demand management can address ENO's reliability needs; correct?
>
> **MR. LANZALOTTA:** That's correct.

310 Tr. (Lanzalotta) 12/21/17, at 64.

311 *Id.* at 64.

> **MR. GUILLOT:** And no analysis regarding the use of demand management or demand response to meet instantaneous changes in demand on ENO's system?
>
> **MR. LANZALOTTA:** Yes.
>
> **MR. GUILLOT:** Yes, an analysis or no, an analysis?
>
> **MR. LANZALOTTA:** I did no analysis.
>
> **MR. GUILLOT:** All right. No analysis into the amount of demand management that will be needed to impact reliability?
>
> **MR. LANZALOTTA:** Yes, that's correct.
>
> **MR. GUILLOT:** And no analysis of any particular location of demand management that will be needed to impact reliability in New Orleans?
>
> **MR. LANZALOTTA:** No analysis, period.[312]

Given Joint Intervenors' reliance on Mr. Lanzalotta's expert opinions, his admission that he's done "no analysis, period" is truly breathtaking; and as explained by Company witness Mr. Charles Long, "it's tough to get somebody to do without something, and sometimes people sign up to do without and then when you actually do without, it's not what they thought it was. So, again, [demand response is] not something I can count on because it's not a guarantee."[313] Mr. Long's concern is that, for example, asking customers to curtail their air conditioner use on the hottest summer days when reliability issues are prevalent may ultimately prove fruitless. If customers find such a request intolerable, which is likely inevitable given the heat in New Orleans, those customers could simply exit the program, converting curtailable load into firm load and exacerbating ENO's reliability issues in the process.

312 *Id.* at 65.

313 Tr. (C. Long) 12/15/17, at 219-20.

In fact, Air Products witness Mr. Brubaker made a similar point at the hearing, testifying that generally there are "very few customers [that] can accept interruptible power" and that Air Products happens to be one of them.[314] Mr. Brubaker stated, however, that should those interruptions adversely affect business operations, "Air Products could simply decide 'I can't tolerate interruptible power. I want it firm'," which would result, according to Mr. Brubaker in "an extra 20 [MW] or so problem to solve."[315] Mr. Brubaker also agreed that Air Products could "simply choose not to curtail its load and pay a penalty instead."[316] These statements evidence the fact that demand response is also speculative as it relates to long-term transmission reliability planning. Moreover, it is not a given that curtailing Air Products' operations would avoid the severe reliability risks facing the area, as the location of load needed to be shed can vary based on the location of the reliability issue that is occurring. And in any case, both Messrs. Long and Movish have made clear that curtailing Air Products alone would not address the reliability issues that would lead to widespread outages, and more non-curtailable customer load would need to be shed. [317]

Simply put, even setting aside the Joint Intervenors' lack of any analysis with respect to the amounts, costs, and likelihood of success related to energy efficiency, solar, demand response, or some combination thereof, Mr. Long's warning that all of these potential resources are "speculative and they don't guarantee that [he'll] be able to produce energy at that location when [he] need[s] it" should be heeded.[318] In contrast, if NOPS is constructed, the Company could effectively press a button to receive the energy needed to stabilize the grid.

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[314] Tr. (Brubaker) 12/20/17, at 179.

[315] *Id.* at 180.

[316] *Id.* at 180.

[317] Tr. (C. Long) 12/15/17, at 127; Advisors Exhibit Movish-1 (Movish Direct) at 20.

[318] Tr. (C. Long) 12/15/17, at 219.

b. Planned ELL Generators, MISO MTEP projects or new auto-transformers will not address ENO's reliability need.

To be clear, all planned generators being constructed by Entergy Louisiana, LLC (i.e., St. Charles Power Station and Lake Charles Power Station)[319] and MISO MTEP transmission projects have been included in ENO's analysis but they will not eliminate the reliability risks at issue in this case, including the risk of cascading outages.[320] St. Charles Power Station will be located a significant distance away from New Orleans, and the currently planned MTEP projects are located on the western end of DSG and do not eliminate the need for local generation in this case. With respect to the MTEP projects, as stated by Company witness Mr. Charles Long in his Rebuttal Testimony, "[t]he Company agrees that these projects are currently underway, but this fact only makes it all the more unreasonable to expect that the Company would be able to obtain five additional outages and undertake the other necessary steps to develop five additional transmission projects in a timely manner."[321] Moreover, as stated by Charles Long at the hearing, these projects are "occurring on the western side of the DSG" and the Company "can get outages over there on the western side."[322] On the eastern side of DSG, however, where New Orleans is located and no generation exists, outages are much more difficult to receive because there is no generation to provide outage flexibility.[323]

In addition, although not supported by their experts' testimony, their questioning at the hearing suggests that the Joint Intervenors will attempt to argue that ENO can simply upgrade two auto-transformers within its service territory to cure the reliability issues in question. They

319 Tr. (C.Long) 12-15-17, at 195.

320 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 18.

321 *Id.* at 18.

322 Tr. (C. Long) 12/15/17, at 183.

323 *Id.*

apparently received this idea from reviewing current MTEP projects, one of which involves an upgrade to an auto-transformer on the western side of DSG. Company witness Mr. Charles Long made clear, however, that receiving outages to upgrade auto-transformers in ENO's service territory would be [redacted] that these are not "constructible upgrade[s]," and that "the risk that would be taken during an outage at those two critical substations would be extraordinary."[324] Given their throw-everything-against-the-wall-in-hopes-that-something-might-stick approach to this proceeding, Charles Long's warning likely will not prevent the Joint Intervenors from advancing their auto-transformer argument, as they seem willing to accept any risk in order to stop the construction of a gas plant; however, the Company cannot base its corrective action plan on upgrades that likely cannot be constructed, and that if constructed, would create "extraordinary risks" to the electric grid. If advanced, the Council should reject these dangerous lay opinions offered by the non-expert Joint Intervenors and their attorneys.

c. Batteries will not address ENO's reliability needs.

Staying true to their theme of drawing conclusions without relevant supporting facts or analysis, the Joint Intervenors questioned a number of witnesses at the hearing as to whether they were "aware" of a limited number of battery installations around the world (*e.g.*, California and Australia), suggesting that the same approach can be used in New Orleans. Again, the Joint Intervenors' own experts have not addressed these battery installations in their Direct Testimony, and no evidence has been introduced pertaining to the limited number of installations referenced in the questioning by the Joint Intervenors' counsel at the hearing. To be clear, nothing contained in the record even remotely suggests the circumstances surrounding their construction,

324 *Id.* at 156-57.

commercial feasibility (*i.e.*, more than 1 installation), discharge limits, or costs related to these referenced battery installations.

For example, it is widely known that batteries have a limited discharge time. This factor alone makes this technology a bad choice given ENO's needs, as Company witness Mr. Charles Long stated at the hearing:

> We did not explore batteries as part of the solution because we needed [a] dispatchable resource. And batteries – first of all, they have to be charged and you have to use the system to charge them . . . and they use more energy to charge them than they return to the system. And then when they do return to the system, they only can discharge for a few hours. So they're just not a dispatchable resource like NOPS where we can turn it on and run it for whatever hours we need it.[325]

Mr. Long testified that the Company did not need to perform a detailed analysis because "battery storage is just not – because of its intermittency, it's not going to solve our reliability problems."[326] When pressed whether the Company performed a detailed analysis regarding battery storage, Mr. Long stated that the technology is not practical because, for example, "a battery can make power for four hours" and that the Company "routinely [has] outages much longer than four hours."[327] Accordingly, as Mr. Long put bluntly, "it won't work."[328] In fact, in a storm situation, as evidenced above during Hurricane Gustav, generation can be needed for long durations of time while transmission is being restored. Thus, if a battery installation is placed at Michoud, customers would end up paying for a costly resource that would prove virtually useless in a storm situation, which is a fatal limitation.

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325 *Id.* at 216.

326 *Id.* at 217.

327 *Id.*

328 *Id.* at 217.

It should also be noted that batteries are net loads, not generators, meaning that they consume more energy than they discharge. Thus, in this particular situation, batteries can add more stress to an already stressed transmission system. There are also other questions related to batteries, such as their asset life and their potential to degrade over time. Rather than making an evidentiary case for batteries, however, like all of their other suggestions, the Joint Intervenors merely speculate that a few battery installations in far-away locations prove that the technology can offset the need for local peaking generation in New Orleans. Stated simply, however, the Council should not take this bet.

The City of New Orleans needs a dispatchable resource that not only can mitigate the risk of widespread outages, but that can also respond to hurricane situations and meet ENO's other reliability needs. Batteries are not the answer.

6. *Combining speculative resources does not make them any less speculative (i.e., the Solar + 2%, case B2).*

In response to a reliability scenario requested by the Council's Advisors, the Company performed a scenario (Requested Case B2) that combined 200 MW of solar with the Council's 2% DSM goal, without the inclusion of either NOPS alternative.[329] The Company has stated multiple times, however, that this is not a realistic scenario and that the Council should not rely on it for purposes of maintaining reliability in New Orleans.[330] First, in Case B2, 200 MW of solar PV is assumed to be interconnected to the Michoud Substation, where additional generation is needed for reliability purposes following the deactivation of the Michoud units.[331] The

[329] As discussed more fully by Company witness Charles Long at p. 41-42 of his Rebuttal Testimony, the error noted by Mr. Movish in his Direct Testimony related to the amount of DSM contained in the load forecasts that incorporated the 2% goal in ENO's reliability analyses only applied to the cases that included the 2% goal. The Company corrected the analyses and there were no changes in the results. ENO Exhibit C. Long-3 (C. Long Rebuttal) at 41-42.

[330] ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 19-20.

[331] ENO Exhibit C. Long-3 (C. Long Rebuttal) at 44.

Company has made clear, however, that this is not a reasonable assumption, as no material amount of solar can be located in New Orleans East.[332] It's simply not feasible given land requirements. For example, at the hearing, the Joint Intervenors provided Company witness Mr. Cureington with one page of his testimony from Docket No. UD-17-05, which indicated that [redacted] MW of solar resources bid into ENO's RFP.[333] Tellingly, however, on another page of that same testimony, it indicates that only [redacted] MW bid into that renewable RFP was proposed to be located in New Orleans, and none was proposed to be located at the Michoud Site where generation is needed for reliability.[334]

The second unreasonable underpinning of Case B2 is the inclusion of the 2% DSM goal.[335] As Company witness Mr. Charles Long stated in his Supplemental and Amending Testimony, and as discussed above, "DSM load reductions are speculative in nature (*i.e.*, capital expenditures on DSM do not guarantee load reductions) and therefore the inclusion of such load reductions in a reliability analysis does not ensure that the Company will remain compliant with NERC Reliability Standards if the reductions do not actually materialize."[336] Mr. Charles Long further stated that "reliability planning should be predicated on what can reasonably be counted on to reliably serve ENO system loads."[337] And even if the Joint Intervenors had a study in hand stating the 2% goal is possible, which they do not, no party can guarantee that those savings will actually be achieved.

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332 ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 20.

333 Sierra Club Exhibit SC-6 (Cureington Docket UD-17-05) at 8.

334 *Id.* at 9; *see also* ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 20.

335 ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 19-20.

336 *Id.* at 19.

337 *Id.* at 20.

At the December 2017 Hearing in this matter, Company witness Mr. Charles Long reiterated his concerns with relying on the unrealistic Case B2:

> **MR. SMITH:** And so DSM can serve to reduce transmission load; right?
>
> **MR. CHARLES LONG:** If you can achieve the DSM and it is actually something that you can count on, then, yes, it can unload the transmission system. When we do reliability planning, it's something that we must be able to count on. It can't be a maybe. It has to be a must for me to count on it for compliance with reliability standards.
>
> **MR. SMITH:** So you just said, though, that in this particular run, you counted on it; is that right?
>
> **MR. CHARLES LONG:** Yeah. We assumed that we could get it all and we assumed that we could interconnect all the solar just to do the analysis that was requested. I don't think that that's possible, but I did the analysis.[338]

In other words, these resources are far from "sure bets," as Mr. Long stated, "they're all speculative and they don't guarantee" anything with respect to reliability.[339] The Company submits, however, that when the reliability of the City of New Orleans is at stake, a sure bet is exactly what is needed. Thus, although the Joint Intervenors will undoubtedly argue that both Case B2 (*i.e.*, 200MW of solar at Michoud plus 2%) and the case that assumes the construction of the 128 MW RICE units produce the same transmission project in 2027, it should be noted that, as the saying goes, one of these things is not like the other — *i.e.*, the construction of the RICE units is a reasonable assumption, but assuming 200 MW of solar at Michoud and the realization of the 2% DSM goal should not be relied upon for purposes of reliability planning. Furthermore, it is also important that only one of these scenarios—the construction of NOPS—will actually ensure that the transmission upgrade in 2027 can actually be constructed by creating

338 Tr. (C. Long) 12/15/17, at 143 (emphasis added).

339 *Id.* at 219.

counter-flow on the system and easing outage concerns. Thus, even if 200 MW of solar could be constructed at Michoud, which it cannot, its output would be intermittent and would not allow for the construction of the transmission upgrade in 2027 by easing line loading whenever it is necessary, and would still rely on achieving a 500% increase in DSM.

It also appears that the Joint Intervenors will attempt to use Case B2, given that the Company used a 35% capacity factor for solar resources, to support an argument that the minimum amount of generation that needs to be installed at Michoud is 70 MW, since 35% of 200 MW is 70 MW. The Joint Intervenors, however, neglect to account for the 2% DSM goal when using this logic, which as stated above, is also speculative and should not be relied on for reliability purposes. To be clear, as stated above, the minimum amount of generation needed at Michoud is 128 MW of dispatchable generation. The Company can be sure that this is the minimum amount because, as also discussed more fully above, a transmission project may still be needed in 2027 to address a minor overload on the system. As Company witness Mr. Charles Long has stated, the transmission project in 2027 indicates that 128 MW is really not enough, but it is enough to make the Company comfortable with waiting given that constructing NOPS will actually facilitate outages to construct the upgrade in 2027. Any reduction in the amount of capacity installed at Michoud would exacerbate the overload in 2027, making the upgrade more likely, and would potentially create more serious overloads in earlier years.

In addition, the Company used a 35% capacity factor for solar because it is undisputed that at times, its output can be zero. As Company witness Mr. Charles Long stated at the hearing, "when the sun is covered with clouds, they won't produce any" output.[340] Mr. Long testified that ENO gave solar "some benefit of the doubt because when the sun is shining at peak,

[340] *Id.* at 150.

when the sun is low in the sky, output is reduced, but not all the way to zero,"[341] but said that he cannot "rely on that for transmission reliability because it may not be there at all."[342] Joint Intervenors witness Mr. Lanzalotta admitted at the hearing that "during the day . . . the output could be drastically reduced."[343] Accordingly, using a 35% capacity factor for purposes of the analysis was completely reasonable.

7. *High-impact transmission outages are at issue in this case, not low-impact distribution outages.*

In response to the current and persisting threat to the transmission grid posed by not having local generation, the Joint Intervenors have purposefully attempted to conflate distribution reliability issues with transmission grid reliability issues. The Joint Intervenors are either themselves confused, or have obviously made the calculation that the public and the Council cannot differentiate between these two very separate and distinct issues. The fact is, however, that the risk of high-impact, widespread transmission outages in this case is very different than the rather localized, low-impact distributions outages that the Joint Intervenors have been referencing. Company witness Mr. Charles Long summarized this difference as follows:

> It's important to understand the difference between distribution outages [that] happen to a few customers in a neighborhood or on one small feeder with what we're talking about the risk is for transmission outages. There are distribution outages all the time in any distribution system. The systems are -- That's just they're in neighborhoods and there's trees over the top of them and all that, but the outages that we could experience on the transmission system would outage thousands of customers at the same time and without warning. And so there are distribution outages, but the

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341 *Id.*

342 *Id.*

343 Tr. (Lanzalotta) 12/21/17, at 62-63.

> outages that can be caused by the transmission issues that we talk about are far, far greater than that.[344]

By way of analogy, outages stemming from transmission issues are akin to the interstate system being closed for long durations, which would cause traffic problems throughout the City. Distribution outages, on the other hand, are akin to a neighborhood street being closed, which will cause traffic problems for one neighborhood. Moreover, as explained by Company CEO Mr. Charles L. Rice, Jr. in his Rebuttal Testimony, the Company has a capital budget aimed at improving the performance of its distribution system;[345] but to be clear, that is a separate and distinct issue.

8. *Once a baseline level of reliability is established, the Company supports resources like solar and DSM to drive other benefits for customers.*

The Council should be aware that the Company is not opposed to exploring any of the types of resources that the Joint Intervenors have proposed generally that may address needs other than reliability problems at issue in this case. For example, the Company has conducted a Renewables RFP and remains committed to adding 100 MW of renewables to its resource portfolio. In fact, the Joint Intervenors cited to a Council docket pertaining to a 5 MW rooftop project being proposed by the Company at the December 2017 Hearing. The Company's Energy Smart Program is also evidence of its commitment to resources like energy efficiency. To be clear, however, these resources can produce benefits to customers and have a place in ENO's portfolio, but they cannot meet the current reliability need. Company witness Mr. Charles Long summarized this point at the hearing, stating as follows:

> One of the things about the RICE unit is that, you know, once the basic needs are met in the city for transmission reliability, then you can do some of those other things and not have to worry

[344] Tr. (C. Long) 12/15/17, at 202.

[345] ENO Exhibit Rice-4 (Rice Rebuttal) at 24-25.

> about reliability. Some of the other alternatives that, you know, people are interested in like solar, batteries, and DSM, but we're behind right now. We need to establish a basic level of reliability, then some of that stuff is more feasible. And the RICE unit is really good, I think, for that kind of thing because it's so flexible.[346]

Accordingly, while NOPS is needed to establish a baseline level of grid reliability that these other resources cannot offer, neither the Council, nor any party in this case should interpret any of the arguments advanced by the Company as a rejection of those resources for other purposes. The Company will continue to explore opportunities related to these other resources, but the record is clear in this case that they cannot obviate the need for NOPS.

II. <u>Whether either of ENO's choices of technology(ies) are in the public interest</u>

ENO's 2015 IRP identified a long-term need for capacity as well as a need for long-term peaking and reserve resources.[347] Both the proposed CT and the Alternative Peaker are technologically suited for serving peaking and reserve roles.[348] Both technologies are capable of starting quickly and ramping to full load within minutes.[349] This quick-start capability supports local area reliability and could help facilitate the integration of renewable resources in or near the Company's service area because it addresses the intermittency associated with renewables.[350] Both NOPS options support the Company's planning objectives and are consistent with supply role needs.[351] An additional benefit of the Alternative Peaker is its black-start capability, which

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[346] Tr. (C. Long) 12/15/17, at 229-30.

[347] ENO Exhibit Cureington-2 (Cureington Direct) at 9.

[348] *Id.* at 25; ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 12-13.

[349] ENO Exhibit Cureington-2 (Cureington Direct) at 26; ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 12.

[350] ENO Exhibit Cureington-2 (Cureington Direct) at 26; ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 12-13.

[351] ENO Exhibit Cureington-2 (Cureington Direct) at 26; ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 6.

could aid in restoring power in the event of widespread transmission system outages during a major storm.[352] As will be discussed below, none of the other resource possibilities suggested by the Joint Intervenors can fulfill the Company's supply role needs.

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

ENO has shown that the selection of the CT unit is in the public interest. ENO's 2015 IRP indicated a need for peaking and reserve capacity. The NOPS Project Team evaluated several different technologies, and the proposed CT was determined to be the better economic option for ENO's customers, considering the total relevant supply cost method, which included comparing fixed costs, variable production cost, MISO capacity purchase costs, and transmission.[359] The proposed CT supports the Company's long-term planning objectives and is consistent with its supply role needs.[360]

The CT option consists of one Mitsubishi Hitachi Power Systems America ("MHPSA") 501 GAC CT, which would provide approximately 226 MW (nominal) of summer generating capacity.[361] Other Entergy companies have had positive prior experiences with Mitsubishi as a supplier of gas and steam turbines and received superior service.[362] Other Entergy Operating Companies ("EOCs") have purchased the same turbine for the St. Charles, Lake Charles, and

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352 ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 28.

359 ENO Exhibit J. Long-2 (J. Long Direct) at 8.

360 ENO Exhibit Cureington-2 (Cureington Direct) at 26.

361 ENO Exhibit J. Long-2 (J. Long Direct) at 4. The 226 MW output is based on summer conditions of 97° F and 59% relative humidity. The amount of power that the CT can generate is correlated to the density of the air as it goes into the gas turbine, such that the CT has a greater output with denser air and a lower output with less dense air. Mr. Jonathan Long noted that the summer conditions are meant to provide a conservative estimate of maximum output and that the CT's output could actually be higher than 226 MW because New Orleans frequently experiences humidity higher than 59% in the summer, and higher humidity would actually lead to a greater output because the air would be denser. *See id.* at 5; Tr. (J. Long) 12/18/17, at 90-91.

362 ENO Exhibit J. Long-2 (J. Long Direct) at 8; Tr. (J. Long) 12/18/17, at 47.

Montgomery County Power Stations.[363] ENO witness Mr. Jonathan Long, who has developed power generation facilities for over 30 years, expressed the opinion that this is the "best gas turbine on the market" to meet ENO's needs and that there would be benefits from an operations and maintenance perspective by using the same turbine for NOPS.[364]

Importantly, the CT fulfills both the capacity and reliability needs of ENO for the Company's full planning horizon. As discussed above, ENO has demonstrated a capacity need of 99 MW in 2026, growing to 248 MW by 2036.[365] The CT, by providing an additional 226 MW of capacity, addresses the majority of this overall capacity need over the next 20 years.[366] ENO additionally has a reliability need—without NOPS, the City faces the risk of uncontrollable cascading outages,[367] which could lead to, at a minimum, approximately 49,000 ENO customers out of service.[368] Adding the CT unit "will eliminate all grid reliability issues within the current 10-year planning horizon."[369] Advisors witness Mr. Movish agrees that the CT "would fully mitigate ENO's transmission reliability issues without the need to construct any transmission upgrades."[370]

On top of addressing the capacity and reliability needs of ENO, the CT will provide additional benefits. These benefits include: avoiding costly and time-consuming transmission upgrades; providing the capability to back up renewable resources when they are not available; facilitating more load-serving capability and system restoration following extreme weather (*e.g.*,

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363 Tr. (J. Long) 12/18/17, at 47.

364 *Id.*

365 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 7.

366 *Id.* at 11.

367 ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 9-10.

368 Advisors Exhibit Movish-1 (Movish Direct) at 43.

369 ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 13.

370 Advisors Exhibit Movish-1 (Movish Direct) at 4.

hurricanes and tornadoes); providing more of a hedge against congestion on the transmission system that tends to increase locational marginal pricing in the New Orleans Load Zone; facilitating planned transmission and generation maintenance outages in the load pocket and mitigating the risk associated with unplanned outages; and providing a quick-start, fast ramping resource capable of responding to real-time operational needs of the ENO system.[371] ENO's selection of the CT is undoubtedly in the public interest.

Indeed, although the Company also has proposed the Alternative Peaker, and it recognizes that the Council must balance several factors to choose between the two options, the CT remains the best option for ENO's customers. On a $/kW basis, the CT has a lower supply cost than the Alternative Peaker, and there are benefits created by the addition of local generation that increase as the size of the local generator increases, such as larger reliability margins, a greater hedge against market and supply risks and unit retirements in Amite South and DSG, and creating more reactive power and flexibility to take transmission outages.[372] But the Company's load forecast moderated after it proposed the CT, and, even though its need under the updated forecast still supports construction of the CT, the Company has presented the RICE option as a viable alternative to the CT that will also provide customers with essential reliability benefits, as the Company discusses further below.[373]

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

ENO also has shown that the Alternative Peaker is in the public interest and is a reasonable alternative to the selection of the CT unit to provide needed capacity and reliability benefits to ENO's customers. The RICE units have received support from the Advisors and from

371 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 4.

372 ENO Exhibit Rice-3 (Rice Supplemental and Amending Direct) at 7-8.

373 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 3-16.

Air Products. Advisors witness Mr. Rogers recommended "that the Council strongly consider favoring the 128 MW project."[374] Air Products witness Mr. Brubaker echoed the Advisors' preference for the RICE units.[375]

The RICE option would consist of seven Wärtsilä 18V50SG reciprocating internal combustion engines.[376] Reciprocating engines use the expansion of hot gases to push a piston within a cylinder, converting the linear movement of the piston into the rotating movement of a crankshaft to generate power.[377] The Company engaged WorleyParsons, a qualified and respected engineering firm, to conduct a study regarding the Company's potential options for a smaller resource.[378] That analysis of technology resources in the 100 to 130 MW range indicated that the RICE units had the lowest levelized cost of electricity on a $/MWh basis of the five technologies considered, low water usage, a low emissions profile, the ability to support renewable resources, and black-start capability.[379]

The RICE resource, like the CT, provides capacity and reliability benefits to ENO customers. The RICE option addresses ENO's overall capacity need in the first ten years of the planning horizon and mitigates exposure to market and supply related risks.[380] The RICE units address many of the reliability concerns by preventing the risk of cascading outages.[381] Although additional transmission investment may be needed, the potential overloads are relatively minor and not anticipated to be an issue until 2027, which provides the Company time to determine

374 Advisors Exhibit Rogers-2 (Rogers Direct) at 3.

375 *See* Air Products Exhibit Brubaker-3 (Brubaker Additional Direct) at 3.

376 ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 1.

377 *Id.* at 7.

378 *Id.* at 6.

379 *Id.* at 6, 10.

380 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 12.

381 ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 13.

whether it should move forward with transmission upgrades or potentially add an additional RICE unit.[382]

Like the CT unit, the RICE units can start and achieve full load in a very short period of time and can start and stop multiple times in a single day.[383] This fast start capability is a great option in a peaking or emergency situation.[384] This also helps to support renewable resources by providing generation when renewable resources are not available.[385] As Mr. Jonathan Long explained at the December 2017 Hearing:

> These units were chosen for their flexibility. As the interest in having more renewables in the area and our commitment to deliver more renewables and the way that those renewables act on our system, the need for flexibility is greater, will be greater as that happens, and so these units have greater flexibility, including the ability to start and stop daily.[386]

Although the CT and RICE options both have capacity and reliability benefits, the RICE units have the additional benefit of black-start capability, which allows the plant to start up under its own power without a backfeed of power from the electric grid.[387] As Advisors witness Mr. Movish describes, black-start capability can "support restoration of service after a major outage or storm event, and the ability to provide a source of power to ENO's critical loads in the event of an outage."[388] Advisors witness Mr. Rogers stated that he believed that "the ability to black start the RICE Alternative in the event that New Orleans becomes disconnected from the

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382 *Id.*

383 ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 12.

384 *Id.*

385 *Id.*

386 Tr. (J. Long) 12/18/17, at 42.

387 ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 13.

388 Advisors Exhibit Movish-1 (Movish Direct) at 4-5.

regional transmission grid is an advantage that is invaluable and cannot be overlooked."[389] Furthermore, the Advisors suggested the possibility of the RICE units potentially providing a source of power for the S&WB Carrolton facility in the event that S&WB's generation was impaired or inoperable,[390] and ENO has indicated that it has begun exploring that possibility.[391]

Air Products witness Mr. Brubaker has suggested that ENO "consider adding fewer than seven RICE units at this time, and instead install fewer than seven units, but construct the infrastructure necessary to permit addition of the remaining units if future circumstances support adding more capacity."[392] The Company has considered this issue, and, for a number of reasons, reducing the capacity of the Alternative Peaker is not justified or in the interest of the Company's customers. First, it should be expected that installing fewer than seven units will cost more on a $/kWh basis than the seven-unit plant will cost, and it is not clear that the costs of mobilizing contractors to the site for a second time in the future and obtaining any necessary regulatory approvals would support delaying the installation of two or three units from an economic standpoint.[393] As Mr. Jonathan Long explained, there are economies of scale that come with installing seven RICE units now.[394] Second, fewer RICE units would not provide the needed reliability benefits of seven RICE units.[395] And, importantly, Mr. Brubaker's testimony and observations were based on ENO's capacity position and not local reliability benefits as he

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389 Advisors Exhibit Rogers-2 (Rogers Direct) at 51.

390 Advisors Exhibit Movish-1 (Movish Direct) at 5.

391 ENO Exhibit C. Long-3 (C. Long Rebuttal) at 44-45 (presenting the results of a preliminary assessment involving the possibility of black-starting the RICE resource and supplying start-up power to the S&WB's facility in order to start the pumps located within the S&WB facility).

392 Air Products Exhibit Brubaker-3 (Brubaker Additional Direct) at 3-4.

393 *See* ENO Exhibit Cureington-8 (Cureington Rebuttal) at 57-58; *see also* Tr. (J. Long) 12/18/17, at 129, 132-33.

394 Tr. (J. Long) 12/18/17, at 128-29.

395 *See* Tr. (C. Long) 12/15/17, at 225.

admitted at the hearing.[396] As described more fully above in Section II(B), Mr. Charles Long testified that reducing the number of RICE units to five would leave ENO with insufficient capacity to address reliability concerns, and that mitigating reliability concerns is "borderline" with 128 MW provided by seven RICE units.[397] Furthermore, ENO anticipates having a capacity shortfall of 248 MW in 2036, meaning that ENO will ultimately need the full 128 MW of capacity that the seven units would provide.[398] Finally, if existing legacy units in ENO's portfolio deactivate earlier than expected or if load increases more than projected, the Company's resource needs will increase, and the seven RICE units will provide needed capacity.[399]

C. Whether ENO appropriately considered a full range of options to meet the <u>identified need</u>

ENO appropriately considered a full range of options to meet its identified supply needs. As the Company discusses below, (1) ENO's 2015 IRP included an extensive review of options for meeting the long-term needs of the Company's customers, (2) possibilities other than new gas-fired generation would not meet ENO's supply and reliability needs, and (3) a formal competitive process to select a resource addition for ENO would have been costly to customers and wasteful considering the Company's specific supply and reliability needs.

1. ENO's 2015 IRP process determined that CT capacity is the best alternative to meet ENO's identified supply need, and subsequent analyses confirm that result and that the RICE resource is a reasonable alternative that provides many of the same benefits as the proposed CT.

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396 Tr. (Brubaker) 12/20/17, at 175-76.

397 Tr. (C. Long) 12/15/17, at 225.

398 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 58.

399 *Id.*

Joint Intervenors witness Mr. Fagan contends that ENO did not perform a "rigorous analysis" of resource alternatives,[400] but he ignores entirely ENO's 2015 IRP. Indeed, Mr. Fagan confirmed at the hearing that he did not even review the 2015 IRP when he prepared his testimony,[401] and that alone is reason to reject his contention. An IRP is designed to consider a wide range of different future scenarios and resource alternatives – precisely the type of analysis described by Mr. Fagan in his testimony.[402] Consistent with this objective, in developing its 2015 IRP, ENO conducted a DSM Potential Study, Generation Technology Assessment, and Portfolio Evaluation, which thoroughly evaluated a range of viable supply and demand-side resource alternatives capable of meeting the Company's long-term capacity and peaking and reserve needs.[403] The 2015 IRP documented the extensive analysis undertaken, and stakeholder input sought, over the course of nearly 18 months of work, involving hundreds of hours of data review, modeling, post-processing analysis, stakeholder review, public technical conferences, and reports to the Council.[404] That extensive process resulted in the conclusion that ENO has a substantial need for peaking and reserve capacity, and that a CT unit is the lowest reasonable cost resource capable of meeting that need.[405] During the course of this docket, even as load forecasts have moderated, ENO has demonstrated that the CT is still the best resource to meet its capacity and reliability needs.[406] As has been discussed previously, the RICE resource is a reasonable

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400 Joint Intervenors Exhibit Fagan-2 (Fagan Direct) at 10.

401 Tr. (Fagan) 12/19/17, at 16-17.

402 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 59.

403 ENO Exhibit Cureington-2 (Cureington Direct) at 9.

404 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 59.

405 *Id.*

406 *See* ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 5 ("the CT is the most cost-effective means of addressing the Company's identified long-term planning needs while considering risk"); ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 13 ("[a]dding a unit with an output of 226 MW will eliminate all grid reliability issues within the current 10-year planning horizon").

alternative to the CT, providing needed capacity and reliability benefits. Analyses conducted in connection with the Requested Portfolios support the result that either proposed NOPS resource is "the best alternative for addressing ENO's needs, especially considering the local reliability, storm response, and the energy and capacity market hedge it provides."[407]

2. *Other options do not meet ENO's needs or provide the same benefits as the CT and RICE units.*

ENO has considered other options to meet its needs, such as other natural gas technology, transmission upgrades, and a combination of solar, DSM, and batteries. None of these other options meet ENO's reliability and capacity needs, nor do they provide the same benefits as NOPS.

Technology assessments show that the CT and RICE resources selected by ENO are the best options in their respective capacity ranges. As discussed above, the Company conducted a technology assessment in 2015 that considered four large frame CTs, two aero derivative CTs, and one internal combustion engine.[408] That analysis supported the selection of the Mitsubishi CT as the preferred technology because it provides the highest capacity rating and lowest supply cost of the seven technologies evaluated, in addition to having a relatively low heat rate and competitive ramp rates to provide operational flexibility.[409] A subsequent technology assessment in March 2016 confirmed that the 226 MW CT was the more economic choice as compared to installing one smaller CT early in the planning horizon and then another smaller CT several years later.[410] Production cost modeling presented in Mr. Cureington's Supplemental Direct Testimony in November 2016 also confirmed that the 226 MW CT was the most cost-effective

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407 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 61.

408 ENO Exhibit Cureington-2 (Cureington Direct) at 35; Exhibit SEC-5, p. 11-15.

409 *Id.* at SEC-5, p. 14.

410 *Id.* at 36-41; Exhibit SEC-6.

alternative for meeting ENO's identified long-term capacity needs.[411] Following the suspension of this docket in the spring of 2017, ENO engaged WorleyParsons to conduct a study regarding potential options for a smaller resource.[412] This study determined that seven Wärtsilä RICE units had the lowest levelized cost of electricity of the five technologies evaluated in the 100 to 130 MW range.[413]

As discussed in detail above, transmission upgrades are not a viable alternative to constructing NOPS. As Mr. Charles Long points out, transmission only moves power around, but "it cannot produce electrical energy, capacity, or much needed dynamic reactive power in the DSG load pocket."[414] Nevertheless, the Company conducted an analysis that found, in the absence of NOPS, that five transmission upgrades would need to be constructed.[415] There are significant concerns, however, regarding the constructability of those transmission upgrades, including soil condition, obstructions, and environmental challenges that would increase the cost of construction.[416] Mr. Charles Long noted that these upgrades would require many long outages that "would span many months over many peak hours,"[417] and that getting enough outages to construct these upgrades could take many years because the outages can only be taken at the lowest load times.[418] While Mr. Charles Long opined that it could take eight to ten years to finish all the transmission upgrades,[419] he also expressed skepticism that it could be done at all.[420]

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411 ENO Exhibit Cureington-4 (Cureington Supplemental Direct) at 8; Exhibit SEC-9.

412 ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 6.

413 *Id.* at 10.

414 ENO Exhibit C. Long-2 (C. Long Supplemental and Amending Direct) at 16.

415 *Id.* at 10-11.

416 *Id.* at 17.

417 Tr. (Charles Long) 12/15/17, at 193-94.

418 *Id.* at 197-98.

419 *Id.* at 207-08.

Joint Intervenors have suggested that some combination of renewable resources, increased DSM, and battery resources could eliminate the need for NOPS. As discussed in previous sections, those resource possibilities are not an adequate replacement for NOPS. Regarding solar resources, DSM, and batteries, Mr. Charles Long noted that "[n]one of them are sure bets. They're all speculative and they don't guarantee that I'll be able to produce energy at that location when I need it."[421] In other words, the possibilities mentioned by the Joint Intervenors are not consistent with ENO's supply needs. As Mr. Jonathan Long testified, "we were looking for a peaking resource that could come online when needed, operate as long as needed, and batteries wouldn't fulfill that resource."[422] Simply put, New Orleans is facing serious reliability issues, and it needs a resource that it can count on. No witness has put forth testimony that ENO could count on renewable resources, DSM, and batteries to solve its reliability issues. And none of the Joint Intervenors' witnesses have put forth a specific combination of resources to meet *both* capacity and reliability needs, much less an economic analysis of costs to ENO's customers. The Council should reject the Joint Intervenors' invitation to cast aside the results of the Company's long-term planning processes in favor of unsupported speculation.

3. A more formal RFP process was not necessary to identify and evaluate ENO's supply options, and it would have been costly to customers.

Certain witnesses for the Joint Intervenors and Air Products have criticized ENO for not conducting a formal RFP or competitive all-source solicitation to fulfill its identified resource

420 *Id.* at 171.

421 *Id.* at 219.

422 Tr. (J. Long) 12/18/17, at 81.

needs.[423] As ENO witness Ms. Shauna Lovorn-Marriage explains, however, such a process was unwarranted here for several reasons.[424] First, it is clear from the record in this case, and as described more fully above, that a specific type of generation is needed in a specific location—a peaking resource located at Michoud. Holding an open-source RFP to encourage other technology types at other locations will not meet this need. Moreover, the Council's rules and regulations do not require that an RFP be conducted prior to adding generating capacity intended to serve Council-jurisdictional customers,[425] and Joint Intervenors witness Mr. Philip Henderson has recognized that there may be "legitimate reasons [why] a utility or utility regulator might determine to not use a competitive procurement process in certain instances."[426] One such reason is cost to customers: RFPs are expensive and they take time to complete.[427] The time that it takes to complete an RFP process can delay customers' realization of the reliability and economic benefits that come with needed incremental generation at a time when a unit is needed for reliability as soon as possible.[428]

In this case, it would have been improper to saddle customers with the cost of an RFP process or all-source solicitation. In Resolution R-15-524, the Council recognized the potential need to replace Michoud Units 2 and 3 with local generation, and the record of this case establishes both reliability needs and reliability benefits from constructing NOPS at the Michoud

423 Joint Intervenors Exhibit Henderson-1 (Henderson Direct) at 2; Air Products Exhibit Brubaker-1 (Brubaker Direct) at 3; Joint Intervenors Exhibit Stanton-2 (Stanton Direct) at 23. At the December 2017 Hearing, Dr. Stanton deferred entirely to Joint Intervenors witness Mr. Henderson on competitive procurement issues. Tr. (Stanton) 12/21/17 at 26-27.

424 ENO Exhibit Lovorn-2 (Lovorn-Marriage Rebuttal) at 19-21.

425 *Id.* at 19.

426 Joint Intervenors Exhibit Henderson-1 (Henderson Direct) at 10.

427 ENO Exhibit Lovorn-2 (Lovorn-Marriage Rebuttal) at 20.

428 Tr. (Lovorn-Marriage) 12/20/17, at 38. As Ms. Lovorn-Marriage testified at the hearing, even if ENO charged bidders fees to participate in an RFP, those fees would not necessarily be sufficient to cover the entire cost of the RFP process, which includes independent monitoring and analysis.

Site. A third-party would need to have their own site and their own technology, whereas, for NOPS, ENO already owns the site that brings reliability benefits to the system.[429] That gives ENO a likely cost advantage over any other potential supplier.[430] With respect to competitive all-source solicitation, as suggested by Joint Intervenors Witnesses Mr. Henderson and Dr. Stanton, it is clear that such a process "would have been useless to address ENO's need for peaking capacity, as this need cannot be met through demand-side management or intermittent supply side resources."[431] These alternatives are not suitable to fulfill ENO's reliability and local capacity needs and would very likely keep New Orleans customers exposed to cascading outages for an indefinite amount of time.[432] Furthermore, because there are no local generating resources in New Orleans that could meet the Company's reliability need, Mr. Brubaker's suggestion that ENO should have explored potential Purchased Power Agreements with third parties is inappropriate.[433]

The unique aspects of ENO's capacity and reliability needs support fully the Company's process for proposing NOPS, and the costs of an RFP process or all-source solicitation would not have been in the interests of ENO's customers. The major cost component of ENO's proposed self-build, the contract for Engineering, Procurement and Construction ("EPC"), was tested through a competitive selection process, and that and other risk mitigation measures that ENO discusses later in this brief provide protections for customers that serve the public interest.

III. <u>Whether ENO's selection of the Michoud Site is reasonable</u>

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429 ENO Exhibit Lovorn-2 (Lovorn-Marriage Rebuttal) at 20.

430 *Id.*; Tr. (Lovorn-Marriage) 12/20/17, at 43-44.

431 ENO Exhibit Lovorn-2 (Lovorn-Marriage Rebuttal) at 20.

432 *Id.*

433 *Id.* at 22.

For multiple reasons, the record evidence confirms that the Michoud Site is not only reasonable, but ideal for the construction of NOPS. First, because of ENO's unique planning circumstances, adding capacity at the Michoud Site provides the most benefits to ENO's customers. Of the two sites that ENO owns in New Orleans, Michoud had numerous advantages over the other site. Second, NOPS is not anticipated to have adverse effects regarding groundwater or flooding. Third, the air emissions from NOPS will comply with all applicable environmental regulations, which are designed to be protective of human health. Fourth, ENO has conducted extensive outreach to engage and inform the community regarding its plans for NOPS. Finally, NOPS will not result in environmental injustice.

At the December 2017 Hearing, Mr. Jonathan Long offered the following summary of why Michoud is the ideal site for NOPS:

> [T]here are no residentially zoned properties or residences at the fence line of this site, which is actually unusual in my experience in developing plants in this region. This site has a number of things that are very attractive about it. I understand from Mr. Charles Long that there's a need for power for reliability at this site. The infrastructure that is there in terms of fuel supply, water supply, and transmission interconnection are excellent. And, also, we've owned and operated on this site for at least 50 years and our knowledge of this site is also excellent, which is very much a risk reducing factor. So as sites for new power plants go, all of those things taken into account, this is an excellent site.[434]

A. Due to ENO's unique planning circumstances, the Company's needs are best <u>addressed with a plant located at the Michoud Site.</u>

ENO is located at the far eastern end of the DSG load pocket, which is surrounded by water on three sides and which is itself nestled inside the Amite South load pocket, thus making the region highly reliant on local generation given the limited set of transmission lines to import

[434] Tr. (J. Long) 12/18/17, at 127.

power from West to East.[435] Currently, however, there is no local generation in the City, so ENO is 100% reliant on transmission to serve its load; and, as discussed more fully in Section II(B), generation is needed in an exact location, at the Michoud Site, to replace the retired Michoud units and accordingly mitigate a host of reliability concerns.[436] As Mr. Cureington explained, the vast majority of ENO's generating capacity is located outside the DSG load pocket, and the Company relies, in part, on aging gas-fired generation put in service over 40 years ago to serve its load.[437] More specifically, Mr. Cureington testified that [redacted]% of the Company's generation is located outside of LRZ 9, namely in LRZs 8 and 10, whereas 100% of the Company's load is located in LRZ 9.[438] This reliance on generation outside of LRZ 9 exposes customers to the potential for separation of PRA clearing prices.[439] Deploying new resources such as NOPS within LRZ 9 would partially mitigate that risk by providing an additional source of capacity inside LRZ 9.[440]

Given these benefits, it was reasonable for ENO to select the Michoud Site. This selection is also consistent with Council Resolution R-15-524, which directed ENO to "use reasonable diligent efforts" to develop peaking generation capacity within the City and to "fully evaluate Michoud or Paterson" as potential sites.[446] ENO's evaluation of the two sites complied with that portion of the directive from the Council.[447]

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435 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 9-10.

436 *Id.* at 8.

437 *Id.* at 11.

438 *Id.* at 57.

439 *Id.* at 12; ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 22-23.

440 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 12; ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 23.

446 Resolution R-15-524, at 12; *see also* ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 19-20.

447 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 20.

In addition, it should be noted that the Michoud Site had several advantages over the other site owned by ENO in New Orleans, A.B. Paterson.[448] Michoud is located close to three major gas pipelines, has existing office building infrastructure, and has available bays in the high-voltage switchyard for interconnection to the transmission system.[449] In addition, and most importantly, the Michoud Site is more strongly interconnected to the transmission system in the Company's service area and the DSG load pocket than is the Paterson Site, meaning that placing NOPS at Michoud would have many more positive effects on transmission reliability in the DSG load pocket than other locations, including Paterson.[450]

B. Siting the plant at Michoud will have no adverse effects regarding groundwater withdrawal or flooding.

1. Independent and unrefuted scientific analyses confirm that neither NOPS unit will increase subsidence or pose a risk to area homes or infrastructure.

The evidence in the record includes independent and industry-accepted analyses, which prove that neither the CT nor the Alternative Peaker will increase subsidence in New Orleans.[451] The analyses were performed by Dr. George Losonsky, a recognized expert in the scientific community who holds a Ph.D. in Hydrogeology and has over 30 years of real-world experience in water resource risk management and problem solving.[452] Dr. Losonsky summarized these analyses as follows:

> My independent evaluation involved the use of geotechnical/hydrogeological conceptual site models as well as

[448] ENO Exhibit Cureington-8 (Cureington Rebuttal) at 77; ENO Exhibit Cureington-2 (Cureington Direct) at 41-42.

[449] ENO Exhibit Cureington-8 (Cureington Rebuttal) at 77; ENO Exhibit Cureington-2 (Cureington Direct) at 42.

[450] ENO Exhibit Cureington-8 (Cureington Rebuttal) at 77.

[451] *See* ENO Exhibit J. Long-3 (J. Long Supplemental Direct) at JEL-6; ENO Exhibit Losonsky-1 (Losonsky Supplemental and Amending Direct) at GL-2 and GL-3.

[452] *See* ENO Exhibit Losonsky-1 (Losonsky Supplemental and Amending Direct) at GL-1.

drawdown and consolidation calculations, the latter of which provides the Council with a **<u>conservative</u>, <u>scientific</u> quantification of the <u>worst-case</u> <u>scenario</u> of the possible impacts of groundwater usage associated with NOPS <u>for</u> <u>50</u> <u>years</u> of operating the plant**. These analyses are on par with, and in some cases above and beyond, industry standards for any analysis of groundwater usage impact assessments and they support my independent and sworn representations to the Council that **(i) neither of the proposed NOPS units will increase or contribute to subsidence in New Orleans East or the surrounding areas, (ii) neither unit will cause differential settlement, and, consequently, (iii) neither unit will pose any risk to the integrity of area infrastructure, including the HSDRRS or other flood protection infrastructure**.[453]

Dr. Losonsky's undisputed calculations employ methods of quantifying the possible impacts of groundwater usage that have been scientifically accepted for many decades.[454] The calculations provide a conservative (worst-case) prediction of groundwater withdrawal risks because they assume that either unit would be withdrawing the maximum amount of groundwater required for operation 365 days per year, and 24 hours per day, despite the fact that neither unit would operate at this frequency or withdraw water at this level.[455] The calculations add another level of conservatism by assuming that no prior groundwater pumping has occurred at the site.[456] As Dr. Losonsky notes, and as the scientific principles discussed in his reports confirm, less potential for consolidation settlement due to pumping exists in areas where pumping has already occurred.[457] Thus, the calculations Dr. Losonsky performed overstate the

453 *See* ENO Exhibit Losonsky-2 (Losonsky Rebuttal) at 20 (emphasis added).

454 *See* ENO Exhibit Losonsky-1 (Losonsky Supplemental and Amending Direct) at GL-2, p. 3 ("Hydrogeologists and engineers designing groundwater withdrawal wells have been successfully using analytical solutions to predict the hydraulics of aquifer response to pumping since the early 1930's . . .").

455 *See id.* at 11; Exhibit GL-2, p. 8; and ENO Exhibit Losonsky-2 (Losonsky Rebuttal) at 11.

456 *See* ENO Exhibit Losonsky-1 (Losonsky Supplemental and Amending Direct) at 15.

457 *Id.* at 16.

possible impacts of pumping because they assume that no prior pumping has occurred when, in fact, pumping at a significantly higher rate occurred at this site for decades.[458]

Even with the multiple layers of conservatism that the above assumptions bring to Dr. Losonsky's models, the calculations demonstrate the worst-case possible impacts of groundwater pumping required for NOPS to be less than miniscule. As described in testimony, the calculations predict total consolidation settlement, for an assumed 50 year operation of NOPS, of 0.04 inch for the CT unit and consolidation settlement of less than 0.002 inch for the Alternative Peaker.[459] In the unlikely event that such additional consolidation settlement did occur,[460] it would occur between 500 and 650 feet below the surface of the earth[461] and would not be expressed as subsidence at the ground surface.[462] The results of these calculations support Dr. Losonsky's sworn and scientifically-verified representations to the Council that "it is my independent, professional opinion that neither the CT unit nor the Alternative Peaker will increase or contribute to subsidence in New Orleans East or the New Orleans Metro area."[463]

Dr. Losonsky is also a former Commissioner of the South Louisiana Flood Protection Authority-East ("SLFPA-E")[464] and assisted the SLFPA-E in its efforts to implement the

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458 *See* ENO Exhibit J. Long-2 (J. Long Direct) at 39. Joint Intervenors Witness Dr. Kolker also admitted that water withdrawal for NOPS would be "significantly less than the water withdrawal that was occurring at Michoud." *See* Tr. (Kolker) 12/20/17, at 167.

459 *See* ENO Exhibit Losonsky-2 (Losonsky Rebuttal) at 6.

460 *See* ENO Exhibit Losonsky-1 (Losonsky Supplemental and Amending Direct) at 16 ("Since a higher flow rate has already been applied to the New Orleans-Gonzales aquifer in the past, this settlement has already occurred, and continued pumping at the level proposed for operation at the CT unit will not cause additional settlement."). *See also id.* at 17 (stating the same conclusion for the Alternative Peaker).

461 *See* ENO Exhibit Losonsky-2 (Losonsky Rebuttal) at 6.

462 *Id.* at 13.

463 *Id.* at 6.

464 Governor Kathleen Blanco appointed Dr. Losonsky to serve on the SLFPA-E. Tr. (Losonsky) 12/19/17, at 83-84.

Hurricane and Storm Damage Risk Reduction System ("HSDRRS").[465] As such, Dr. Losonsky is the only witness in this proceeding who is qualified to provide an opinion on whether the proposed location and operation of NOPS creates any risks to the integrity of the various HSDRRS measures and other similar flood protection infrastructure. In this regard, Dr. Losonsky has represented to the Council that, as a former SLFPA-E Commissioner, he does not believe that siting and operating NOPS as ENO has proposed would create any risk of damage to flood protection infrastructure.[466] But Dr. Losonsky relies on more than just the experience that qualifies him as an expert to substantiate this opinion; the scientific analyses he performed also support this conclusion. As Dr. Losonsky testified, "my analyses and calculations provide ample support for my independent, professional opinion that the proposed construction and operation of either the CT unit or the Alternative Peaker **poses no risk** to the integrity of the HSDRRS flood protection components, or any other infrastructure in New Orleans East or the New Orleans Metro area."[467]

2. Intervenors presented no evidence specific to NOPS to demonstrate any risk of groundwater usage or to dispute the validity of Dr. Losonsky's conclusions.

No party presented evidence of any risks associated with the specific groundwater usage required to operate NOPS. Similarly, no party presented any scientifically-based challenges to the calculations Dr. Losonsky performed to prove that NOPS will not increase subsidence and that NOPS poses no risk to area infrastructure, including the flood protection measures that Dr. Losonsky helped to design and implement as a Commissioner of the SLFPA-E.

465 *See* ENO Exhibit Losonsky-1 (Losonsky Supplemental and Amending Direct) at 4-5, 23.

466 *See* ENO Exhibit Losonsky-2 (Losonsky Rebuttal) at 19.

467 *Id*. (emphasis added).

In an attempt to substantiate the allegations that they have raised related to subsidence, Joint Intervenors presented the testimony of Alexander Kolker, Ph.D. Dr. Kolker holds a Ph.D. in "Marine and Atmospheric Science;" he does not have any degrees in geology or hydrogeology.[468] Several of Dr. Kolker's admissions and omissions demonstrate that he has no basis for disputing the accuracy of Dr. Losonsky's calculations and the resulting conclusions. Dr. Kolker states that the opinions he offers in this case are "based on my years of experience."[469] Yet, he has admitted that, prior to this proceeding, he has never before attempted to assess potential impacts of groundwater withdrawal, or to assess possible subsidence risks, related to an industrial facility.[470] Dr. Kolker admitted that, unlike Dr. Losonsky, he did not perform any drawdown[471] or consolidation calculations[472] to attempt to assess the possible impacts of groundwater withdrawal for NOPS. Dr. Kolker further admitted that he made no attempt to replicate the calculations Dr. Losonsky performed or verify the accuracy of the results.[473] Moreover, Dr. Kolker did not, and could not, dispute that the methods Dr. Losonsky employed to assess possible impacts of groundwater usage associated with NOPS have been accepted in the scientific community for decades. As such, the Joint Intervenors have presented no basis for disputing the accuracy or appropriateness of the calculations that provide scientifically-valid evidence to support Dr. Losonsky's conclusions that NOPS will not increase subsidence or pose a risk to area infrastructure.

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468 *See* Joint Intervenors Exhibit Kolker-1 (Kolker Direct) at Exhibit AK-1.

469 *See* Joint Intervenors Exhibit Kolker-2 (Kolker Supplemental Direct) at 1.

470 Tr. (Kolker) 12/20/17, at 139-40.

471 *Id.* at 144.

472 *Id.* at 145-46.

473 *Id.* at 153.

The only specific criticisms Dr. Kolker attempted to levy against the calculations underlying Dr. Losonsky's independent, professional assessment of groundwater usage impacts are demonstrably false. First, Dr. Kolker stated that Dr. Losonsky's calculations only covered a 10-year period, rather than the "entire expected lifetime of the plant."[474] As noted above, Dr. Losonsky's calculations assume, and calculate the worst-case potential effects of, continuous pumping during every hour of every year for a 50 year time period.[475] Next, Dr. Kolker claims that Dr. Losonsky's calculations do not answer the question of "what happens to the void space left behind" after water is withdrawn for operation of NOPS.[476] The assertion that this question "remains unanswered"[477] demonstrates Dr. Kolker's fundamental lack of understanding of aquifer hydraulics as well as the purpose of drawdown and consolidation calculations, which hydrogeologists "have been successfully using analytical solutions to predict the hydraulics of aquifer response to pumping since the 1930's."[478] By taking into account the specific replenishment rate of the New Orleans-Gonzales aquifer, along with other factors detailed in ENO Exhibits JEL-6 and GL-2, the calculations Dr. Losonsky performed serve the precise purpose of answering the question of whether groundwater pumping will create any "void space" at all. In the case of NOPS, "[t]he answer is that no 'void space' will be created in the first place, and [Dr. Losonsky's] calculations provide a mathematically and scientifically sound basis for this conclusion."[479]

Beyond these limited, and erroneous, attempts to cast doubt on Dr. Losonsky's analyses,

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474 *See* Joint Intervenors Exhibit Kolker-2 (Kolker Supplemental Direct) at 5.

475 *See* ENO Exhibit Losonsky-2 (Losonsky Rebuttal) at 7-11.

476 Joint Intervenors Exhibit Kolker-2 (Kolker Supplemental Direct) at 4.

477 *Id.*

478 *See* ENO Exhibit Losonsky-1 (Losonsky Supplemental and Amending Direct) at Exhibit GL-2, p. 3.

479 *See* ENO Exhibit Losonsky-2 (Losonsky Rebuttal) at 11.

Dr. Kolker's discussion of subsidence focused on his recommendation that the Council obtain another opinion on subsidence risks beyond what Dr. Losonsky has provided to the Council. Dr. Kolker first made this recommendation on January 6, 2017, stating that his recommended analysis would include "geotechnical data, geotechnical models, seismic surveys, soil borings, well logs, and storm surge models and climate projections."[480] Dr. Losonsky provided the Council with precisely this level of detail in his analyses[481] and went above and beyond Dr. Kolker's recommendation by performing calculations to predict the worst-case scenarios for possible impacts of groundwater usage that may be required to operate NOPS. Dr. Kolker's response to Dr. Losonsky's analyses, in his October 13, 2017 testimony, was to express the above-described "concerns," which only serve to demonstrate Dr. Kolker's lack of understanding of the substance thereof, and to again recommend that the Council commission additional analyses before making a decision. However, despite frequently expressing his opinion of the importance of the Council obtaining the extra analyses he recommends, Dr. Kolker admitted that he has not performed these analyses during the year that he has been involved in this proceeding.[482]

Dr. Kolker's failure to provide the Council with the analyses he claims are "critical" after more than a year tends to show that his recommendations are born out of a desire to further delay this proceeding and the important decision the Council must make rather than any legitimate concerns. Indeed, neither Dr. Kolker, nor any other Joint Intervenors witness, has provided **any** evidence or analysis specific to NOPS that in any way substantiates the claims that NOPS poses

480 *See* Joint Intervenors Exhibit Kolker-1 (Kolker Direct) at 10.

481 *See* ENO Exhibit Losonsky-1 (Losonsky Supplemental and Amending Direct) at 29 ("[T]he analysis undertaken for the C-K Technical Report was based on geotechnical data, hydrogeological data, soil boring logs, well construction logs, the [Coastal Protection and Restoration Authority] master plan, and other reports that considered storm surge models and climate projections.").

482 Tr. (Kolker) 12/20/17, at 157.

a subsidence-related risk to New Orleans. In contrast, Dr. Losonsky's undisputed, scientifically-valid calculations affirmatively demonstrate that no such risk exists, even in a worst-case scenario. The evidence in the record documents the very real risks that will face the citizens of New Orleans if NOPS is not approved; the evidence also shows that there is **no risk** of NOPS increasing subsidence or causing subsidence-related damage to area infrastructure, including the HSDRRS, if it is approved.

3. Independent and unrefuted analyses confirm that siting NOPS in the location proposed by the Company would not subject the unit to undue flood risks.

Evidence in the record from multiple witnesses and independent third parties demonstrates that siting NOPS as ENO has proposed would not subject the unit to undue flood risks. As ENO witness Mr. Jonathan Long first noted in his November 2016 Supplemental Direct Testimony, design elevations for the proposed site and improvements to area flood protection infrastructure, including the HSDRRS, serve to mitigate the factors that caused the site to experience flooding due to overtopping of levees during Hurricane Katrina.[483] As a result of these improvements, the proposed NOPS site is extremely well-protected against the flood risks that affect the entire Gulf Coast Region, as well as New Orleans specifically. These protections and the resulting mitigated flood risk, along with many other factors, make the proposed site an ideal location for critical storm-response infrastructure like NOPS.

a. Improvements to area infrastructure offer more than adequate protection for the NOPS site.

Mr. Jonathan Long described the well-documented factors that contributed to overtopping of the levees at the Michoud Site in 2005.[484] Mr. Long also described the

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483 *See* ENO Exhibit J. Long-3 (J. Long Supplemental Direct) at 19-20.

484 *Id*. ("As has been well documented, the storm surge that impacted the majority of New Orleans East during Hurricane Katrina resulted from the storm coming through the Gulf of Mexico, creating a record storm surge from

components of the HSDRRS that address each of those factors, including (i) the decommissioning and damming of the MRGO, (ii) the installation of the world's largest surge barrier, the Lake Borgne Surge Barrier, (iii) the construction of the St. Bernard Parish levee floodwalls on either side of the Lake Borgne Surge Barrier, and (iv) the completion of the Seabrook Floodgate on Lake Pontchartrain.[485] These multibillion-dollar flood protection measures literally surround the proposed NOPS site.[486] As Dr. Losonsky describes in further detail, the combination of these improvements contributed to the Coastal Protection and Restoration Authority's ("CPRA") 2017 Master Plan **predicting no flooding** at the proposed NOPS site under the worst case storm scenario modeled for the Plan during the 50 year assumed life of NOPS.[487] In deriving this prediction, the CPRA took into account not only the improved flood protection measures that surround the NOPS site, but also projected sea level rise, projected subsidence, and hundreds of storm models.[488] The Council should note that the CPRA is an independent agency created by the State of Louisiana in 2005 to oversee all coastal restoration and flood protection efforts in the State.[489]

Joint Intervenors made no attempt to refute the CPRA 2017 Master Plan's assessment of flood risks, or the lack thereof, for the NOPS site during the assumed life of the plant. In his Direct Testimony, Dr. Kolker extensively discussed the CPRA's *2012* Master Plan and based his

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the east off of Lake Borgne, and pushing water up the Mississippi River Gulf Outlet ("MRGO") and into the Gulf Intracoastal Waterway ("GIWW"). A storm surge from Lake Pontchartrain also caused water to enter the GIWW from the north, via the Inner Harbor Navigational Canal ("IHNC"). The Michoud site is located along the GIWW, just west of where the MRGO meets the GIWW. The flooding at the Michoud site occurred due to the increased water level in the GIWW, which caused water to overtop the levees protecting the plant.").

485 *Id.* at 20-21.

486 *See id.* at 22; Exhibit JEL-9.

487 *See* ENO Exhibit Losonsky-2 (Losonsky Rebuttal) at 11.

488 *See* ENO Exhibit Losonsky-1 (Losonsky Direct) at 24-25, 28.

489 *See* http://coastal.la.gov/about/structure/.

cautionary recommendations related to flood risks primarily on that outdated version of the Plan.[490] However, as Dr. Losonsky pointed out, the 2012 Master Plan did not take

into account the HSDRRS measures and other improvements to area flood protection infrastructure implemented since its publication.[491] Dr. Losonsky also noted that "[t]he 2017 Master Plan takes these improvements into account and, as a result, **<u>predicts</u> <u>no</u> <u>flooding</u>** in the same scenario described in Dr. Kolker's testimony."[492] In his Supplemental Testimony, Dr. Kolker offered no rebuttal to this point, or any defense to multiple criticisms of the inaccurate and outdated assumptions underlying his flood risk opinions. Ultimately, Dr. Kolker agreed that the "post-Katrina flood protection systems are substantially better than the pre-Katrina ones."[493] Unrefuted evidence in the record from Dr. Losonsky, Mr. Jonathan Long, and the CPRA thus demonstrates that the NOPS site is extremely well protected from the flood risks that affect all of New Orleans.

b. Site design measures for the NOPS location provide additional mitigation to flood risks and exceed FEMA requirements and recommendations.

In addition to the protections offered by the HSDRRS, the NOPS Project Team also took additional steps in the design and planning for NOPS to minimize the risk of NOPS being impacted by flooding. Although the Joint Intervenors questioned some of ENO's witnesses about Council Ordinance No. 26906, which was adopted on May 5, 2016, and amended and re-

490 *See* Joint Intervenors Exhibit Kolker-1 (Kolker Direct) at 7-9.

491 *See* ENO Exhibit Losonsky-1 (Losonsky Direct) at 24-25.

492 *Id*. at 25 (emphasis added).

493 Tr. (Kolker) 12/20/17, at 162-63.

ordained Sections 78-1 through 78-139 of the Code of the City of New Orleans ("Code"),[494] that ordinance confirms that ENO has taken reasonable, prudent steps to address potential flood risks.

Section 78 of the Code is entitled "Floods," and the stated principal purpose of the regulations of that section is to "prescribe minimum requirements for land use and control measures for flood prone areas in the city, as determined by FEMA."[495] Those regulations generally require that the minimum elevation of the lowest floor of new non-residential construction be one foot above Base Flood Elevation ("BFE").[496] The use of BFE as an elevation standard was part of Section 78 before Ordinance No. 26906 was adopted in 2016, and, as Mr. Jonathan Long testified, the Company used a Top of Concrete ("TOC") elevation in its design plans for NOPS that exceeds FEMA guidance for the Michoud Site.[497] More specifically, to determine a TOC elevation that would mitigate the risk of NOPS's being impacted by the type of flooding that was experienced during Hurricane Katrina, the Company commissioned a site survey of the Michoud Site in October 2015 and considered two cases or scenarios when determining the TOC elevation.[498]

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494 *See* Tr. (Jonathan Long) 12/18/17, at 88-89; Tr. (Losonsky) 12/19/17, at 87-90; Tr. (Lovorn-Marriage) 12/20/17, at 31.

495 New Orleans City Code § 78-53(a).

496 New Orleans City Code § 78-81(a). Section 78-81(a) states an alternative elevation of "three (3) feet above the highest adjacent curb (in the absence of curbing, three (3) feet above the crown of the highest adjacent roadway), whichever is higher." A "roadway" under the Code is generally a publicly maintained street or highway that that is open to the use of the public for the purpose of vehicular travel. *See, e.g.*, New Orleans City Code § 154-2 (providing definitions for "highway," "roadway," and "private road or driveway"). Thus, although Mr. Jonathan Long was asked at the hearing about "roadways on the Michoud Site," it is clear from his testimony that he was referring to private roads or driveways within the Michoud property and not to a public roadway. *See* ENO Exhibit J. Long-2 (J. Long Direct) at Exhibit JEL-1 (indicating the proposed CT location on the Michoud Site and distance from any public roadway); and ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 9 (indicating the proposed RICE location on the Michoud Site and distance from any public roadway).

497 Tr. (J. Long) 12/18/17, at 87.

498 *See* ENO Exhibit J. Long-3 (J. Long Supplemental Direct) at 17.

First, the Company considered an advisory BFE from FEMA for the proposed location of the CT, which suggested a TOC elevation for NOPS of 1.0 foot above sea level.[499] Second, the Company focused on the highest point of elevation identified in the October 2015 site survey (the existing Administration Building); considered the 6 to 8 inch flood depth at that building after Hurricane Katrina and rounded up to a flood depth of 1.0 foot; and then used a height of 1 foot above this flood depth to calculate the TOC elevation.[500] This second case resulted in a TOC elevation for NOPS at 3.5 feet above sea level, which is 2.5 feet higher than the FEMA advisory recommendation.[501] The Company opted to use the second case and incorporated a TOC elevation level of 3.5 feet above sea level into the design plans for the CT and RICE options.[502]

The TOC elevation of 3.5 feet above sea level more than complies with Ordinance No. 26906. Indeed, FEMA Flood Insurance Rate Map 22071C0143F, which is adopted and incorporated by reference in Section 78 of the Code,[503] shows a BFE of zero in the zone AE area where ENO proposes to construct NOPS. Furthermore, Section 78 includes a permit-application process that addresses the standards set forth in that section. The Company and its EPC contractor will comply with that process; as Mr. Rice testified at the hearing, ENO will comply with all local regulations in the construction of NOPS.[504] Accordingly, the record evidence

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499 *Id.* at 17-18.

500 *Id.* at 18.

501 *Id.*

502 *Id.*; Tr. (Jonathan Long) 12/18/17, at 86.

503 *See* National Flood Insurance Program Flood Insurance Rate Map, City of New Orleans and Orleans Parish, Louisiana, Panel 143 of 360, Map Number 22071C0143F, available at: https://map1.msc.fema.gov/idms/IntraView.cgi?KEY=76715738&IFIT=1. *See also* New Orleans City Code §§ 78-53(b), 78-58.

504 Tr. (Rice) 12/20/17, at 93-94.

contains no reason to doubt that ENO and its EPC contractor will comply fully with Section 78 upon the issuance of full notice to proceed with the construction of NOPS.

The Joint Intervenors also questioned several ENO witnesses about whether NOPS would be located in a "critical flood zone," but they presented no evidence regarding such a designation.[505] Although the Joint Intervenors appear to be mixing different designations by FEMA, there is no basis in the record to question whether NOPS would comply with advisories from FEMA. Indeed, it is undisputed that ENO's design plans for NOPS exceed FEMA's guidance for the Michoud Site.[506]

Ultimately, the improvements planned for the Michoud Site will raise the elevation of the proposed location of the NOPS units by 5.5 feet.[507] Yet, the limited analysis provided by Dr. Kolker did not take this significant elevation change into account when attempting to assess flood risks for the site. In his Direct Testimony, Dr. Kolker attempted to make predictions of flooding possibilities at the site in various rainfall scenarios.[508] Dr. Losonsky pointed out in his Direct Testimony that Dr. Kolker's predictions did not appear to be granular enough to provide site-specific risk evaluations for the NOPS site and did not appear to have taken into account the elevation change discussed in Mr. Long's testimony.[509] In his Supplemental Testimony, Dr. Kolker failed to rebut this point or rehabilitate any of the numerous flaws Dr. Losonsky illuminated about his flood-risk opinions. Moreover, Dr. Kolker admitted when questioned by the Advisors that his assessment of flood risks at the NOPS site "assumed current conditions at

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505 *See* Tr. (C. Long) 12/15/17, at 199; Tr. (J. Long) 12/18/17, at 71; Tr. (Losonsky) 12/19/17, at 83.

506 ENO Exhibit J. Long-3 (J. Long Supplemental Direct) at 18; Tr. (J. Long) 12/18/17, at 87.

507 *See* ENO Exhibit J. Long-3 (J. Long Supplemental Direct) at 17-18. ("The October 2015 survey indicates that the elevation at the proposed location of the CT is 2.0 feet below sea level.").

508 *See* Joint Intervenors Exhibit Kolker-1 (Kolker Direct) at 7-10.

509 *See* ENO Exhibit Losonsky-1 (Losonsky Direct) at 26-27.

the time of the study" and did not take into account the proposed elevation changes described in detail in testimony.[510] The fact that Dr. Kolker admits to overlooking a difference of 5.5 feet in elevation in assessing flood risks for the NOPS site renders his opinions irrelevant and unreliable. Moreover, Dr. Kolker admitted that he has never previously attempted to assess possible flood risks associated with a proposed industrial facility.[511]

Unlike Dr. Kolker, Dr. Losonsky's analyses did take into account the elevation changes proposed for the NOPS site, as well as the CPRA's prediction of no flooding at the site during the 50-year assumed life of NOPS, even in the worst case scenarios modeled in the 2017 Master Plan. These factors, and other issues detailed in his testimonies, led Dr. Losonsky to attest to the Council that he did not, "as a former Commissioner of the SLFPA-E, believe the Council should be concerned with a risk of flooding at the proposed NOPS site when deciding the merits of ENO's Supplemental Application."[512] Simply put, ample evidence in the record demonstrates that constructing NOPS at the Michoud Site will not result in any undue risk of damage to the unit due to flooding. The Council should reject the Joint Intervenors' apparent position that general flood risks in Orleans Parish make it inappropriate to construct a new power plant, or presumably any other critical infrastructure, in the City.[513]

c. The Company's insurance underwriters agree that the site faces minimal risk of flooding.

The Company's Risk & Insurance Management ("RIM") group arranged a tour for the Company's insurance underwriters and underwriters' engineers of the proposed NOPS site and the HSDRRS to allow them to evaluate the risk of issuing insurance for NOPS and to

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510 Tr. (Kolker) 12/20/17, at 164-65.

511 *Id.* at 141.

512 *See* ENO Exhibit Losonsky-2 (Losonsky Rebuttal) at 19.

513 Notably, Joint Intervenors do not seem to express concerns about flood risks when considering the hypothetical installation of 100MW of solar resources at the NOPS site.

demonstrate to the group that hurricane and storm damage risk associated with ENO's portfolio of assets had been greatly reduced by the installation of the HSDRRS system.[514] During the tour, special emphasis was placed on the improvements to the levees, floodwalls, gated structures, and pump stations that form the 133-mile Greater New Orleans perimeter system, in addition to the improvements to the approximately 70 miles of interior risk reduction structures.[515] Upon completion of the site visit and tour of the HSDRRS, the insurance underwriters conveyed to the Company's RIM group that, not only were they much more comfortable with insuring ENO's portfolio of assets, but they also felt that any flood risks to NOPS would be minimal given the HSDRRS and the fact that TOC elevation would be 3.5 feet above sea level.[516]

C. The air emissions from NOPS will comply with all applicable state and federal environmental regulations, which regulations are designed to be protective of human health, including sensitive populations.

1. Overview of NOPS Air Emissions Issues

Joint Intervenors have raised objections to NOPS on the ground that it will have air emissions as a result of burning natural gas to generate electricity. They have solicited some community opposition to NOPS by telling residents that the plant will be unsafe or will have an adverse effect on their health. However, Joint Intervenors' claims of the parade of horribles that allegedly will be visited upon the residents of New Orleans East if NOPS is approved are not supported by evidence and do not withstand even cursory scrutiny.

In fact, as discussed in more detail below, the evidence clearly shows that NOPS will be safe in every respect. First, ENO must submit an application to the Louisiana Department of Environmental Quality ("LDEQ"), and the LDEQ will perform an intense review of that

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514 ENO Exhibit J. Long-3 (J. Long Supplemental Direct) at 18-19.

515 *Id.* at 19.

516 *Id.*

application to ensure that the plant complies with all state and federal environmental standards and regulations and to ensure that the plant will be operated safely without adverse health effects to the community.

Additionally, the permitted emissions of the plant will be significantly less than the permitted emissions of the natural gas plant that operated at that same site for over 50 years. Finally, air dispersion modelling performed in this proceeding by experts clearly demonstrates that there will be no adverse health effects on the surrounding community as a result of air emissions from the new facility. Thus, as opposed to the parade of horribles suggested by Joint Intervenors, the real effect on the community resulting from the Council's approval of NOPS will be the economic shot in the arm that comes from investing over $200 million in Orleans Parish to construct a modern, efficient source of local peaking generation that will create jobs, improve transmission grid reliability, help prevent cascading outages, and assist with hurricane restoration. In sum, Joint Intervenors' histrionic warnings notwithstanding, ENO will construct and operate NOPS safely and in accordance with all applicable state and federal environmental regulations and without any adverse effects on the health of Orleans Parish residents or anyone else.

2. ENO must obtain authorization from the Louisiana Department of Environmental Quality prior to constructing and operating NOPS.

Article IX, § 1 of the Louisiana Constitution of 1974 provides that "[t]he natural resources of the state, including air and water . . . shall be protected, conserved, and replenished insofar as possible and consistent with the health, safety, and welfare of the people." Pursuant to the Louisiana Environmental Quality Act of 1979, as amended, the Louisiana Department of Environmental Quality ("LDEQ") has been designated as the "primary agency in the state concerned with environmental protection and regulation." La. Rev. Stat. § 30:2011 (2016). The

LDEQ has jurisdiction over matters affecting the regulation of the environment within the state, including, but not limited to, the regulation of air quality. *Id.*

The LDEQ is also charged with ensuring compliance with federal environmental legislation enacted by Congress and with federal standards and regulations interpreting and implementing that legislation that are established the Environmental Protection Agency ("EPA"). La. Rev. Stat. § 30:2011 D(2) (2016). The federal EPA was first established in 1970, and its mission is to "protect human health and the environment." When Congress enacts environmental legislation, such as the federal Clean Air Act of 1970 and subsequent amendments thereto ("CAA"),[517] the EPA is responsible for implementing that law by writing regulations and establishing federal standards that states help enforce through their own regulations and state implementation plans.

With regard to NOPS, under the requirements of the CAA, as amended, ENO must obtain a Title I preconstruction permit from the LDEQ before construction can begin, and must obtain a modification to the existing Michoud Plant Title V operating permit before the plant can be operated.[518] The LDEQ air permitting procedures combine these preconstruction and operating permitting programs under a single permit application, review and issuance process, which ENO must complete prior to beginning construction.[519] LDEQ will review ENO's application submittal to assure that no adverse air quality impacts would result from the project, and to identify all applicable state and federal regulations and standards for the proposed equipment.[520] When the permitting review procedures are complete, including any associated public or EPA

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517 U.S.C. § 7401, *et seq.*

518 ENO Exhibit Higgins-1 (Higgins Supplemental and Amending Direct) at 16.

519 *Id.*

520 *Id.* at 21.

review and comment periods on the draft permit and application materials, LDEQ would take final action on the Title V permit modification request.[521] A final permit to modify the Title V permit would also include LDEQ authorization to construct the NOPS.[522] Thus, before ENO can even begin construction of NOPS, the LDEQ— the state agency statutorily authorized and constitutionally entrusted with the task— will perform the preconstruction review and the review of all state and federal air quality requirements that will apply to operation of the facility.[523]

3. *Permitted emissions for each NOPS alternative will be significantly below permitted emissions for the former Michoud units.*

As ENO's air emissions and permitting expert witness, Ms. Bliss M. Higgins, testified,[524] each NOPS alternative will result in substantial decreases in permitted (allowable) emissions as compared to the currently permitted Michoud Power Plant. The tables below present the "Before" and "After" permitted emissions for each alternative, based on available project information at the time Ms. Higgins's testimony was filed, and clearly show that the anticipated permitted emissions for each pollutant for the NOPS alternatives are at least 48% below the corresponding permitted emissions for the former Michoud units, and in several cases are over 95% lower than those permitted emissions.[525] Moreover, the *only* pollutant that the Joint Intervenors addressed in testimony is particulate matter smaller than 2.5 microns in diameter ("$PM_{2.5}$"), and the tables below clearly show that permitted emissions of $PM_{2.5}$ for the NOPS CT and for the NOPS RICE units are, respectively, 95% less than and 65% less than the permitted emissions of $PM_{2.5}$ for the former Michoud units.

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521 *Id.*

522 *Id.*

523 *Id.*

524 *Id.* at 17-19.

525 *Id.*

Table 1
Comparison of "Before" and "After" Permitted Emission Rates
NOPS Alternative 1, 226 MW CT Project

Pollutant	"Before" Currently Permitted Michoud Power Plant Emissions (tons per year)	"After" Anticipated Permitted NOPS Emissions[526] 226 MW CT Project (tons per year)	Change in Permitted Emissions (tons per year)	Percent Reduction (%)
PM_{10}	283.55	13.82	-269.73	95.1%
$PM_{2.5}$	283.55	13.82	-269.73	95.1%
SO_2	22.55	7.26	-15.79	67.8%
NO_x	8,596.89	273.12	-8,323.77	96.8%
CO	3,132.53	657.04	-2,475.49	79.0%
VOC	205.35	102.82	-102.53	49.9%

Table 2
Comparison of "Before" and "After" Permitted Emission Rates
NOPS Alternative 2, 128 MW RICE Project

Pollutant	"Before" Currently Permitted Michoud Power Plant Emissions (tons per year)	"After" Anticipated Permitted NOPS Emissions[527] 128 MW RICE Project (tons per year)	Change in Permitted Emissions (tons per year)	Percent Reduction
PM_{10}	283.55	97.61	-185.94	65.6%
$PM_{2.5}$	283.55	97.61	-185.94	65.6%
SO_2	22.55	2.87	-19.68	87.3%

[526] Values in this column were based on LDEQ proposed Permit No. 2140-00014-V5, Activity No. PER20160002, EDMS Document No. 10454574, retrieved June 20, 2017. ENO subsequently submitted a new permit application to LDEQ on August 21, 2017, LDEQ TEMPO Activity Nos. PER20170007 and PER20170008, available on EDMS. The "After" values in that application for the CT were revised slightly from those shown here to reflect updated project information. The updated values shown in that application were as follows: PM_{10} and $PM_{2.5}$, 13.94 each; SO_2, 7.22; NO_x, 275.01; CO, 658.55; and VOC, 102.52.

[527] Values in this column were based on preliminary emissions calculations available in June 2017 prior to the filing of ENO's Supplemental and Amending Application. ENO subsequently submitted a new permit application to LDEQ on August 21, 2017, LDEQ TEMPO Activity Nos. PER20170007 and PER20170008, available on EDMS. The "After" values in that application for the RICE units were revised slightly from those shown here to reflect updated project information. The updated values shown in that application were as follows: PM_{10} and $PM_{2.5}$, 78.62 each; SO_2, 3.43; NO_x, 56.92; CO, 100.02; and VOC, 104.56.

NO_x	8,596.89	50.39	-8,546.50	99.4%
CO	3,132.53	89.31	-3,043.22	97.1%
VOC	205.35	105.38	-99.97	48.7%

4. LDEQ's Preconstruction Review and Title V Operating Permit Review

Under the federal CAA, EPA sets National Ambient Air Quality Standards ("NAAQS") for pollutants of concern, and each state is required to implement a plan for attaining and maintaining compliance with the NAAQS for all regions of the state.[528] The CAA also establishes a preconstruction permitting program, called New Source Review, by which state permitting authorities review proposed new stationary sources and proposed modifications to existing stationary sources prior to commencement of construction, to assist in meeting the NAAQS and protecting air quality.[529] New Source Review is composed of two separate but related programs – one that applies if the area where the project would be located has not yet attained air quality that meets the NAAQS (called "nonattainment areas"), and one that applies if the area where the project would be located is in attainment with the NAAQS (called "attainment areas").[530] The same project can be subject to both programs for different pollutants, if the area has a different attainment status for different NAAQS.[531] Because Orleans Parish is in attainment with all of the NAAQS, meaning the air quality in the parish meets all federal air quality standards, only the New Source Review program for attainment areas would apply to the NOPS alternatives.[532]

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528 ENO Exhibit Higgins-1 (Higgins Supplemental and Amending Direct) at 21-22.

529 *Id.*

530 *Id.*

531 *Id.*

532 *Id.*

The New Source Review preconstruction permitting program is referred to as the Prevention of Significant Deterioration program ("PSD") and is designed to help ensure that states maintain compliance with these federal air quality standards and prevent any significant deterioration of air quality in attainment areas.[533] To accomplish this goal, the PSD program requires permit applicants for any ***new major stationary source*** or any ***major modification*** to an existing major stationary source to undergo a control technology review and to conduct an air quality analysis to demonstrate that the proposed emissions would not cause or contribute to an exceedance of the NAAQS and would not cause an exceedance of allowable pollution increases, called PSD increments, for the area.[534]

Pursuant to the regulations governing the PSD program, each NOPS alternative would be considered a "minor modification" to an existing stationary source (*i.e.*, the Michoud plant) because the net emissions increase from each of the proposed alternatives, when considered together with other creditable emissions increases and decreases occurring during the contemporaneous period,[535] are below the level of emissions increases that the EPA has determined to be *de minimis* with regard to their potential for adversely impacting air quality.[536]

Because NOPS is considered a "minor modification" and therefore the level of emissions increases are considered *de minimis*,[537] ENO is not required to perform the air quality analysis

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533 *Id.*

534 *Id.*

535 *Id.* at 27. The contemporaneous period is defined as the time period beginning five years before the projected commencement of construction on the proposed project, and ending on the date that the increase in emissions from the proposed project will occur. *Id.*

536 *Id.* at 23; *see also Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)*, EPA, Final Rule, 73 Fed. Reg. 28,332, May 16, 2008.

537 In establishing the significant emission rates, EPA identified a level of emission increase that would be unlikely to cause ambient impacts above the significant impact level for the NAAQS. For example, the original significant emission rate for particulate matter (25 tons per year) was set by EPA using an air quality modeling analysis to determine the level of emissions that would be unlikely to cause ambient impacts above 4 percent of the PM NAAQS. 73 Fed. Reg. 28,332 – 28,333. The NAAQS itself is set at a level protective of public health and the

that would be required for a major modification to obtain a permit. However, even though it was not required by the PSD regulations to perform an air quality analysis, ENO nevertheless retained emissions dispersion modeling experts from C-K and Associates to perform such modeling to further prove that air quality in the surrounding area would not be adversely affected by the operation of NOPS. The results of that modeling are discussed in the next section.

It should be noted that as the permitting authority, the LDEQ is responsible for reviewing the emissions calculations provided by the applicant to assure they are technically sound and correct, and that any emission increases resulting from the modification have been appropriately identified and estimated.[538] In addition, LDEQ assesses and incorporates into the draft permit applicable emission control requirements, emission limitations, work practices, monitoring, recordkeeping and reporting requirements based on the type of equipment or activities proposed and the level of potential emissions from the equipment.[539] Despite the *de minimis* nature of the emission changes, projects that constitute minor modifications are still subject to numerous air quality emission standards and associated monitoring, recordkeeping and reporting requirements.[540] Also, LDEQ establishes specific allowable mass emission rates for individual emission units or groups of emission units through the permitting process, including both short-term (lb/hr) and annual (ton per year) limits.[541] LDEQ also reviews the application with regard to pollutants not addressed by the NAAQS, including federal hazardous air pollutants and

environment, and the potential impacts from a minor modification would be at levels that are only a very small fraction of the NAAQS. ENO Exhibit Higgins-1 (Higgins Supplemental and Amending Direct) at 27-28.

538 ENO Exhibit Higgins-1 (Higgins Supplemental and Amending Direct) at 28-29.

539 *Id.*

540 *Id.*

541 *Id.*

Louisiana toxic air pollutants.[542] Finally, LDEQ may choose to perform air dispersion modeling of the proposed emissions to model predicted ambient concentrations resulting from the proposed facility, and LDEQ has broad authority under LDEQ air permitting regulations to incorporate into the permit any conditions the agency deems reasonable and necessary to protect air quality.[543]

5. *The air quality evaluation performed by C-K Associates further proves that there will be no adverse impacts on air quality from NOPS.*

Because NOPS net emissions increase is below the air standards threshold, LDEQ does not require air dispersion modeling for NOPS to obtain a permit.[544] Nevertheless, because Joint Intervenors had raised concerns about emissions from NOPS, ENO retained C-K Associates Environmental Consultants to perform a voluntary screening level air dispersion model to understand ground-level concentration exposure to the public using conservative assumptions.[545]

Expert environmental consultants[546] with C-K Associates used the EPA-preferred AERSCREEN air dispersion model to perform screening analysis estimates of downwind ambient concentration of air pollutants emitted from both the CT and the RICE NOPS alternatives.[547] The atmospheric dispersion modeling is the mathematical simulation of how air

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542 *Id.*

543 *Id.* (citing La. Administrative Code § 33:III.501.C.6).

544 ENO Exhibit J. Long-3 (J. Long Supplemental Direct) at Exhibit JEL-6, p. 15.

545 *Id.* at Exhibit JEL-6, p. 15.

546 C-K Associates is an engineering firm that has been licensed in the state of Louisiana for over 30 years. The C-K Associates personnel who contributed to the Air Analysis portion of the Report are (i) Mr. Vinh Nguyen, a licensed professional engineer ("P.E.") with 32 years of experience in evaluating air emissions issues and performing air dispersion modeling; and (ii) Ms. Beth Szwec, an environmental scientist with 29 years of experience in air dispersion modeling and air quality risk assessment. These individuals are familiar with environmental regulations, as well as the environmental and air quality matters discussed in the Report. ENO Exhibit ENO-1 (Losonsky Affidavit) at 1-2.

547 ENO Exhibit J. Long-3 (J. Long Supplemental Direct) at Exhibit JEL-6, p. 15.

pollutants disperse in the ambient atmosphere.[548] AERSCREEN is the recommended screening model that will produce conservative impact estimates without the need for hourly meteorological or detailed terrain data.[549] If air quality using AERSCREEN passes the appropriate NAAQS standards, there is no need for additional modeling because AERSCREEN produces estimates of "worst case" concentrations.[550] The AERSCREEN modeling performed for the CT and RICE alternatives revealed that the air emissions for the CT and the RICE units were well below the NAAQS for all modeled pollutants.[551] The conclusions of the C-K Technical Report with regard to air emissions are as follows:[552]

- No new chemicals will be released due to NOPS when compared to historical Michoud plant operations;
- Emissions are consistent with natural gas combustion;
- Emissions are dissipated before they reach the fence line to concentrations much below the limits for public breathing level air (NAAQS); and
- The new NOPS (each alternative) will represent a significant reduction in emissions when compared to previous operations;
- In no case will the emissions cause air ambient concentrations to exceed regulatory standards, which are protective of human health and the environment.

6. *Joint Intervenors' scare tactics regarding NOPS air emissions are contradicted by the evidence.*

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548 *Id.* at Exhibit JEL-6, p. 15.

549 *Id.* at Exhibit JEL-6, p. 15.

550 *Id.* at Exhibit JEL-6, p. 15.

551 *Id.* at Exhibit JEL-6, p. 28; and ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at Exhibit JEL-12, p. 12.

552 ENO Exhibit J. Long-3 (J. Long Supplemental Direct) at Exhibit JEL-6, p. 16-17; and ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at Exhibit JEL-12, p. 3.

From early on in these proceedings, Joint Intervenors have made unsubstantiated allegations and assertions to anyone who would listen (community members, Councilmembers, reporters, etc.) suggesting that the air emissions from NOPS would be harmful to the community in New Orleans East. ENO has submitted evidence from Ms. Higgins, an expert in air emissions and permitting and former LDEQ Assistant Secretary who wrote Louisiana's air toxics regulations, proving that, in fact, no adverse health effects will result from the operation of NOPS. ENO has shown that NOPS, which depending on the alternative chosen, will be either approximately 1/3 (for the CT) or 1/6 (for the RICE units) the size of the former Michoud plant, will have far fewer emissions than the natural gas plant that operated in that same location for the past 50 years and those emissions will be well within the federal NAAQS, which are protective of human health, including sensitive populations.

ENO has further shown that its application to the LDEQ seeking the necessary permits to construct and operate NOPS will receive a thorough and extensive review by the state agency that is best equipped and that is statutorily authorized to conduct such a review. Additionally, ENO has retained air dispersion modeling experts who conducted a conservative air quality screening analysis that clearly shows there will be no adverse health effects as a result of the operation of NOPS.

In contrast to ENO's evidentiary approach to the NOPS air emissions, Joint Intervenors have opted for the emotional approach. Without any specific evidence with regard to NOPS, they have attempted to sow fear in the community despite the fact that their allegations lack any factual or evidentiary support. The only testimony they have submitted on the issue of air emissions addresses only $PM_{2.5}$ emissions[553] and only in a general sense without any attempt to

[553] The only testimony submitted by the Joint Intervenors on this point was by that of Dr. George D. Thurston. The gist of Dr. Thurston's testimony was that there is no scientific consensus with regard to the establishment of a

specifically address NOPS. Joint Intervenors have not submitted any testimony that attempts to refute the C-K Technical Report or the air emissions conclusions contained therein. Neither have Joint Intervenors attempted to conduct their own analysis or air dispersion modeling. One can only conclude that their experts either lack the expertise to do so or that they know that their own analysis would serve only to confirm rather than refute the findings of the C-K experts.

Additionally, Joint Intervenors have not taken exception to ENO's conclusion that NOPS will be considered a minor modification under the PSD program. Rather, at trial, counsel for the Alliance for Affordable Energy appeared to try to get ENO's expert, Ms. Higgins, to concede that the statutory framework established for the PSD program is based on a "regulatory fiction" in that it allows the decrease in currently-permitted emissions from the Michoud plant (with Units 2 and 3 no longer operating) to be netted against the NOPS emissions for the purpose of determining potential effects on air quality from the new facility. Ms. Higgins refused to take the bait:

> **MS. MILLER:** But it is a regulatory fiction created by the permitting rules that since the – essentially the air emissions may have existed since the 1950s, but they have not existed since June 2016. So while it is allowed under the permitting standards, it is a regulatory fiction to determine when the contemporaneous time period will be selected; is that correct?

"no effects threshold" for $PM_{2.5}$. *See* Thurston-1 (Thurston Direct) at 18. In response, ENO's air emissions and permitting expert, Ms. Higgins, pointed out that, "in adopting the current NAAQS for $PM_{2.5}$, the EPA explicitly noted that 'no population threshold, below which it can be concluded with confidence that $PM_{2.5}$-related effects do not occur, can be discerned from the available evidence.'" ENO Exhibit Higgins-2 (Higgins Rebuttal) at 4. Ms. Higgins went on to explain that although a no effects threshold has not been identified to date by the available science, the EPA proceeded to set the NAAQS for $PM_{2.5}$ by evaluating the scientific evidence using a number of different approaches to ascertain possible alternatives for setting the NAAQS, and considering how those alternatives would be protective of public health. *Id.* More specifically, EPA proceeded by characterizing the limitations and uncertainties in the scientific evidence regarding health impacts, and characterizing the range of ambient concentrations for which the Agency has the most confidence in the associations reported in the studies between exposure and health. *Id.* EPA then evaluated the available scientific evidence to identify an ambient concentration "below which uncertainty in a concentration-response relationship substantially increases or is judged to be indicative of an unacceptable degree of uncertainty about the existence of a continuing concentration-response relationship." *Id.* (quoting 78 Fed. Reg. 3097, January 15, 2013).

> **MS. HIGGINS:** No, that's not correct. I couldn't agree with that. There's no regulatory fiction. The regulations are, in fact, the law, and it's not a fiction to consider the emissions that were occurring. It's a real impact on air quality to shut down the units thereby eliminating those emissions and to consider that in the framework of the new project as proposed.[554]

Apparently undeterred by the fact that the law is not a "regulatory fiction," counsel for the Alliance proceeded to suggest through her subsequent question that the Council should simply ignore the legal and regulatory framework established by Congress, the EPA, the Louisiana legislature and the LDEQ and draw its own conclusion regarding air emissions.

> **MS. MILLER:** And the City Council is not required to apply the standard that the LDEQ is applying to consider the emissions of the former Michoud plant in determining what the public interest is with regard to the emissions in the new plant; is that right?[555]

Although the question itself was objectionable (and ENO's counsel's objection to it was sustained), it is worth considering the absurd premise of the Alliance counsel's question. Under the Alliance's apparent view, it would be good public policy for the Council to usurp the role of the LDEQ, disregard the legal and regulatory framework on air emissions that has evolved over the last 40 to 50 years, and ignore the federally imposed air emissions standards that have been developed through a public process over the course of several years and with extensive input from the public and the scientific community, and instead impose its own air emissions standards and regulations without undergoing any process, and to do so in a scientific field in which it lacks both the time and the necessary expertise to develop such standards and regulations. Moreover, presumably the Alliance and the other Joint Intervenors would urge the Council to tell the only Fortune 500 Company headquartered in the City that it cannot invest over $200

554 Tr. (Higgins) 12/19/17, at 57-59.

555 Tr. (Higgins) 12/19/17, at 59.

million in the community to build a modern, efficient peaking generation power plant that ENO's transmission engineers have sworn under oath is needed to prevent cascading outages in the City in the near future, and that such denial could be based on the simple fact that the plant will have emissions associated with burning natural gas to create electricity, even though the air emissions from the new facility will be significantly lower than the previous plant that operated at that same location for 50 years and which emissions changes are, by law, considered *de minimis* such that the public health, including that of sensitive populations, will not be adversely affected. Not only would such an outcome be patently unfair to ENO, but it is simply bad public policy that would send an extremely poor signal to other businesses that might be considering investing in New Orleans by locating operations in the City.

In sum, the Michoud Site is the best and most reasonable site to locate NOPS, and the operation of the NOPS plant will not adversely affect the health of the surrounding community.

D. ENO has conducted extensive public outreach efforts and afforded meaningful opportunity for public participation.

Joint Intervenors witness Dr. Beverly Wright claims that the development of NOPS lacked meaningful public participation.[556] But Mr. Cureington has provided a detailed explanation of the Council's and ENO's multitudinous efforts to engage and inform the public about NOPS.[557] Mr. Cureington begins by detailing the public participation involved in the 2015 IRP process, through which the Council and ENO provided multiple opportunities for

556 Joint Intervenors Exhibit Wright-1 (Wright Direct) at 4; Joint Intervenors Exhibit Wright-2 (Wright Rebuttal) at 2.

557 *See* ENO Exhibit Cureington-8 (Cureington Rebuttal) at 78-90.

meaningful public involvement.[558] During the IRP process, ENO hosted six public technical conferences, two more than initially ordered by the Council, with public notices issued by ENO thirty days before each meeting.[559] ENO responded to feedback it received during these public meetings as it ran additional simulations and incorporated stakeholder feedback into a Stakeholder Input Case that was discussed throughout the Final 2015 IRP and in a supplement to the IRP.[560] The Council provided opportunities for public review and comment on the Final 2015 IRP as well.[561] ENO hosted an additional technical conference followed by a public comment period, the Council held a hearing in its chambers, and Intervenors were given two months to submit comments regarding the IRP.[562]

After its initial NOPS filing in June 2016, the Council and ENO again provided multiple opportunities for public participation.[563] ENO met with community groups, neighborhood associations, and other civic organizations.[564] The Council ordered ENO to file supplemental testimony on environmental issues raised by community members, with which ENO complied;[565] provided an opportunity for Intervenors to file testimony in the docket; ordered ENO to hold two public outreach meetings; and held a hearing in chambers.[566] ENO exceeded the Council's order,

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558 *Id.* at 79.

559 *Id.* at 81-83.

560 *Id.* at 83.

561 *Id.* at 84-85.

562 *Id.* at 84.

563 *Id.* at 87-88.

564 *Id.* at 87.

565 *See* ENO Exhibit J. Long-3 (J. Long Supplemental Direct); ENO Exhibit Cureington-3 (Cureington Supplemental Direct).

566 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 87.

holding four meetings in New Orleans East, with handouts in English, Spanish, and Vietnamese.[567]

As Mr. Cureington has testified, ENO and the Council continued their efforts to encourage public participation after ENO submitted its Supplemental and Amending Application in July 2017.[568] ENO held nine public meetings regarding NOPS, almost double the number of meetings prescribed by the Council, four of which were held in New Orleans East.[569] Handouts for these meetings were available in English, Spanish, and Vietnamese.[570] The Council additionally held a hearing in its chambers that was well-attended and featured a significant amount of community support for NOPS.[571] Altogether, Mr. Cureington testified that ENO has held at least **21** public meetings regarding NOPS, many of which were in New Orleans East.[572] Mr. Rice testified that he believes the number of public meetings is closer to **30**, and that he personally participated in nearly all of those meetings.[573] ENO has clearly made extensive and reasonable efforts to include and inform the public, particularly residents of New Orleans East, about NOPS.[574]

Dr. Wright also has criticized ENO for applying to LDEQ for a minor modification of the existing Michoud air permit because such modifications do not require a public comment period or an Environmental Assessment Statement.[575] But the Company's application to LDEQ was

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567 *Id.* at 88.

568 *Id.* at 89-90.

569 *Id.*

570 *Id.* at 90.

571 *Id.*

572 *Id.*

573 Tr. (Rice) 12/20/17, at 131.

574 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 90.

575 Joint Intervenors Exhibit Wright-1 (Wright Direct) at 16.

entirely proper, and Ms. Higgins has noted that the LDEQ set public hearings in New Orleans East when ENO initially submitted its air permit application—the first was cancelled due to a tornado and the second was cancelled when ENO temporarily suspended its permitting activities.[576] The LDEQ also invited public comments on NOPS (and received several comments in return), and the LDEQ has indicated that it intends to schedule a new public hearing on any draft permits that would authorize the construction and operation of NOPS.[578] Ms. Higgins further advised at the hearing that the LDEQ has requested an Environmental Assessment Statement and that ENO has prepared one in response.[579] Accordingly, the Joint Intervenors' criticisms of LDEQ processes are both improper and incorrect.

E. **Siting NOPS at Michoud does not raise any environmental justice concerns.**

Joint Intervenors witness Dr. Wright has raised the issue of environmental justice and alleged that NOPS would have a racially discriminatory effect on residents living in New Orleans East.[580] Environmental justice is generally a consideration of whether minority and low-income populations are being disproportionately exposed to adverse environmental effects.[581] Although there is no universally accepted definition, Ms. Higgins noted that the EPA defines environmental justice as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies."[582] The EPA further defines "fair treatment" as meaning that "no group of people should bear a disproportionate share of the

576 ENO Exhibit Higgins-2 (Higgins Rebuttal) at 18.

578 *Id.*

579 Tr. (Higgins) 12/19/17, at 77-78.

580 Joint Intervenors Exhibit Wright-1 (Wright Direct) at 4, 22.

581 ENO Exhibit Higgins-2 (Higgins Rebuttal) at 8.

582 *Id.* (quoting Learn About Environmental Justice, United States Environmental Protection Agency, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.).

negative environmental consequences resulting from industrial, governmental and commercial operations or policies."[583] The EPA has provided the following indicators of "meaningful involvement": (1) "[p]eople have an opportunity to participate in decisions about activities that may affect their environment and/or health;" (2) "[t]he public's contribution can influence the regulatory agency's decision;" (3) "[c]ommunity concerns will be considered in the decision making process;" and (4) "[d]ecision makers will seek out and facilitate the involvement of those potentially affected."[584]

The first prong of the EPA's definition of environmental justice concerns fair treatment, or whether minority and low-income groups are disproportionately affected by a particular project. Here, Dr. Wright's criticism stems from her concern for "nearby residential neighborhoods."[585] Dr. Wright testified that there was a distance of 0.75 miles between NOPS and nearby residential neighborhoods;[586] however, Ms. Higgins used the EPA tool EJSCREEN to refute Dr. Wright's claim and show that ***"census data indicate that <u>no</u> people live within a one mile radius of the center of the site."***[587] Mr. Jonathan Long testified that it was "unusual" not to have residential neighborhoods at the fence line of a power facility, which makes the Michoud Site and its one-mile buffer all the more attractive.[588] While this buffer zone does not minimize or eliminate the need to consider potential human health or environmental impacts resulting from the construction and operation of NOPS, the Michoud Site is located in a sparsely populated

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583 *Id.* (quoting Learn About Environmental Justice, United States Environmental Protection Agency, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.).

584 *Id.* (quoting Learn About Environmental Justice, United States Environmental Protection Agency, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.).

585 Joint Intervenors Exhibit Wright-1 (Wright Direct) at 12.

586 *Id.* at 14.

587 ENO Exhibit Higgins-2 (Higgins Rebuttal) at 11 (emphasis added); Exhibit BMH-1.

588 Tr. (J. Long) 12/18/17, at 127.

census tract that does not have the "close geographic proximity to residential neighborhoods" that Dr. Wright suggests in her testimony.[589]

Furthermore, ENO has carefully considered the potential environmental impacts of NOPS. Mr. Rice testified that the Company heard concerns regarding environmental impacts, and that is why ENO hired experts like Ms. Higgins, a recognized expert on environmental regulatory matters,[590] and Dr. Losonsky to look at issues like subsidence and emissions and "ensure that we were not doing anything to harm the community."[591] As discussed above, NOPS is not anticipated to have any adverse effects in the area of air quality, public health, and groundwater withdrawal, and, accordingly, it will not bring negative disproportionate effects to any group of citizens in New Orleans East. To the contrary, NOPS will bring jobs and hundreds of millions of dollars in economic benefits to the City.[592]

The second prong of the EPA's definition concerns meaningful involvement. As discussed above, ENO and the Council held numerous public meetings throughout the 2015 IRP process and throughout the course of this docket, many in New Orleans East where NOPS would be sited. As Mr. Rice has testified, he and his staff have endeavored to keep ENO's customers well informed regarding the Company's plans for NOPS, reaching customers through email and community meetings, nearly all of which Mr. Rice personally attended, thus providing multiple opportunities for meaningful public participation.[593] In setting the procedural schedule in this docket, the Council also has taken several concrete steps to ensure transparency and public input

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[589] ENO Exhibit Higgins-2 (Higgins Rebuttal) at 11 (quoting Joint Intervenors Exhibit Wright-1 (Wright Direct) at 12).

[590] ENO Exhibit Higgins-1 (Higgins Supplemental and Amending Direct) at 12-14.

[591] Tr. (Rice) 12/20/17, at 131-32.

[592] ENO Exhibit Rice-2 (Rice Direct) at 13; Exhibit CLR-2; ENO Exhibit Rice-3 (Rice Supplemental and Amending Direct) at 15-16; ENO Exhibit Rice-4 (Rice Rebuttal) at 18-19; Exhibit CLR-3.

[593] ENO Exhibit Rice-4 (Rice Rebuttal) at 17.

on whether NOPS should move forward.[594] The Council has provided interested parties and the public at large substantial notice and opportunity to be heard concerning the Company's NOPS proposal, including public outreach meetings in each Council district and a public hearing in Council Chambers.[595]

For these reasons, Ms. Higgins concluded that, based on the specific facts and circumstances of the proposed NOPS alternatives, the applicable science, and well-established environmental standards, "the operation of NOPS will not result in any potential environmental injustice."[596] And Mr. Rice addressed head on Dr. Wright's allegations of discrimination and explained how NOPS will have no such effect.[597]

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

The proposed costs for NOPS are just and reasonable, the Company's proposed cost recovery mechanism is both reasonable and essential to bringing the benefits of NOPS to customers, and the Monitoring Plan will help ensure that the Council stays well informed on Project development. As ENO discusses further below, the evidence establishes that (1) NOPS is the lowest reasonable cost alternative to reliably serve ENO's customers; (2) the use of and competitive selection process for the EPC contractors was reasonable; (3) the overall cost for the CT and RICE projects is reasonable; and (4) the Company has put in place reasonable measures regarding project management and construction risk management.

A. The proposed costs for the CT and RICE options are just and reasonable.

1. NOPS is the lowest reasonable cost alternative to reliably serve ENO's customers.

594 *Id.* at 18.

595 *Id.*

596 ENO Exhibit Higgins-2 (Higgins Rebuttal) at 17.

597 ENO Exhibit Rice-4 (Rice Rebuttal) at 20-22.

The Company has demonstrated that NOPS is the lowest reasonable cost alternative to reliably serve ENO's customers and meet the Company's supply needs. As explained in the Direct Testimony of Mr. Cureington, the 2015 IRP portfolio reflected a robust process that identified a CT as the lowest reasonable cost resource addition (considering the risks) capable of meeting the Company's overall capacity needs.[598] Mr. Cureington also explained in his Direct Testimony,[599] Supplemental Direct Testimony,[600] and Supplemental and Amending Direct Testimony,[601] that the Company performed several iterations of economic analyses associated with the CT that it has proposed, and it proved to be the lowest cost option in each. As discussed above, the Company maintains that the proposed NOPS CT remains the best option for customers.

But the Alternative Peaker is a reasonable alternative to the CT.[602] As explained previously, WorleyParsons conducted a technology assessment that determined the RICE units had the lowest levelized cost of electricity among smaller resource options.[603] The Alternative Peaker additionally has other important benefits such as black-start capability, low water usage, a low emissions profile, and the ability to support renewable resources.[604] In terms of cost, the Alternative Peaker is in a virtual tie with the transmission-only case, but, as explained above, the transmission upgrades may not be constructible, would not provide the reliability benefits needed by New Orleans, and would not meet the identified need for a local source of peaking and

598 ENO Exhibit Cureington-2 (Cureington Direct) at 8-9.

599 *Id.* at 38-41.

600 ENO Exhibit Cureington-4 (Cureington Supplemental Direct) at 5-11.

601 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 26-48.

602 *Id.* at 46.

603 ENO Exhibit J. Long-4 (J. Long Supplemental and Amending Direct) at 6.

604 *Id.*

reserve capacity.[605] The Alternative Peaker would add a local source of dispatchable generation capable of providing real and reactive power and mitigating market and supply-related risks when compared to the transmission-only and solar portfolios (albeit to a lesser degree than the CT), which makes the Alternative Peaker a reasonable alternative to the 226 MW CT and a better option than transmission-only and solar possibilities.[606]

2. The selection process for the largest component of the proposed Project costs, the EPC contracts, was reasonable.

The largest price component of both the CT and RICE options is the EPC contract. For both the CT and RICE options, the contractors have agreed to a fixed price, fixed schedule form of EPC contract.[607] The EPC contracts include costs such as equipment, most notably the proposed technologies; engineering and construction management services; supervisory and administrative staffs at the construction site; craft laborers; construction materials; subcontractors; indirect construction costs; sales taxes; and labor and materials associated with the dedicated start-up and commissioning teams.[608] ENO chose to use an EPC contractor for NOPS because the Company does not have the in-house capability to execute the engineering, procurement, and construction for a substantial undertaking like NOPS.[609] Using an EPC contractor who can perform all of these functions under a single contract is cost-effective and common within the power industry for projects like NOPS.[610] No witness has challenged the reasonableness of using an EPC contractor for NOPS.

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605 ENO Exhibit Cureington-8 (Cureington Rebuttal) at 67-68.

606 ENO Exhibit Cureington-6 (Cureington Supplemental and Amending Direct) at 47.

607 ENO Exhibit J. Long-2 (J. Long Direct) at 4; ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 3.

608 ENO Exhibit J. Long-2 (J. Long Direct) at 11.

609 *Id.* at 20; ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 4.

610 ENO Exhibit J. Long-2 (J. Long Direct) at 20; ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 4.

ENO contracted with Chicago Bridge & Iron, Inc. ("CB&I") to provide EPC services for the CT project.[611] CB&I was chosen as a result of a competitive selection process that began in May of 2015 and was finalized in September of that year.[612] Four contractors participated in that solicitation process;[613] ENO approached at least two other contractors that declined to participate.[614] Mr. Jonathan Long testified that the Company chose which contractors to approach based on its preexisting knowledge and experience in the marketplace; accordingly, the Company solicited bids from contractors that it knew were in the business of building plants like the CT project.[615] Additionally, the Company had confidence that these contractors had the capability to do this job, based on their track records for similar projects.[616]

CB&I was chosen from among the participating contractors because its price was the lowest of the four bidders.[617] Additionally, CB&I had performed well as the EPC contractor on the Ninemile 6 project,[618] which came in roughly 10% under-budget and months ahead of its projected in-service date.[619] Because of its commercially reasonable pricing and its knowledge of Entergy's processes gleaned from working on prior projects, CB&I was the prudent choice.[620]

Burns & McDonnell ("B&M") was chosen to be the EPC contractor for the RICE project.[621] Mr. Jonathan Long testified that he began looking for an EPC contractor shortly after

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611 ENO Exhibit J. Long-2 (J. Long Direct) at 3.

612 Tr. (J. Long) 12/18/17, at 44; ENO Exhibit J. Long-2 (J. Long Direct) at 10.

613 ENO Exhibit J. Long-2 (J. Long Direct) at 10.

614 Tr. (J. Long) 12/18/17, at 45.

615 *Id.*

616 *Id.* at 45-46.

617 ENO Exhibit J. Long-2 (J. Long Direct) at 10.

618 *Id.*

619 *Id.* at 5.

620 *Id.* at 10.

621 ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 15.

the decision was made to suspend the procedural schedule in this docket.[622] He went back to the two top bidders from the previous competitive selection process, CB&I and B&M, to solicit proposals regarding the RICE project.[623] B&M was selected because of its competitive pricing and extensive prior experience constructing units using RICE technology.[624] B&M is the industry leader in RICE projects over 25 MWs, having installed, as of 2015, a total of 72 RICE engines, 60 of which were Wärtsilä engines in projects similar to NOPS.[625]

3. The overall cost estimates for the CT and RICE projects are reasonable.

The overall cost estimate for the CT is $232 million.[626] This estimate includes the EPC contract, other vendors and expenses, Entergy project management, indirect loaders, an Allowance for Funds Used During Construction ("AFUDC"), a project contingency, transmission interconnection to the switchyard, and regulatory costs.[627] The non-EPC costs were developed using internal subject matter experts and third-party providers.[628] As previously discussed, the EPC contract is the largest single cost component.[629] While the overall cost for the CT was originally estimated to be $216 million, the delay in issuing a Notice to Proceed ("NTP") has caused the EPC price to escalate, and there was a change in scope for transmission interconnection.[630] The price escalation provisions in the EPC contract will be discussed in more detail below.

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622 Tr. (J. Long) 12/18/17, at 64.

623 *Id.* at 65-66.

624 ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 15.

625 *Id.* at 15-16.

626 *Id.* at 5.

627 ENO Exhibit J. Long-2 (J. Long Direct) at 10.

628 *Id.* at 6.

629 *Id.* at 10.

630 ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 5.

The overall cost estimate for the RICE units is $210 million.[631] This estimate includes the same cost components as the CT, with the EPC contract composing the largest single cost component.[632] Included in Mr. Jonathan Long's July 2017 testimony is a table that shows an installed cost of $120.3 million for seven Wärtsilä RICE units.[633] That table presented industry data and modeling that was used to compare the RICE units to other technology options; it did not present or include site-specific cost estimates or non-EPC cost estimates.[634] The EPC price of [redacted] negotiated with B&M for the RICE units includes site-specific factors such as foundation design, regional labor rates, and risks assumed by B&M in the EPC agreement.[635] With respect to non-EPC costs, as with the CT, those costs were estimated by internal subject matter experts and include project management and oversight (both internal and external services), inspections and testing, environmental permitting, pursuing regulatory approvals, temporary facilities and supplies, AFUDC, and project contingency.[636]

Mr. Jonathan Long has explained certain escalation and price-renegotiation provisions in the EPC agreements with CB&I and B&M.[637] He testified that EPC agreements routinely employ escalation provisions to account for inflationary pressures should construction not begin on a specified date, and that this practice is "reasonable and standard."[638] He also noted that it was typical of EPC contracts to have a "sunset" date at which pricing is subject to renegotiation

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631 *Id.* at 3.

632 *Id.* at 15.

633 *Id.* at 10.

634 *See id.* at 10 n.3, 11; *see also* Tr. (J. Long) 12/18/17, at 23-26, 109-10.

635 Tr. (J. Long) 12/18/17, at 110. Mr. Long testified at the hearing that the contract with B&M had not been executed but that it would be in place under the terms, conditions, and pricing set forth in his testimony at the time the Council makes a decision in this docket. *See id.* at 66-67.

636 ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 15-16.

637 ENO Exhibit J. Long-2 (J. Long Direct) at 13-14; ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 16-17.

638 ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 4.

if performance has not commenced, as it would not be reasonable to expect that providers of equipment or EPC services could indefinitely guarantee pricing.[639] However, if NTP is issued before the sunset date, the contractors will have no opportunity to renegotiate pricing.[640]

For the CT option, the EPC agreement provides for price escalations if NTP was not issued on or before [redacted].[641] If NTP is not issued by the sunset date of [redacted], the EPC contract price is open to renegotiation.[642] Because the escalation clause date has passed, the costs associated with escalation will be at least $3.1 million.[643] If the sunset date passes, Mr. Jonathan Long testified that he does not currently anticipate that CB&I would seek substantial changes to its pricing, particularly if the Council's decision is made close to the sunset date.[644] If the Council does not approve the CT option, the Company will not issue NTP to CB&I or incur any liability under that EPC agreement, as the services under that agreement do not start until ENO issues NTP.[645]

For the RICE option, the Company has negotiated with B&M an extension of the commencement of price escalation to [redacted].[646] Thus the [redacted] EPC cost estimate set forth in Mr. Jonathan Long's July 2017 testimony will hold through that date.[647] If NTP is not issued by the sunset date of [redacted], the EPC contract price is open to

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639 Tr. (J. Long) 12/18/17, at 36.

640 *Id.* at 128.

641 *See* ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 4.

642 ENO Exhibit J. Long-2 (J. Long Direct) at 13.

643 ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 4-5.

644 Tr. (J. Long) 12/18/17, at 79. Mr. Long further explained why it would not be reasonable to assume that CB&I would attempt to exploit renegotiations if the Council chooses the CT option after the sunset date. *Id.* at 80-81.

645 *Id.* at 52.

646 *Id.* at 76-77.

647 *Id.* at 35-36.

renegotiation.[648] Importantly, none of the witnesses in this case have challenged the reasonableness of the overall cost estimates for the CT and RICE options or the specific provisions of the EPC contracts discussed above.

4. The Company has put in place reasonable measures for project management and construction risk management.

ENO is using the same project management structure for NOPS that was used successfully for the construction of Ninemile 6.[649] Mr. Jonathan Long has explained that this approach follows Entergy's Project Delivery System ("PDS") Policy, Standards and Guidelines to support consistency and certainty in project delivery outcomes.[650] The PDS uses a Stage Gate Process ("SGP") approach to provide a roadmap of key deliverables and decisions that need to be sequentially completed to promote consistent, reliable, and high-quality project outcomes.[651] Additionally, the SGP also prescribes a continuous systematic evaluation of the project organization, scope, and maturity of project management deliverables that helps ensure projects are successfully executed.[652] This occurs through a series of independent Gate Reviews/Assessment and Approvals.[653] The project management team includes team members from the Ninemile 6 project and new team members.[654] Overall oversight for NOPS will be

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648 *Id.* at 77. When Mr. Long filed his July 2017 testimony, the escalation date was [redacted], and the sunset date was [redacted] *See* ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 16-17.

649 ENO Exhibit J. Long-2 (J. Long Direct) at 18-19; *see also* ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 20 (noting that the Company will follow the same project management structure for the RICE as for the CT).

650 ENO Exhibit J. Long-2 (J. Long Direct) at 19.

651 *Id.*

652 *Id.*

653 *Id.*

654 *Id.* at 32.

provided by the Executive Steering Committee.[655] No witness disputes the reasonableness of the Company's project management structure.

Mr. Jonathan Long also explains the measures ENO has put in place to manage and mitigate the potential risks in constructing NOPS,[656] none of which measures have been called into question by any party or witness. More specifically, Mr. Long includes extensive discussion in his testimonies about risks under the EPC contracts and the steps that have been taken to mitigate those risks.[657] The record is undisputed that customers benefit from the Company's using EPC contractors for a Project like NOPS.[658] The fixed-price structure and well-defined scope of work of the EPC contracts are expected to minimize the effect of key risks on project costs.[660] The Company also included a contingency in the project cost estimate that is thought to be reasonably sufficient to mitigate potential risks to the Project.[661] Additionally, the schedule has a built-in contingency for critical path activities that will help mitigate short delays.[662]

Mr. Jonathan Long explained that the contingency, which is approximately 5% of the CT's total estimated project costs[663] and 6% of the Alternative Peaker's total estimated project costs,[664] is not meant to cover all of the uncertain risks that could increase costs.[665] It is intended, instead, to *reasonably* mitigate unplanned increases in project costs, whether caused by known

[655] *Id.* at 33.

[656] *See* ENO Exhibit J. Long-2 (J. Long Direct) at 23-34.

[657] *See id.*; ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 22-28.

[658] ENO Exhibit J. Long-2 (J. Long Direct) at 14-15, 20-21, 28-29; ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 25-26.

[660] *Id.* at 24.

[661] *Id.*

[662] *Id.*

[663] *Id.* at 14.

[664] ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 17.

[665] *Id.* at 23; ENO Exhibit J. Long-2 (J. Long Direct) at 24.

risks or unforeseen risks.[666] To determine what amount of contingency to include in cost estimates, the project team first compiles a register of risks that it identifies related to the development and construction of the project.[667] The team then characterizes each of those risks in terms of probability of occurrence and impact to the project, both in terms of cost and schedule.[668] After the risks have been characterized, the project team puts the risks into a model that uses a Monte Carlo simulation to run iterations of those potential risks.[669] Based on the outcome of the Monte Carlo simulation, the project team selects a contingency level.[670] Mr. Jonathan Long testified that his team selected a confidence interval of P50 in determining the contingency level, meaning that the contingency should be sufficient to cover approximately half of the uncertain risks that are identified through the simulation process.[671] No witness has questioned the reasonableness of ENO's process in determining the contingencies for the CT and RICE options. Furthermore, the Company does not retain or seek to charge customers for unused project contingency.[672]

Finally, the Company intends to procure insurance before issuing the NTP for either the CT or the RICE project.[690] The expected coverage will include Builders All Risk ("BAR") and Delay in Startup ("DSU"). BAR insurance covers property damage to the project work from

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666 ENO Exhibit J. Long-2 (J. Long Direct) at 24.

667 Tr. (J. Long) 12/18/17, at 27-28.

668 *Id.* at 28.

669 *Id.*

670 *Id.*

671 *Id.* at 28-29, 31-32. As Mr. Long explained at the December 2017 Hearing, the use of a P50 confidence interval does not mean that there is a 50% chance of the project's going over budget. *See id.* at 31-33.

672 ENO Exhibit J. Long-2 (J. Long Direct) at 25; Tr. (J. Long) 12/18/17, at 30-31.

690 ENO Exhibit J. Long-2 (J. Long Direct) at 29; ENO Exhibit J. Long-5 (J. Long Supplemental and Amending Direct) at 26.

non-excluded perils while it is under construction,[691] and Mr. Jonathan Long testified that flooding at the site would be one of those named perils.[692] The limit of liability on the BAR insurance is expected to be roughly equal to the EPC contract value, subject to various deductibles depending on the insured peril.[693] DSU insurance covers certain schedule-delay costs resulting from property damage to project work caused by a non-excluded peril under the BAR insurance.[694] After the deductible period is met, DSU insurance provides coverage for certain costs until project completion is achieved, including AFUDC, owner's costs, and contractors increased site costs.[695] No witnesses have challenged the reasonableness of the Company's approach to obtaining insurance.

B. Cost recovery mechanism

1. ENO maintains its request for an exact cost recovery mechanism, but agrees the Advisors' two-step cost recovery proposal would work and could provide a sound mechanism for the recovery of the revenue requirements.

It is indisputable that the principles of sound regulation dictate that ENO has a right to a reasonable opportunity to recover its prudently incurred investment, including a fair return. The Company interprets the proposals made by the Advisors as an attempt to propose recovery mechanisms that comply with these sound regulatory principles. The Advisors' witnesses' (Messrs. Joseph A. Vumbaco and Victor M. Prep) testimony recommends that, should the Council determine NOPS to be in the public interest, ENO should be authorized to include the NOPS-related non-fuel revenue requirement in the upcoming Combined Rate Case through a

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691 ENO Exhibit J. Long-2 (J. Long Direct) at 30.

692 Tr. (J. Long) 12/18/17, at 72-73.

693 ENO Exhibit J. Long-2 (J. Long Direct) at 30.

694 *Id.*

695 *Id.*

pro-forma adjustment that would provide for cost recovery in the form of a "second step" adjustment to base rates that would be implemented in the first full billing month following the unit's Commercial Operation Date ("COD").[696] There are two NOPS Peaker alternatives pending before the Council for consideration. Although the Company respectfully maintains its request for a modified exact cost recovery mechanism to recover the NOPS revenue requirement, the Company agrees that the Advisors' cost recovery proposal could provide a sound mechanism for the recovery of the revenue requirements associated with NOPS.

Overall, it is important to bear in mind that if ENO is to undertake a project on the scale of either NOPS alternative, which would be the first of its kind in over 40 years, ENO must have assurances that it will have a reasonable opportunity to recover its full investment, including its authorized return. Although it is true that there is more than one way to accomplish ratemaking that results in just and reasonable rates, if the proposed recovery mechanism for NOPS does not allow for contemporaneous in-service implementation, regulatory lag on a $211-240 million investment (as part of a roughly $800 million (2016) rate base (equity portion)) will greatly reduce ENO's opportunity to earn its allowed (fair) return on that investment, creating unacceptable financial uncertainty for ENO.[697] Further, as described by Company witnesses Mr. Orlando Todd and Ms. Lovorn-Marriage, for a company of ENO's size, prolonged regulatory lag on recovery of this substantial investment could severely limit ENO's ability to make other required investments and respond to emergency conditions.[698]

2. *The PPCACR Rider would provide the greatest flexibility in meeting the objectives of providing ENO a reasonable opportunity to recover investment in supply-side and resolves any timing issues that may result*

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696 Advisors Exhibit Vumbaco-1 (Vumbaco Direct) at 30; Advisors Exhibit Prep-1 (Prep Direct) at 19-20; Tr. (Prep) 12/21/17, at 139-40.

697 ENO Exhibit Lovorn-Marriage-2 (Lovorn-Marriage Rebuttal) at 5, 12.

698 *Id.* at 5; ENO Exhibit Todd-2 (Todd Supplemental and Amending Direct) at 10.

in regulatory lag, while avoiding the burden and inefficiency of pancaked rate cases.

ENO proposes that the Purchased Power and Capacity Acquisition Cost Recovery PPCACR ("PPCACR") Rider be used to recover the revenue requirement associated with either NOPS alternative. As explained in the testimony of Mr. Todd and Ms. Lovorn-Marriage, due to the level of the investment associated with NOPS, it is imperative that the mechanism used to recover the NOPS revenue requirement is implemented contemporaneous with when the project is placed in service ("in-service recovery").[699] Taking into consideration regulatory and administrative efficiencies, a modified version of the PPCACR Rider could serve as such a mechanism, while adhering to traditional principles of ratemaking, (*e.g.*, matching benefits with burdens and cost causation).[700] In the absence of such a mechanism, the lag incurred on the project will substantially undermine ENO's ability to earn its Council-authorized return and/or, in order to obtain timely recovery, would likely force ENO to file an additional rate case on the heels of the conclusion of the Combined Rate Case that must be filed by July 2018. No party has disputed that well-established ratemaking principles require that ENO have a full and fair opportunity to recover prudently incurred costs of whatever project and level of capital spending the Council might approve. However, the Advisors and Air Products have objected to ENO's proposed method of achieving that objective, *i.e.*, the implementation of an exact recovery rider. The concerns articulated by the Advisors and Air Products are addressed, each in turn below.

3. The Advisors object to ENO's proposed exact recovery rider as single-issue ratemaking, but, if implemented in the context of a Formula Rate Plan, ENO's rider would not violate the principles of single-issue ratemaking. Alternatively, the circumstances warrant an exception.

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699 ENO Exhibit Lovorn-Marriage-2 (Lovorn-Marriage Rebuttal) at 5; ENO Exhibit Todd-1 (Todd Direct) at 8-9; ENO Exhibit Todd-2 (Todd Supplemental and Amending Direct) at 6.

700 ENO Exhibit Lovorn-Marriage-2 (Lovorn-Marriage Rebuttal) at 5.

The Advisors have objected to the implementation of the PPCACR to recover the NOPS-related non-fuel revenue requirement on the basis that it constitutes single-issue ratemaking that is generally impermissible with limited exceptions. In his direct testimony, Mr. Prep indicates that "there is no burden imposed upon ENO in meeting unexpected, volatile or fluctuating expenses that would require an exception to the exemption for single issue rate making. … the Combined Rate Case anticipated to be filed by mid-2018, together with subsequent annual reviews for revenue adjustments (via an FRP [Formula Rate Plan] or full decoupling mechanism), will provide the Council with an examination of total utility fixed costs, including pro-forma adjustments and ratemaking options regarding prospective rates for the cost recovery periods of the NOPS alternatives." (Emphasis added.) The language indicating that annual reviews would be required to provide cost recovery alternatives for NOPS implicitly recognizes that depending on the NOPS alternative approved by the Council, the timing of a decision on the Combined Rate Case and the timing of the placement of the NOPS project in service, under past ratemaking practice before the Council, there would be no certainty that the NOPS-related revenue requirement on an in-service basis as the result of a pro forma adjustment to the Period II test year. As such, it is necessary that ENO have assurances from the Council that it will be permitted to include pro forma(s) of the NOPS project revenue requirement into the case, as has been proposed by Mr. Prep.

To be clear, if the NOPS CT is approved and is not placed in service until the first quarter of 2021, under traditional practice before the Council, the pro forma(s) to the rate case generally would not extend to the CT in-service date. Under this circumstance, if the Council does not approve the Advisors' recommended cost recovery or implementation of a FRP or decoupling mechanism, in-service recovery would not be achievable absent a rider. As such, ENO's proposed rider provides a reasonable fallback alternative to ensure in-service recovery of NOPS. Mr. Prep's own direct testimony cites at least one instance where the timing of a utility's rate case and an approved resource addition were not aligned.[701] In that case, the regulator (Colorado Public Utilities Commission) approved a rider to recover the utility's costs.[702] Similar circumstances were presented when the Council approved ENO's participation in the Power Purchase Agreement for output from Entergy Louisiana, LLC's Ninemile 6 Unit.[703]

If the modified PPCACR Rider were to be approved in the Combined Rate Case for implementation as part of a Formula Rate Plan ("FRP"), there should be no concern regarding single-issue ratemaking, as all revenues and expenses would be taken into account in establishing ENO's rates for a given evaluation/test period. A PPCACR Rider modified to use a different cost allocation methodology would establish a reasonable and appropriate mechanism by which future resource additions approved by the Council, like NOPS and potentially ENO's currently proposed rooftop solar project pending in Council Docket UD-17-05, may be recovered, without the need for multiple, inefficient, pancaked rate cases that may be required in the absence of an FRP (or equivalent mechanism) in periods of increasing capital investment. The PPCACR Rider would provide greater flexibility in supporting ENO's need to recover these types of large investments for Council-approved resources on a contemporaneous in-service basis, particularly in the absence of a FRP or decoupling mechanism. During cross-examination, Mr. Prep acknowledged that his assumption regarding the approval of a FRP or decoupling mechanism is

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[701] Advisors Exhibit Prep-1 (Prep Direct) at 16.

[702] Public Service Company of Colorado, Docket No. 03A-436E, Decision No. C04-476, 234 PUR4th 329, Colorado Public Utilities Commission, May 10, 2004.

[703] Council Docket No. UD-11-03, Resolution R-12-29 (Feb. 2012).

hypothetical, such that there is uncertainty, at this time, that one of these mechanisms would be approved by the Council.[704]

Ideally, an FRP structure agreed-upon by the Company and the Council and the exact recovery rider would be the most expeditious and balanced framework for addressing this evolution in ENO's operations, as it provides benefits to the Company and customers as described above. However, with or without the FRP or similar mechanism, the PPCACR Rider would resolve any timing issues that would otherwise result in regulatory lag, ensure only the cost of the resource is recovered from customers, and provide the Company and its stakeholders needed assurances (*i.e.*, that full, incremental recovery will be accomplished on a timely basis), while obtaining the benefits of increased reliability in ENO's service area and avoidance of the burden of costly, inefficient pancaked rate cases.

4. Mr. Prep and Mr. Brubaker recommend that the methodology for allocating costs under the PPCACR Rider be re-examined.[705]

The Combined Rate Case provides an opportunity for the PPCACR Rider to be restructured in a manner that comports with more traditional allocation methodologies, a restructuring that ENO supports. The Company does not endorse one cost allocation methodology over another and, as yet, has not determined what will be proposed in its rate case application regarding cost allocation/rate design of the PPCACR Rider. ENO notes that it would not oppose allocation on a demand basis.

5. Air Products proposes that ENO's recovery of the NOPS-related non-fuel revenue requirement be deferred until the Council has completed its prudence review of the Project.

[704] Tr. (Prep) 12/21/17, at 136-37.

[705] Advisors Exhibit Prep-1 (Prep Direct) at 16; *see* Air Products Exhibit Brubaker-1 (Brubaker Direct) at 4, 12-13.

Air Products objects to recovery of the NOPS-related non-fuel revenue requirement through an exact recovery. Mr. Brubaker claims that "ENO does not need to have an exact cost recovery rider of any kind. Rather it can capitalize and defer for later recovery (after conclusion of a prudence review) the non-fuel costs associated with any new unit, should it be approved by the Council. This prudency review can occur in the context of a general rate case, or in an annual FRP review proceeding."[706] First, ENO notes that in the absence of in-service recovery of the NOPS-related non-fuel revenue requirement and deferral of the NOPS-related non-fuel revenue requirement, ENO would be exposed to a significant loss of earnings and decline in its financial metrics.[707]

As a hypothetical example, ENO's response to Advisors' Data Request No. 10-20, Exhibit SLM-3 attached to the Rebuttal Testimony of Ms. Lovorn-Marriage, provides the results of a hypothetical, high-level analysis that assumed a NOPS Alternative Peaker COD in January 2016 with no recovery of per book expenses, *i.e.* O&M, depreciation, and interest, for the first twelve months.[708] The calculation demonstrates that if recovery of the NOPS Alternative Peaker revenue requirement were to be delayed for one year from the COD, ENO could be at risk of forever losing more than a quarter of its net income just in that that year due to the added expenses associated with the plant without contemporaneous revenue to offset those costs. It should be evident that without contemporaneous recovery, in addition to not being afforded an opportunity to recover the costs of operating the plant depicted in ENO's response to Advisors Data Request No. 10-20, ENO would not be in a position to make the significant investment in NOPS without the opportunity to earn any equity return on that investment.

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706 Exhibit ENO Lovorn-2 (Lovorn-Marriage Rebuttal) at Exhibit SLM-4.

707 *See* ENO Exhibit Todd-2 (Todd Direct) at 9; ENO Exhibit Todd-3 (Todd Supplemental and Amending Direct) at 8.

708 ENO Exhibit Lovorn-2 (Lovorn-Marriage Rebuttal) at Exhibit SLM-3, p. 12.

Any delay in recovery of the NOPS-related non-fuel revenue requirement undermines ENO's opportunity to recover its Council authorized return and would negatively affect ENO's financial metrics.[709] For example, the size of this investment exceeds ENO's annual operating cash flows.[710] This demonstrates that ENO cannot absorb the regulatory lag on an investment the size NOPS without access to capital markets. Depending on the duration of the delay, ENO could experience a significant decline in financial metrics that would make it more challenging to attract capital on favorable terms.[711] Mr. Brubaker has estimated that the Council's prudence review could take up to a year, during which time the project would continue to accrue carrying costs.[712] During that time, ENO must be prepared to potentially access alternative sources of cash, which could further increase ENO's cost of service by the corresponding cost of capital. For these reasons, implementation of an in-service PPCACR Rider modified in accordance with generally accepted cost allocation principles would provide a lower cost recovery method than the proposal offered on behalf of Air Products.[713]

6. Mr. Prep's proposed two-step recovery method could be reasonable if ENO is assured that the recovery of the NOPS revenue requirement will commence with the RICE COD.

As explained in the Rebuttal Testimony of Company witness Ms. Lovorn-Marriage,[714] Mr. Prep's proposed method for recovery of the NOPS non-fuel revenue requirement could be reasonable as long as ENO is assured by the Council that the recovery of the NOPS revenue requirement will commence with the Project's COD. Under the proposal contained in Mr. Prep's

709 *Id.* at 12.

710 *Id.*

711 *Id.*

712 *Id.* at Exhibit SLM-4.

713 *Id.* at 18.

714 *Id.* at 14-15.

Direct Testimony, the first step in this process would be the implementation of rates resulting from the Combined Rate Case, which is estimated to be effective August of 2019.[715] The second step of this process would increase rates to capture the costs of the Project beginning on its COD, which would appropriately match the cost of the units with its expected revenue recovery.[716] As stated, ENO agrees that this cost recovery methodology could be a reasonable path forward, assuming this approach to recovery is approved by the Council.

ENO notes that, as explained in the rebuttal testimony of Ms. Lovorn-Marriage,[717] with respect to the NOPS CT, it is reasonable to expect that the NOPS CT would not reach its COD until the first quarter of 2021. Under this timeline, it is unclear how the "second step" would align with a decoupling mechanism and/or FRP; or, how the "second step" would be implemented in the absence of a decoupling mechanism or FRP. ENO believes this issue is not insurmountable and could be resolved through collaboration with the Council's Advisors; as these details can be resolved in the Combined Rate Case. In fact, during cross-examination, Mr. Prep indicated that in the event the CT is approved by the Council:

> "the proposal would be similar to that is in the combined rate case, we would recognize the anticipated date of commercial operation. There would be, I would expect a pro forma set of adjustments to recognize that. However, since it is further out, I would expect there to be more attention paid to the pro forma adjustments and any other filings prior to commercial operation that would be necessary. And that would all be within the combined rate case and it would be in details that I wouldn't be able to anticipate or describe right now."[718]

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715 Advisors Exhibit Prep-1 (Prep Direct) at 21-22.

716 *Id.*; Advisors Exhibit Prep-1 (Prep Direct) at 21-22.

717 ENO Exhibit Lovorn-2 (Lovorn-Marriage Rebuttal) at 14-15.

718 Tr. (Prep) 12/21/17, at 140.

In either case, in order to proceed with the investment required to construct NOPS, ENO should be provided reasonable assurances by the Council that such investment would be recovered on a timely/in-service basis.

7. It is reasonable to recover costs of the LTSA for the CT through the FAC because the LTSA costs are similar to fuel costs in that they are correlated with production and will be incurred only when the CT is actually operating.

ENO proposes that if the NOPS CT is approved, the expenses incurred under a LTSA should be recovered through ENO's fuel adjustment clause ("FAC"). As indicated in the testimony of ENO witness Mr. Robert A. Breedlove, ENO expects that the LTSA will require payment for certain major maintenance activities covered in the scope, with such payments varying based on the utilization of the CT, including the number of unit starts and hours of run-time.[719] Thus, the LTSA costs will be similar to fuel costs in that they are correlated with production and will be incurred only when the NOPS is actually operating.[720] The variable nature of these expenses and the fact that these expenses are tied to the run-time of the unit makes them appropriate for recovery through the Company's FAC.[721] FAC recovery is appropriate as it will ensure that customers pay only the actual LTSA costs when such costs are actually incurred and the benefits of the services received.[722] Recovering these costs through base rates gives rise to the possibility that the Company would recover amounts greater or less than the actual costs incurred. Certain jurisdictions permit recovery of LTSA through an FAC rider as ENO is proposing here. Of particular note, consistent with its General Order U-21497,

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719 ENO Exhibit Breedlove-1 (Breedlove Direct) at 7-9.

720 ENO Exhibit Todd-2 (Todd Supplemental and Amending) at 10-11; ENO Exhibit Lovorn-2 (Lovorn-Marriage Rebuttal) at 9.

721 ENO Exhibit Todd-2 (Todd Supplemental and Amending) at 10-11; ENO Exhibit Lovorn-2 (Lovorn-Marriage Rebuttal) at 9.

722 ENO Exhibit Lovorn-2 (Lovorn-Marriage Rebuttal) at 9.

the Louisiana Public Service Commission ("LPSC") has on several occasions authorized FAC recovery of LTSAs for Entergy Louisiana, LLC's combined cycle units. General Order U-21497 established standards governing the treatment and allocation of fuel costs by all LPSC-jurisdictional electric utility companies. The LTSAs approved by the LPSC for recovery through the FAC contain terms similar to that anticipated for the NOPS CT.

C. <u>The Company's proposed Monitoring Plan is reasonable and uncontested.</u>

The Company has proposed a Monitoring Plan that contemplates quarterly progress reports providing detailed information on the status of NOPS, its costs, and other activities that are critical to completing the Project in a timely manner.[723] The Monitoring Plan will help ensure that the Council stays well informed on Project development.[724] Although the Joint Intervenors have opposed certification, no party in this docket has challenged, though their pre-filed testimony, the Monitoring Plan proposed by the Company. The Advisors also support approval of the Monitoring Plan, but suggest that after receiving the quarterly reports described by ENO in the Monitoring Plan,[726] they should be allowed to (1) request other information "that may readily available and of interest to the Council;"[727] and (2) request to modify the format of the reports going forward, "provided, of course, that such changes to the format requirements do not place an undue burden on ENO."[728] Advisors witness Mr. Rogers stated that "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

723 ENO Exhibit Lovorn-1 (Lovorn-Marriage Direct) at 13; SLM-2.

724 ENO Exhibit Lovorn-1 (Lovorn-Marriage Direct) at 6.

726 *See id.* at Exhibit SLM-2.

727 Advisors Exhibit Rogers-1 (Rogers Direct) at 49.

728 *Id.*

able to review the actual level of detail provided by ENO."[729] ENO does not object to the Council Advisors proposal.

Conclusion

As the City of New Orleans celebrates its Tricentennial, it is important for the Council, citizens, and stakeholders to take steps to secure the City's bright future. Appropriate investment in infrastructure and a reliable electric utility system are indispensable to that future, and the construction of NOPS is a step that the Council should approve. ENO has provided the Council with two options for NOPS, and the record evidence in this docket establishes that both the CT and the Alternative Peaker have significant benefits. Forecasts show that ENO has a need for additional peaking capacity in order to meet future load. Either plant would be able to meet that need while providing the City with a long-term resource that will improve supply conditions and support reliable service to the City during periods of peak demand and unplanned events, and either will mitigate market and supply-related risks. Either plant will have the effect of eliminating the risk of cascading outages in New Orleans and the ability to provide reliability benefits such as support for restoration efforts following major weather events.

In addition to providing an efficient, modern generating unit that can contribute to meeting the City's reliability needs, construction and operation of NOPS will lead to significant economic benefits – totaling hundreds of millions of dollars – in terms of new business sales, household earnings, and jobs in both the City and State economies. These economic benefits would not arise were the Council to deny ENO's Supplemental and Amending Application for NOPS. And these benefits will not come at the expense of the environment or the community in

[729] *Id.*

New Orleans East. The Company's witnesses have shown that NOPS will not adversely affect public health or the environment.

In short, customers face a possibility of harm if the Council were to delay or deny certification of NOPS, as requested by the Joint Intervenors. Because NOPS would serve the public interest, ENO respectfully requests that the Council approve its Supplemental and Amending Application and certify construction of either the CT or the Alternative Peaker. The Company also requests that the Council approve a cost recovery mechanism that provides ENO a full and fair opportunity to recover prudently-incurred costs on a timely/in-service basis.

Respectfully submitted:

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CERTIFICATE OF SERVICE
CNO Docket No. UD-16-02

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