WILKERSON & ASSOCIATES, PLC
ATTORNEYS & COUNSELLORS AT LAW
THE POYDRAS CENTER, SUITE 1913
650 POYDRAS STREET
NEW ORLEANS, LA 70130
TELEPHONE: (504) 522-4572
FAX: (504) 522-0728

January 19, 2018

Via U.S. Mail and/or Email

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

RE: Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief
Council Docket No. UD-16-02

Dear Ms. Johnson:

Please find enclosed the public version of the Post-Hearing Brief of the Advisors to the City Council of New Orleans in the referenced proceeding, which brief is being filed pursuant to Council Resolution R-17-426. The brief is being filed in a redacted version because it includes or is based on information deemed by parties to this proceeding to be highly sensitive protected material, in accordance with Council's Official Protective Order. A non-redacted version is being served on Entergy New Orleans, Inc. and the Intervenors in this docket. It is requested that you file said pleading in accordance with your normal procedure, and that you provide us a time-stamped copy of same to certify receipt.

With best regards, I remain

Sincerely,

WILKERSON & ASSOCIATES, PLC

Walter J. Wilkerson

WJW/krb
Enclosure
cc: Official Service List
All Councilmembers

PUBLIC VERSION

BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

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

POST-HEARING BRIEF
OF THE ADVISORS TO THE CITY COUNCIL OF NEW ORLEANS

Walter J. Wilkerson
Wilkerson & Associates, PLC
650 Poydras Street, Suite 1913
New Orleans, Louisiana 70130
Phone: (504) 522-4572
Facsimile: (504) 522-0728
Email: wwilkerson@wilkersonplc.com

Clinton A. Vince
Emma F. Hand
Presley R. Reed, Jr.
Dentons US LLP
1900 K Street, N.W.
Washington, D.C. 20006
202-408-6400 (Telephone)
202-408-6399 (Facsimile)
clinton.vince@dentons.com
emma.hand@dentons.com
presley.reedjr@dentons.com

Jerry A. Beatmann, Jr. (Bar No. 26189)
Dentons US LLP
650 Poydras Street, Suite 2850
New Orleans, LA 70130
504-524-5446 (Office)
504-256-6142 (Cell)
jay.beatmann@dentons.com

Dated: January 19, 2018

Table of Contents

Table of Contents ii

Table of Authorities iv

Introduction and Statement of the Case 1

Background 7

- **I. System Agreement Settlement** 8
- **II. ENO's IRP Process** 11
- **III. NOPS Application** 14

Argument 18

- **I. WHETHER ENO'S ANALYSIS OF NEED IS SUFFICIENT TO JUSTIFY AN INVESTMENT**: ENO has sufficiently demonstrated a critical need for a generation resource to be built in New Orleans. 18
  - **A. WHETHER ENO HAS DEMONSTRATED A CAPACITY NEED**: A capacity need does exist and must be addressed, though ENO has overestimated the need. 18
  - **B. WHETHER ENO HAS DEMONSTRATED A RELIABILITY NEED**: ENO has demonstrated a critical reliability need for generation resources in Orleans Parish to maintain the reliability of the electric grid and avoid cascading outages impacting most of the city. 30
- **II. WHETHER ENO'S CHOICE OF TECHNOLOGY(IES) IS IN THE PUBLIC INTEREST:** The construction of the RICE Alternative in combination with the incorporation of renewable technologies and realistically achievable cost-effective DSM potential in ENO's service territory is in the public interest. 42
  - **A. WHETHER ENO'S SELECTION OF A CT UNIT IS IN THE PUBLIC INTEREST:** ENO has not demonstrated that its CT proposal is in the public interest. While it would comply with applicable environmental regulations, it is a larger investment than the identified need requires and puts ratepayers at risk of overpaying for capacity they do not need. 44
  - **B. WHETHER ENO'S SELECTION OF A RICE UNIT IS IN THE PUBLIC INTEREST**: The construction of the RICE Alternative in combination with the incorporation of renewable technologies and realistically achievable cost effective DSM potential in ENO's service territory is in the public interest. 60

C. **WHETHER ENO APPROPRIATELY CONSIDERED A FULL RANGE OF OPTIONS TO MEET THE IDENTIFIED NEED**: In light of the very specific reliability need identified, ENO has considered a reasonable range of options. The other options urged by Intervenors would not sufficiently address the identified needs. 75

III. **WHETHER ENO'S SELECTION OF THE MICHOUD SITE IS REASONABLE**: The Michoud site is a reasonable choice, given the identified need. 98

A. **The Michoud Location Has Several Advantages** 98

B. **Testimony In The Record Indicates That The Proposed Units Will Not Contribute to Additional Subsidence at Michoud and that Flood Risks Have Been Substantially Mitigated** 100

C. **There Is No Evidence In The Record That Siting a Project at Michoud Will Perpetuate Racial Injustice or that the Proposal Is Racially Motivated** 108

IV. **WHETHER ENO'S PROPOSED COSTS, COST RECOVERY MECHANISM, AND MONITORING PLAN ARE JUST AND REASONABLE AND SHOULD BE APPROVED BY THE COUNCIL**: The estimate of costs is reasonable, but the proposed cost recovery mechanism and monitoring plan are not and a different cost recovery mechanism and modified monitoring plan are required. 126

A. **Cost recovery mechanism** 126

B. **LTSA cost recovery** 133

C. **Rate Impact** 136

D. **Monitoring Plan** 139

Conclusion 139

Certificate of Service 142

Table of Authorities

FEDERAL CASES

Alliance for Affordable Energy, Inc. v. Council of City of New Orleans,
578 So. 2d 949 (La. Ct. App.4th Cir.), *writ granted sub nom. Alliance for Affordable Energy, Inc. v. The Council of the City of New Orleans*, 585 So. 2d 554 (La. 1991), *writ granted*, 585 So. 2d 555 (La. 1991), *vacated sub nom. Alliance for Affordable Energy v. Council of City of New Orleans*, 588 So. 2d 89 (La. 1991) 122

Gulf States Utilities Co. v. Louisiana Public Service Commission,
578 So. 2d 71 (La. 1991) 122

North Baton Rouge Environmental Ass'n v. Louisiana Department of Environmental Quality,
805 So. 2d 2558 (La. App. 1 Cir. 2001) 111, 112, 113

ADMINISTRATIVE CASES

Entergy Services, Inc.
149 FERC ¶ 61,262 (2014) 9, 118

In the Matter of the Application of Hawaiian Electric Co., Inc.,
Docket No. 2014-0113, Order No. 33178 (Sept. 29, 2015) 4

Upper Michigan Energy Resources Corp.,
Case No. U-18224, Opinion and Order (Oct. 25, 2017) 5

COUNCIL RESOLUTIONS

Resolution No. R-10-142 (Mar. 25, 2010) 81

Resolution No. R-13-432 (Nov. 21, 2013) 117

Resolution No. R-13-433 (Nov. 21, 2013) 117

Resolution No. R-14-224 (June 5, 2014) 12

Resolution No. R-14-364 (Sept. 4, 2014) 13

Resolution No. R-15-437 (Sept. 3, 2015) 11, 119

Resolution No. R-15-524 (Nov. 55, 2015) 8, 11, 116, 120

Resolution No. R-16-103 (Apr. 7, 2016) 130, 140

Resolution No. R-16-104 (Apr. 7, 2016) 13

Resolution No. R-16-506 (Nov. 3, 2016) 16, 77, 116

Resolution No. R-17-100 (Feb. 23. 2017) 12, 121

Resolution No. R-17-426 (Aug. 10, 2017) 16, 17, 116

Resolution No. R-17-429 (Aug. 10, 2017) 82

STATUTES AND REGULATIONS

5 U.S.C. § 554 (d). 122
Home Rule Charter of the City of New Orleans, Article III, Section 3-130 122
La. Rev. Stat. Ann. § 45.1163.3..122

Introduction and Statement of the Case

The Advisors, having reviewed the evidence presented in this case by Entergy New Orleans, LLC ("ENO" or the "Company") and the intervenors and performed our own analysis, conclude that ENO customers are presently at risk of significant electrical outages of potentially long duration and such risk will persist until some form of reliable, fast-start generation is obtained locally. This is a serious and unacceptable risk and it must be addressed; delay only prolongs the extent to which customers are vulnerable. ENO has proven that the risk cannot presently be addressed through upgrades to the transmission system alone -- local, all-weather generation is essential.

The Council of the City of New Orleans ("Council") is presented with three options in this case, only two of which the Advisors believe could address the identified reliability and capacity needs -- the option to build a 226 MW combustion turbine ("CT Alternative") or the option to build the 128 MW reciprocating internal combustion engine generator ("RICE Alternative"). The third option -- to reject both proposals and instead rely upon ENO's ability to perform transmission upgrades to mitigate the reliability concern and meet the capacity need with a combination of demand-side management ("DSM"), distributed generation ("DG") and renewable resources ("Transmission Alternative") is not a realistic, reliable, or prudent method of addressing the identified concerns. As between the CT Alternative and the RICE Alternative, the Advisors support the RICE Alternative as being the least risky option to ratepayers and the option most closely matched to the identified needs of the New Orleans community.

The RICE Alternative has many advantages over both the CT Alternative and the Transmission Alternative. Nearly half the size of the CT Alternative, the RICE Alternative more closely fits ENO's need. In addition, the RICE Alternative would use 95% less groundwater than the CT Alternative and would represent a 99.9% reduction in groundwater usage compared to the deactivated Michoud units previously operating at that site. Further, it has black start capability, and would provide a local resource for ENO to respond to storm events and other types of outages. Not building a generator and instead relying upon the utility's ability to upgrade its transmission system is not a realistic method of addressing the issue.

Conversely, the CT unit is too big and relies too heavily on the Midcontinent Independent System Operator, Inc.'s ("MISO") capacity market prices increasing dramatically over historic levels for its economic viability. The CT unit also lacks built-in "black start" capability in a crisis situation.

The Transmission Alternative is likely to be difficult to impossible to effectively implement in the time frame needed -- ENO might not be able to obtain the required approvals from MISO to take transmission lines out of service to perform the necessary upgrades, and even if it can, it means putting an already stressed and heavily loaded transmission system under increased stress for months at a time by taking lines out of service, thereby further exacerbating transmission reliability issues. Because of this issue, ENO also would have to stagger upgrades which will take much longer than building a plant.

In addition, the Transmission Alternative puts all of ENO's eggs into one basket by leaving the City 100% dependent upon the repair of transmission lines to restore power after a blackout, which can take days or even weeks to accomplish.[1] There is no evidence in the record

[1] The Advisors note that recent news reports indicate that MISO asked utilities in MISO South to encourage their customers to reduce usage to due to a potential shortage of capacity during a recent weather event. http://www.fox8live.com/story/37291783/entergy-customers-free-to-use-power-as-normal and

that the Council's goal of reducing consumption through the Energy Smart program by 2% of Entergy's annual kWh sales ("2% DSM Goal") is achievable and there is substantial evidence that this approach is NOT achievable. It would go against the weight of the evidence in the record to require ENO to rely upon meeting the 2% DSM Goal in its long-range planning. Also, ENO has submitted evidence that renewables, even with battery storage, cannot meet the capacity needs or reliability needs of ENO. No analysis or data has been provided in the record to disprove this concern. Similarly, it has not been shown that it is feasible to site utility-scale solar photovoltaic ("PV") in or around the Michoud site.

Both the CT Alternative and the RICE Alternative represent a significant reduction in air emissions and groundwater usage from that of the two units at the Michoud site that were deactivated in 2016. ENO has provided sworn testimony, backed up with evidence, that it will comply with all, local, state, and federal laws applicable to the plant, including all environmental laws and regulations set forth by the United States Environmental Protection Agency ("EPA") and the Louisiana Department of Environmental Quality ("LDEQ").

No party has established a basis for the Council to apply different environmental criteria to this plant, nor a basis to determine what such criteria would be. The Advisors believe that the issues raised with respect to environmental hazards, flooding and subsidence should be fully addressed by conditioning the Council's approval upon compliance with all applicable laws. The Council should specifically require ENO to demonstrate such compliance by filing copies of all permits obtained and any other rulings by any agency with authority over the project.

---

https://www.livingstonparishnews.com/entergy-asks-louisiana-customers-to-reduce-electricity-today-or-face/article_d2233344-fc16-11e7-a0fa-4b9f1ae12321.html.

The RICE unit is a proven technology that many regulators are turning to in order to support the transition to renewables and ensure reliability. For example, in Hawaii, which adopted one of the nation's most aggressive renewable portfolio standards ("RPS") in 2014, calling for 100% renewables resources by 2045,[2] the Hawaii Public Utilities Commission ("HPUC") issued a Decision and Order in September of 2015 approved an application by Hawaiian Electric Company, Inc. ("HECO") to purchase and install a firm, dispatchable 50 MW power plant, configured with six 8.4 MW multi-fuel capable RICE generator sets.[3] In approving the RICE unit, the HPUC noted, among other things, that the RICE generator "increases the operational flexibility and reliability of HECO's system" and "may enhance HECO's capability to operate its grid to accommodate increased amounts of renewable energy."[4] The HPUC further explained that:

> Although existing generating facilities have the capability to compensate for the current fluctuations caused by variable renewable generation from wind and solar, Hawaiian Electric is already experiencing grid fluctuations that challenge this capability. As more variable renewable energy is added to the grid, and as new wind and solar generators become more concentrated, (i.e. larger industrial solar photovoltaic ("PV") sites versus distributed residential PV), these fluctuations are anticipated to increase in magnitude and frequency. Quick-starting units such as the RICE units selected for the Project are needed to complement the technical advantages of existing units to not only ensure reliable power to customers, but to enable the integration of more cost-effective variable renewable generation.[5]

The Michigan Public Service Commission ("MiPSC") also recently approved an application by the Upper Michigan Energy Resources Corporation ("UMERC") to build two

---

[2] *See e.g.*, http://www.hawaiicleanenergyinitiative.org/wp-content/uploads/2015/02/HCEI_FactSheet_Feb2017.pdf

[3] *In the Matter of the Application of Hawaiian Elec. Co., Inc.*, Docket No. 2014-0113, Order No. 33178, Decision and Order, at 1, (Sept. 29, 2015).

[4] *Id.*

[5] *Id.* at 23.

RICE units in Michigan's Upper Peninsula for a total of 183 MW.[6] Upon issuing that decision, MiPSC Chairman, Sally Talberg issued a statement wherein she stated:

> The new gas-fired electric generation being approved by the Commission today serves this unique need. It is an anchor to stabilize electric reliability in the region in a least-cost manner. It continues the UP's journey toward more affordable rates. This clean, efficient generation will significantly reduce emissions of mercury and other pollutants compared to the coal plant it will replace. And it is adaptable to the changing energy needs of the region—whether that is helping to serve a growing customer base spurred by economic development, providing a foundation for adding renewable energy, or investing in ways to cut energy waste in homes and businesses.[7]

Locating the plant at the Michoud site is a reasonable choice by the utility. The physical requirements of the system are best served by placing a facility within a specific geographic location, and the Advisors believe that within that geographic location, the Michoud site is the best suited to meet the needs of the community for various reasons. The site is in a sparsely populated, industrial neighborhood in the City that has been used as a power plant site for over 50 years. ENO already owns the land, and the site has significant gas pipeline, transmission, and distribution infrastructure, as well as an administration building already built, all of which will result in significant cost savings for customers.

Certain parties have argued that locating a plant at the Michoud site would perpetuate environmental racism, because New Orleans East, the area surrounding Michoud, is a predominately minority neighborhood. However, the eastern part of the City would be the most heavily impacted by the outages ENO seeks to prevent by placing a plant at the Michoud site. ENO has also submitted evidence that the RICE Alternative will bring hundreds of millions of

---

[6] *Upper Michigan Energy Resources Corp.*, Case No. U-18224, Opinion and Order (Oct. 25, 2017). *See also* http://www.michigan.gov/mpsc/0,4639,7-159-16400_17280-450695--,00.html.

[7] http://www.michigan.gov/mpsc/0,4639,7-159-16400_17280-450695--,00.html

dollars in economic benefits to Orleans Parish in terms of new sales at companies in the Parish ($180.2M during construction, $12.7M annually thereafter), new earnings for Parish residents ($24.6M during construction, $5.9M annually thereafter), new jobs (80 during construction and 59 permanent jobs thereafter) and taxes ($861,430 during construction and $209,122 annually thereafter).[8]

Evidence in the record indicates that the environmental impact on New Orleans East will be significantly reduced compared to the impact of the plants previously operating at Michoud, and will remain within the limits set by the EPA and LDEQ. Thus, the Advisors believe there will be no disproportionate, significant adverse effect on residents of New Orleans East, and that there will be significant benefits to them in terms of both electric reliability and economics. Without the plant there is substantial risk that multiple minority neighborhoods would be at a serious and unacceptable risk of outages. No party has presented sufficient evidence of discriminatory intent to demonstrate that citing the plant at the Michoud location to reduce serious risk of cascading outages would perpetuate environmental discrimination.

Certain parties also argue that the process for evaluating the plant is flawed and has lacked transparency and public input. This is simply false. The Council has undertaken extensive public process to evaluate this case in an open and transparent manner. There have been over 21 public meetings regarding the proposal, including meetings in every Council district. There have been multiple opportunities for parties and members of the public to address the Council regarding the proposal at public Utility, Cable, Telecommunications and Technology Committee ("UCTTC") meetings and at the Council's public hearing. Any party with an interest

[8] Rice-4, Exhibit CLR-3 at 2. ENO also submitted a study of the economics of the CT Alternative, which can be found at Rice-1, Exhibit CLR-2.

in the case was able to intervene in the proceeding, conduct discovery, submit evidence and argue their case. There was a five-day evidentiary hearing for the parties to conduct cross-examination of witnesses before a Hearing Officer, and finally, an opportunity to file a brief with the Council expressing their views of the case. The Council has given significant opportunity for the public and the affected neighborhoods to learn about the proposal and make their views known to the Council. While throughout the process the Council has been duly aware of and sensitive to the fact that views vary among the public with respect to the plant, when considering highly technical matters concerning critical infrastructure in the City, it must base its decision on the record evidence before it, including the scientific, engineering, and economic evidence submitted by experts and properly entered into the record where all parties have had the opportunity to probe and test the evidence. The record in this case is very well developed, the Council has now received over 2,700 pages of testimony and evidence in this matter.

The Advisors believe that the level of risk for New Orleans is so significant that further delay would be highly imprudent. The matter is sufficiently ripe for Council decision.

Background

For more than 50 years, the Michoud generating station in New Orleans East served as the cornerstone of ENO's operating system. ENO's transmission was largely designed and evolved around the Michoud plant.[9] In June of 2016, ENO made the economic decision to deactivate Michoud based on consideration of maintenance and operational issues.[10] This resulted in the loss to ENO of approximately 781 MW of local capacity.[11]

[9] Hr'g Tr. 12/18/17, 336:4-9.
[10] Rice-1 at 3:7-8.
[11] Rice-1 at 3:8.

Since at least the 1990s until its deactivation, the Michoud generating station was committed to operation during high load periods due to local area voltage and reliability problems, and in the event of electrical system contingencies in the Downstream Gypsy ("DSG") area. For example, in 2008 when Hurricane Gustav struck the region, Michoud provided essential service to New Orleans when other portions of Entergy's system were down.[12] When ENO began considering the retirement of the last Michoud unit in early 2015, the Council and the Advisors were deeply concerned about ENO's ability to continue to provide reliable service at a reasonable cost with no generation in the City, and particularly with no resource in the eastern region of ENO.[13]

During that same time period when ENO was considering deactivation of Michoud, the Advisors were working with ENO both on negotiating the termination of the Entergy System Agreement[14] and on ENO's Integrated Resource Planning ("IRP") process. In both of these processes, the Council and the Advisors were working with ENO to address ENO's generation deficit and to mitigate the risks associated with a total lack of a local resource in New Orleans.

I. System Agreement Settlement

When negotiations to terminate the Entergy System Agreement began under the auspices of the Federal Energy Regulatory Commission ("FERC"), it was vital to the Advisors that ENO have access to capacity and energy at a reasonable cost. The resource sharing and cost-allocation arrangements under the 50-year-old System Agreement had provided significant benefits to New Orleans, and the end of that arrangement was potentially detrimental to ENO's customers, particularly with the clock already winding down on the remaining life of Michoud.

---

[12] C. Long-1 at 13:17-14:3; C. Long-3 at 28:1-29:3.
[13] Vumbaco-1 at 17:16-18.
[14] *See* Resolution No. R-15-524 (Nov. 5, 2015) (related to Council Docket Nos. UD-13-03 and UD-13-04).

The proceedings surrounding the termination of the System Agreement took place in several venues. A filing by Entergy Services, Inc. ("Entergy") at FERC triggered an intervention period which allowed any interested parties to intervene in FERC's public proceeding regarding the proposal to terminate the System Agreement. Once that intervention period had elapsed, FERC set the proceeding for settlement discussions facilitated by a FERC Administrative Law Judge ("ALJ").[15] The Advisors negotiated with ENO and the other parties to the case on behalf of the Council, and a settlement between all parties to the case was ultimately reached. On August 14, 2015, Entergy filed the settlement in the public proceeding at FERC.[16] The Settlement Agreement was subject to review and approval of the Council as well as of the other regulatory commissions party to the Settlement Agreement.

The Settlement Agreement resolved a host of issues. Among these, the Settlement Agreement provided that ENO would explore the possibility of developing peaking generation in New Orleans. It did not mandate, pre-select or pre-approve any particular resource or any particular site. Specifically, the Settlement Agreement provided:

> ENO will use reasonable diligent efforts to pursue the development of at least 120 MW of new-build peaking generation capacity within the City of New Orleans. As part of this commitment, ENO will fully evaluate Michoud or Paterson, along with any other appropriate sites in the City of New Orleans, as the potential site for a combustion turbine ("CT") or other peaking unit to be owned by ENO, or by a third party with an agreed-to PPA to ENO. This evaluation will take into consideration, among other material considerations, the results of the Michoud site analysis that was completed in connection with the Summer 2014 Request for

---

[15] *Entergy Services, Inc*., Combined Notice of Filing #2, Docket Nos. ER14-75-000, *et al*. (Oct. 15, 2013). *Entergy Services, Inc.*, Order Conditionally Accepting Notices of Cancellation and Accepting and Suspending Proposed Amendment, Establishing Hearing and Settlement Judge Procedures, and Consolidating Proceedings, 149 FERC ¶°61,262 (2014).

[16] Settlement Agreement of Entergy Services, Docket Nos. ER14-75, *et al*. (Aug. 14, 2015) ("Settlement Agreement").

> Proposal; and
>
> ENO commits to use diligent efforts to have at least one future generation facility located in the City of New Orleans; … .[17]

Further, the agreement did not assure that any resource would be approved for construction in the City. It reflected the Council's concern about the deactivation of Michoud, which ENO had long relied on to support reliability in the City, at the same time that Entergy was terminating the resource sharing contract that had benefitted New Orleans for decades.[18] In light of this, the Settlement established ENO's commitment to examine the potential of a local resource.

To the extent that ENO identified an appropriate resource and location, any approval would be subject to the full public interest determination that the Council undertakes in evaluating any request by ENO to add generation to its portfolio of resources serving New Orleans. This was spelled out in the Settlement Agreement, which was filed at FERC subject to formal approval by the Council and the other retail regulators party to the case:

> The commitments set forth in this [section] are subject to mutually satisfactory resolution of all material considerations, including, without limitation: (a) financial feasibility for ENO; (b) affordability for ENO customers; (c) economic feasibility in comparison to other potential projects, locations, or alternatives; (d) timely rate recovery; (e) regulatory jurisdiction over such facility(ies) to the extent not owned by ENO; and (f) consistency with sound utility practice and planning principles.[19]

Before approving the Settlement Agreement, the Council provided all parties affected by it an opportunity to understand the proposal, submit comments and have their views

[17] *Id.* at 13-14.
[18] Hr'g Tr. 12/18/17, 247:18-248:11.
[19] Settlement Agreement at 14.

considered.[20] The Council established a procedural schedule that allowed the parties to its proceedings addressing the System Agreement termination (Docket Nos. UD-13-03 and UD-13-04), as well as members of the public, to submit comments and reply comments regarding the proposed Settlement Agreement, which the Council considered in deciding whether to approve the settlement. Consistent with the Council's practice generally, the process included the publication of notice of the proceedings.

Public meetings were held by the UCTTC and the full Council on September 30 and November 5, 2015, respectively, where the Settlement Agreement was considered. No party or member of the public opposed the Settlement Agreement. On November 5, 2015, the Council adopted Resolution No. R-15-524 which found the FERC Settlement Agreement, including ENO's commitment to use reasonable diligent efforts to pursue development of a peaking resource in the City, to be just and reasonable and in the public interest.[21] The Resolution was made available to the public in the Council's usual manner and was discussed at a Council UCTTC meeting, which was recorded on video, broadcast and made available over the Council's website.[22]

II. ENO's IRP Process

Through the IRP proceedings, ENO identifies what long-term resource needs it has and conducts an economic analysis of what type of resource is likely to be the most economically beneficial in meeting an identified resource need. The IRP does not dictate the implementation

[20] Resolution No. R-15-437 at 4 (Sept. 3, 2015).
[21] Resolution No. R-15-524 at 12.
[22] Videos of Council meetings are available in the Council's on-line archives, http://www.nolacitycouncil.com/video/video_legislative.asp.

of specific projects; rather, it identifies need and gives the utility a general direction to explore in meeting that need.

In the course of preparing its 2015 Final IRP, ENO engaged in extensive modeling and considered a wide range of different future scenarios and resource alternatives. That process identified the Company's substantial need for peaking and reserve capacity.[23]

ENO's IRP process provided multiple opportunities for meaningful public participation.[24] The Council has established a collaborative approach to long-term resource planning that provides interested parties access to substantial advance information about ENO's plans to meet its customers' power needs.[25] The IRP process was open to the public to intervene and participate formally as a party to the proceeding, or simply to attend multiple technical conferences to hear about the IRP and present two minutes of verbal comments to the Council in a public hearing regarding the 2015 Final IRP.[26]

In the 2015 Final IRP process, the Council set forth four milestones and required that at each one, ENO (1) provide a report from ENO to the Intervenors, Advisors, public, and the Council; (2) hold a technical conference, (3) set up a question and answer period where all parties and members of the public may ask questions over ENO's website with answers publicly posted; (4) allow Intervenors to file comments on ENO's report, and (5) obtain feedback and input from the Council.[27]

---

[23] *In Re*: Resolution Regarding the Proposed Rulemaking to Establish Integrated Resource Planning Components and Reporting Requirements for Entergy New Orleans, Inc., 2015 Integrated Resource Plan, Docket No. UD-08-02, at 75 (Feb. 1, 2016) ("2015 Final IRP"); Rice-4 at 8:4-9.
[24] Resolution No. R-14-224 at 16 (June 5, 2014).
[25] Resolution No. R-14-224; Cureington-7 at 79:13-17.
[26] Resolution No. R-17-100 at 5-8 (Feb. 23, 2017).
[27] *See* Resolution No. R-14-224 at 16. *See also* discussion in Cureington-7 at 81 nn.111-114.

The Council subsequently took further steps to allow for participation by additional intervenors.[28] With Resolution No. R-14-364, many other parties were allowed to intervene in the 2015 Final IRP proceeding. Among the parties who intervened in that proceeding were Air Products, the Alliance for Affordable Energy, the Sierra Club and Posigen Solar Solutions, and at least nine other entities and organizations.[29]

ENO issued 30 days' notice of each technical conference and made materials available to the public. These meetings were held in a central location in the City, since the outcome of the IRP affects the whole city, including a public technical conference in New Orleans East regarding the 2015 Final IRP in May of 2016.[30] ENO held more technical conferences than the minimum required by the Council.[31] In response to feedback it received on the draft IRP plan, ENO took steps to increase transparency of the process and to incorporate stakeholder input.[32] ENO created a Stakeholder Input Case to supplement the 2015 Final IRP.[33] The Council also directed ENO to hold a technical conference and provide the opportunity for public review and comment on the 2015 Final IRP,[34] and a public hearing was held.[35]

The preferred portfolio selected by ENO in its 2015 Final IRP process included a 250 MW CT unit, but the IRP was not a formal proposal to construct the New Orleans Power Station ("NOPS").[36] By the time the Council's final order regarding the 2015 Final IRP was issued, ENO's Initial Application to construct NOPS had already been filed. The Council in its

---

[28] *See* Resolution No. R-14-364 at 7-8 (Sept. 4, 2014). *See also* Cureington-7 at 81 n.110.

[29] Cureington-7 at 81. *See also,* Resolution No. R-14-364 at 8, Resolution No. R-16-104 at 7 (Apr. 7, 2016).

[30] Cureington-7 at 82:1-13 and nn.115-117.

[31] Cureington-7 at 82:14-83:3.

[32] Cureington-7 at 83:10-14.

[33] Cureington-7 at 83:14-18.

[34] Resolution No. R-16-104 at 6-8.

[35] Resolution No. R-16-104 at 8.

[36] Cureington-7 at 79:23.

resolution accepting the IRP was extremely clear that its acceptance of the IRP did not, in any way, constitute approval of the ENO's NOPS application:

> 1. All issues related to ENO's NOPS CT proposal should be fully vetted in Council Docket No. UD-16-02 including, but not limited to the need for a CT, size, timing, environmental concerns, social justice, cost, transmission, and reliability considerations. **ACCEPTANCE OF THIS IRP SHALL HAVE NO PRECEDENTIAL EFFECT WITH RESPECT TO THE COUNCIL'S EVALUATION OF ENO'S NOPS CT APPLICATION IN COUNCIL DOCKET UD-16-02.**[37]

III. NOPS Application

ENO filed its original proposal to construct NOPS in June 2016 (Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief ("Initial Application")). The Initial Application outlined ENO's proposal to construct a 226 MW CT generation facility on the Michoud site in New Orleans East. In addition to seeking approval to construct NOPS, ENO seeks approval of a contemporaneous exact cost recovery rider on customer bills, effective beginning with commercial operation of the plant, to recover non-fuel costs. ENO indicated it was contemplating a long-term service agreement ("LTSA") with the original equipment manufacturer for major maintenance. If such an LTSA is executed, ENO seeks authorization to recover those costs through a fuel adjustment clause (FAC") mechanism. ENO also seeks approval of its proposed monitoring plan. ENO sought approval by January 2017, with the expectation that the CT would be in commercial operation by October 2019. ENO estimated that the cost of the project would be $216 million. In addition to citing its reliability and capacity need, ENO stated that construction of the project would have a positive impact on the New Orleans and Louisiana economies in terms of new business sales, household earnings and jobs.

[37] Resolution No. R-17-100.

On November 18, 2016, at the direction of the Council, ENO filed "Supplemental Testimony of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and for Timely Relief." This filing included additional testimony and analysis requested by the Council upon the advice of the Advisors.

In January 2017, ENO received an updated forecast of projected customer demand for the 20 year planning horizon. The updated load forecast indicated demand has moderated by an average of 40 MWs per year compared to the forecast used in the Initial Application. On February 14, 2017, after the Intervenors had filed their direct testimony but before the Council's Advisors filed direct testimony, ENO filed a Motion to Suspend the procedural schedule to analyze the implications of the updated forecast on its proposed project.

On July 6, 2017, ENO filed a "Supplemental and Amending Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief" ("Supplemental Application"). In this filing, ENO still advocated construction of the 226 MW CT Alternative, but also submitted an alternative proposal to construct a smaller 128 MW "Alternative Peaker" at the Michoud site. The alternative proposal entails construction of seven Wärtsilä 18V50SG RICE Generator sets. In addition to its smaller size, which is more closely matched to ENO's revised projected capacity need, the RICE Alternative has several benefits not offered by the CT. It has on-site black-start capability, lower emissions, uses far less water in its cooling process, and operational flexibility. The anticipated cost of the RICE Alternative is $210 million, and, if approval is granted by October 2017, the unit would be in commercial operation by approximately October 2019. In the Supplemental Application, ENO also advised the Council that the expected cost of the CT had increased by

$16 million, due to delays. If the Council approved the CT by the end of October 2017, it could be operational by approximately November 2020.

After filing its Initial Application to build NOPS, and throughout the application process, ENO participated in multiple meetings with community groups, neighborhood associations, and other civic organizations to discuss issues surrounding NOPS, including several meetings in New Orleans East.[38] Council Resolution Nos. R-16-506 and R-17-426 establishing the procedural schedules for ENO's applications have 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.

In Resolution No. R-16-506 issued on November 3, 2016 setting the procedural schedule for the consideration of ENO's initial application for approval to construct NOPS, the Council clearly articulated its intention to afford meaningful public involvement in the decisional process:

> [T]he Council intends to provide the residents of the City of New Orleans with an open and transparent process that will allow for multiple opportunities for the public to communicate its views to ENO and the Council as they relate to the construction of the proposed project….[39]

In that resolution, the Council also required ENO to make a supplemental fling to address certain environmental concerns; created an opportunity for Intervenors to file testimony; required at least two public outreach meetings; provided for a public hearing; and established a mechanism for interested persons to receive email notice of any public meetings or hearings concerning the NOPS application.

---

[38] Cureington-7 at 87:11-13.
[39] Resolution No. R-16-506 at 8.

The following parties intervened in the docket examining the NOPS proposal:

- Alliance for Affordable Energy
- PosiGen
- Air Products and Chemicals, Inc.
- Deep South Center for Environmental Justice, Inc.
- New Orleans Cold Storage & Warehouse Co. Ltd.
- Gulf States Renewable Energy Industries Association
- Sierra Club
- 350 Louisiana - New Orleans

After receiving updated load forecasts that raised questions about the size of the resource needed, ENO filed a motion to suspend the procedural schedule.[40] ENO sent an email to its customers explaining that the Company had requested to temporarily suspend the procedural schedule in the docket so that it could evaluate the implications of the updated load forecast. In April 2017, ENO sent an additional email updating customers about ENO's progress and its investigation into a smaller alternative resource.

When ENO filed its Supplemental Application, the Council adopted Resolution No. R-17-426, which established a modified procedural schedule to examine the revised proposal. This resolution required ENO to conduct no less than five well-advertised public outreach meetings (one in each Council district) and for its Council Utilities Regulatory Office to conduct one public meeting on ENO's Application in the Council chambers. In total, ENO has held at least 21 public meetings regarding NOPS, including several meetings in New Orleans East.[41] Notices

[40] Entergy New Orleans, Inc.'s Motion to Suspend the Current Procedural Schedule Temporarily and to Set Date for Follow-Up Status Conference, Docket No. UD-16-02 (Feb. 14, 2017).

[41] Cureington-7 at 87:2-17, 90:1-16; Rice-4 at 17:10-20. Report Regarding Public Outreach Meetings, Docket No. UD-16-02 were filed on Dec. 22, 2016, Aug. 17, 2017, Aug. 23, 2017, Sept. 12, 2017, and Oct. 4, 2017.

for the meetings and handouts provided at the meetings were available in English, Spanish and Vietnamese in order to further participation by affected communities.[42]

In addition to the public meetings, parties and intervenors to this proceeding were given the opportunity to file written testimony, conduct extensive discovery, including depositions; and in December 2017, a five-day public hearing was held to examine ENO's NOPS application, and the matter is now before the Council for its consideration.

Argument

I. **WHETHER ENO'S ANALYSIS OF NEED IS SUFFICIENT TO JUSTIFY AN INVESTMENT**: ENO has sufficiently demonstrated a critical need for a generation resource to be built in New Orleans.

ENO has presented a *prima facie* case that it needs to build or acquire generation capacity in New Orleans in order to maintain reliable electric service in the City. ENO customers are presently at risk of significant electrical outages of potentially long duration and such risk will persist until some form of corrective action is taken by either the addition of generation in the eastern section of ENO's service area, or the installation of a significant amount of timely new transmission additions.

A. **WHETHER ENO HAS DEMONSTRATED A CAPACITY NEED**: A capacity need does exist and must be addressed, though ENO has overestimated the need.

The Advisors have carefully reviewed all evidence presented by the Company, by Air Products, by the Joint Intervenors, and have performed our own analysis, and have reached the conclusion that there is a capacity need that ENO needs to fill, and that it is of sufficient size to

[42] Cureington-7 at 90:8-10.

warrant an investment in long-term capacity rather than relying upon short-term capacity acquisitions, even though the Advisors do agree that ENO has overestimated its capacity need.

ENO has submitted evidence in this case, including documentation supporting its load forecast, that it has an overall need for approximately 99 MW of capacity by 2026, growing to 248 MW by 2036.[43] Further, ENO argues that some of the capacity it already has is mismatched to its need, so that even though its overall capacity need is 248 MW over the planning horizon, it has a peaking and reserve capacity deficit of approximately 342 MW on average throughout the 20-year planning horizon.[44] In addition, ENO witness Cureington states that ENO's location within the Amite South and DSG load pockets, where old generators are being retired, heightens the need for local generation.[45] Thus, ENO argues, the greatest need is for the addition of peaking and reserve capacity to its portfolio.

The Company's load forecast underlying its projected capacity need has been an issue of contention in this case. ENO's load forecast has been decreasing in recent years, and the Joint Intervenors argue that ENO has repeatedly overestimated customer need for the proposed gas plant.[46] However, Joint Intervenors witnesses have also stated that they do not challenge the underlying fundamentals of ENO's load forecast, nor do they provide a load forecast of their own as an alternative to ENO's load forecast.[47] The Advisors also do not dispute the underlying methodology of ENO's load forecast. The primary concerns articulated by the Joint Intervenors relate not to the underlying load forecast methodology but to two other issues: (1) that the load forecast has been decreasing over time, which the Joint Intervenors appear to believe is due to

[43] Cureington-5 at 7:10-8:3; Rice-3 at 4:23-5:4.
[44] Cureington-5 at 7:10-8:3; Rice-3 at 13:1-14:21.
[45] Cureington-5 17:16-19:2.
[46] Wright-2 at 9:1-11:6.
[47] Hr'g Tr. 12/19/17, 21:22-25; Hr'g Tr. 12/21/17, 21:2-10; Hr'g Tr. 12/19/17, 23:16-19.

profit-seeking activity by the utility; and (2) that ENO has not sufficiently decreased its load forecast to reflect the anticipated future reductions in load due to DG and to the Council's Energy Smart energy efficiency program and the 2% DSM Goal.

With respect to the nature of the decreases in load over time, Joint Intervenors witness Dr. Wright, who does not appear to have any expertise whatsoever in preparing or reviewing load forecasts or any experience at all in the energy industry,[48] opines that ENO has "a pattern of repeated overestimations in its load forecast without explanation."[49] She argues that ENO has failed to explain why its load forecast decreased between the 2015 Final IRP forecast and the forecast in its Initial Application, and why it declined again in the new load forecast ENO provided in February of 2017 that led ENO to file its Supplemental Application.[50] Dr. Wright then leaps to the conclusion that such repeated overestimations and failure to explain the rationale of decreasing forecasts indicate that ENO is either incapable or unwilling to properly calculate how much electricity will be needed in New Orleans, that it is arbitrary, and that one can infer that ENO's goal may not be meeting customer need for electricity, but instead meeting a bottom line for profit.[51] Dr. Wright apparently does not understand the fundamental nature of load forecasts, and has either failed to read the testimony provided in this case or has failed to understand it. ENO witness Cureington clearly explains in his Supplemental and Amending Direct Testimony what caused the changes from ENO's prior load forecast to the updated forecast.[52] Moreover, the nature of a load forecast is to predict the future; there will always be some over- or under-estimation, simply because no one can predict the future with great

[48] *See* Wright-1, Exhibit 1, *Curriculum Vitae of Beverly L. Wright*.
[49] Wright-2 at 9:12-14.
[50] Wright-2 at 9:14-22.
[51] Wright-2 at10:18-11:4.
[52] Cureington-5 at 8:10-9:8.

precision (especially where consumption is partially dependent upon future weather conditions). The goal is to make a prediction based on known data and reasonable assumptions that can reasonably be used for planning purposes.

ENO, like most utilities, routinely updates its load forecasts as part of its basic business planning for the purposes of updating its financial plans, sales forecasts, and financial models and to update their assessments of long-term capacity needs and long-term transmission planning.[53] Mr. Cureington explains that the decrease reflected in the updated load forecast provided in February 2017 was caused primarily by a decline in projected sales among the residential and commercial customer classes, which ENO estimates is approximately 90% due to a decline in residential and commercial usage per customer ("UPC").[54] He explains that while the Company continues to experience growth in the total number of customers served, the decline in UPC more than offset that growth in 2016.[55] He also explained that projected industrial class peaks increased slightly but that projected governmental class sales and peak load is forecasted to be lower than in the prior forecast due to delays and modifications associated with the new Veterans Affairs hospital project.[56] In addition to this explanation, Mr. Cureington attached to his testimony the actual load forecast update and supporting documentation.[57] The Advisors believe that Mr. Cureington has sufficiently explained why the load forecast decreased and believe that it was appropriate for ENO to provide the updated load forecast information to the Council and the parties as soon as it was available.

[53] Cureington-5 at 6:4-11.
[54] Cureington-5 at 8:10-15, 9:6-8.
[55] Cureington-5 at 8:15-9:1.
[56] Cureington-5 at 9:1-6.
[57] Cureington-5, Exhibits SEC-10 and SEC-11 (both HSPM).

The Advisors do observe, however, that the revised load forecasts illustrate a general downward trend in expectations of how load will grow over time. The forecast in ENO's Initial Application was an overall need of approximately 134 MW of capacity by 2020 and up to 205 MW by 2030,[58] which, compared to the 2015 Final IRP load forecast, showed a near-term increase in the forecasted total load requirements followed by a slower average annual growth.[59] By 2030, the forecasted total load requirements in the Initial Application is [………………] lower than that which was forecasted in the 2015 Final IRP.[60] By 2035, it is […………….] lower than the 2015 Final IRP.[61] The updated load forecast first shared in February 2017 and relied upon in the Supplemental Application then further reduced the load forecast by an additional 3.4% or 40 MW per year.[62] The forecasted total load requirements in the Supplemental Application, by 2030 is [……………..] lower than that which was forecasted in the 2015 Final IRP, and by 2035, it is [………………] lower than the 2015 Final IRP.[63] Although ENO argues that there is still a need sufficient to justify its 226 MW CT Alternative,[64] the Advisors believe that the significant reduction in projected total load requirements since the 2015 Final IRP, where a 250 MW CT in 2019 was selected as part of the preferred portfolio, would strongly suggest that 226 MW may be greater than the optimal size for the proposed peaking plant on a capacity need basis.[65]

With respect to the type of capacity needed, the Joint Intervenors argue that ENO does not need to balance each different type of capacity (baseload, load following, and peak), which

---

[58] Cureington-5 at 7:3-6.
[59] Rogers-1 at 6:17-7:1.
[60] Rogers-2 at 7:1-3.
[61] Rogers-2 at 7:1-3.
[62] Cureington-5 at 3:12-18.
[63] Rogers-2 at 8:13-15.
[64] Cureington-5 at 11:10-12:14.
[65] Rogers-1 at 9:3-6.

they believe are, to an extent, interchangeable.[66] Rather, the Joint Intervenors argue the parties should only be discussing the total capacity deficit or surplus.[67] Air Products presents a more nuanced version of the argument, noting that the evaluation of what type of capacity is needed should only influence the type of capacity installed when an overall need has been identified, and should not determine the amount of capacity to be installed.[68] As a general matter, the Advisors agree with Air Products that it is appropriate to consider what type of capacity is needed only when an overall capacity need is identified. The Advisors believe that ENO has identified a capacity need and has demonstrated that the specific type of capacity needed is peaking capacity, and thus conclude that it is appropriate and reasonable for ENO to pursue peaking capacity at a level sufficient to meet the overall capacity need when added to ENO's existing resources.

The Joint Intervenors further argue that ENO failed to properly decrease its load forecast to reflect (1) ENO's own planned solar investments; (2) reasonable expectations of rooftop solar installations; and (3) the Council's 2% DSM Goal.[69] The Advisors believe that a capacity need does continue to exist even when the Council's 2% DSM Goal is accounted for, even though the Advisors agree that ENO failed to incorporate reasonable assumptions regarding the level of DSM that could be achieved in New Orleans into its analysis.

Joint Intervenors witness Dr. Stanton argues that properly accounting for ENO's own planned solar investments reduces ENO's claimed capacity deficit from 99 MW in 2026 to 49 MW.[70] Dr. Stanton bases this conclusion on ENO's announcement that it is planning to procure 100 MW of utility-scale solar resources that will come online in 2020 and half of which MISO

[66] Stanton-1 at 9:11-11:1.
[67] Stanton-1 at 9:15-17.
[68] Brubaker-1 at 6:10-22; Brubaker-2 at 7:7-13.
[69] Stanton-1 at 6:7-11.
[70] Stanton-1 at 6:7-8.

credits toward capacity, which she believes would result in a 50 MW reduction in ENO's capacity need.[71] However, the Advisors note that upon cross-examination, Dr. Stanton admitted that she does not know the location of any of the potential 100 MW of renewables.[72]

ENO states that while ENO remains committed to adding up to 100 MW of solar, the timing and location of those resources are still uncertain.[73] ENO argues that NOPS has been identified as the best alternative to meet the Company's long-term overall capacity deficit, including the substantial need for a local peaking and reserve resource that would provide the benefits ENO discusses with respect to NOPS.[74]

Dr. Stanton also argues that ENO's assumption that the number of small-scale solar systems in New Orleans would [……………………………….] is unreasonably conservative and leads it to overstate its need for capacity.[75] She states that continuing the linear growth trend in behind-the-meter solar installations from [……………] out to 2036, would result in [……... ……….] of additional, non-coincident peak load reduction by 2036.[76] However, in cross-examination, Dr. Stanton admitted that she had not performed any analysis that supports this trajectory of behind-the-meter solar growth in New Orleans,[77] that she did not perform an analysis with respect to the duration that behind-the-meter or utility scale battery storage could provide capacity when needed,[78] and that she did not perform an analysis of the potential costs of either behind-the-meter solar or utility scale battery storage over the 20-year planning horizon,

---

[71] Stanton-1 at 11:8-14.
[72] Hr'g Tr. 12/21/17, 22:4-15.
[73] Cureington-7 at 49:15-16.
[74] Cureington-7 at 49:4-9.
[75] Stanton-1 at 16:3-8.
[76] Stanton-1 at 19:9-11.
[77] Hr'g Tr. 12/21/17, 24:11-15.
[78] Hr'g Tr. 12/21/17, 25:17-22.

and had not analyzed the capacity that either could provide.[79] Given her lack of analysis to support her projections of behind-the-meter solar growth in New Orleans, the Advisors are not persuaded to rely upon her calculation of how much capacity is likely to be available through behind-the-meter solar.

ENO argues that the rate of new rooftop solar installations in New Orleans will decline significantly.[80] ENO explains that unique circumstances led to the remarkable growth of rooftop solar in New Orleans over that last few years and that it is uncertain whether customers who do not yet have rooftop solar will be willing to pay more than past customers as those unique circumstances change.[81] ENO explains that current rooftop solar customers have benefitted from a full retail rate credit in the net metering tariff, as well as state and federal tax credits that, combined, would cover up to 80% of the cost of a typical rooftop solar system.[82] However, ENO points out, the refundable state tax credit was scheduled to end December 31, 2017, that installations in New Orleans have been declining since the state legislature changed policies in 2015, and going forward, the Company expects that the number of new installations will continue to decrease to a *de minimis* point following expiration of the state tax credit at the end of 2017 and the phase-down of federal tax credits that will begin in 2020, all of which will ultimately significantly reduce the subsidies to customers and installation companies.[83] ENO states that average monthly interconnections in New Orleans have fallen by approximately 86% in 2017 compared to their peak in 2013, and that Dr. Stanton completely missed the important

---

[79] Hr'g Tr. 12/21/17, 24:24:22-25:16.
[80] Cureington-7 at 38:14-15.
[81] Cureington-7 at 38:15-18.
[82] Cureington-7 at 39:5-7.
[83] Cureington-7 at 39:8-40:6.

circumstances unique to the recent slowing of growth in rooftop solar adoption in New Orleans.[84]

ENO argues that the Council's 2% DSM Goal is not likely to be achievable, and even if it were achievable, it would not be cost-effective.[85] ENO explains that it retained Navigant Consulting, Inc. ("Navigant") to assess the upper bounds of energy efficiency potential that could be achieved by ENO in a cost-effective manner, to evaluate whether the 2% DSM Goal is theoretically possible, regardless of cost, and to estimate the costs associated with achieving that goal and sustaining the 2% level over the study period.[86] ENO included the Navigant report in its testimony.[87] The Navigant report concluded that "with a comprehensive portfolio of efficiency measures, aggressive marketing and incentives, and realistic assumptions, ENO could cost-effectively reduce forecast load by roughly 17% over the next 20 years, an average of 0.85%/year."[88] Navigant further concluded that, while it achieved 2.0% in one year using unrealistic assumptions and including measures that are not cost-effective, even then it is not sustainable and the level of savings declines after 2023 due to market saturation of the measures.[89] Navigant further added that "the high ramp rate of this scenario is likely unrealistic and would be difficult to achieve under real-world conditions."[90]

ENO points out that in the scenario where Navigant concluded that using unrealistic assumptions could generate the 2% DSM savings for 2023, with the savings decreasing thereafter, Navigant reached the conclusion that the cost of achieving this scenario would exceed

[84] Cureington-7 at 40:9-14.
[85] Cureington-5 at 36:8-9.
[86] Cureington-5 at 36:9-16.
[87] Cureington-5, Exhibit SEC-14.
[88] Cureington-5, Exhibit SEC-14 at 3.
[89] *Id*. at 3, 13, and 21.
[90] *Id*. at 3.

$1.4 billion over the 20-year period.[91] Joint Intervenors witness Stanton states that ENO's assumed costs of energy savings are more than double that of states with 2% annual incremental savings, that ENO is assuming an exorbitant amount of spending on additional DSM, which handicaps that resource in the analysis.[92] Dr. Stanton states that incorporating the 2% DSM Goal would lower peak load by [……………]. However, Dr. Stanton admitted upon cross-examination that the actual level of savings from DSM programs is uncertain, and she cannot guarantee any particular level of savings.[93] She also admitted that she had not conducted any analysis of the DSM potential in New Orleans.[94] Dr. Stanton further admitted that if a load forecast is decreased to account for a particular DSM forecast and that DSM forecast does not materialize, customers would be exposed to capacity market price risks.[95]

In addition to not incorporating the 2% DSM Goal into its reference case, a review of ENO's calculations indicates that while ENO accounted for the effects of existing DSM programs for Program Year 6 (12 months ended March 2017), it did not incorporate any reductions in the load requirements for future DSM programs.[96] The Advisors' analysis shows that if the 2% DSM Goal is taken into account in the load forecast, the projected capacity shortfall declines to [………………] by 2030 and then increases to [………………] by 2036.[97] It is important, however, to note that while ENO has submitted evidence backed by a study performed by Navigant that the 2% DSM Goal is not achievable, and no party has put evidence into the record that demonstrates that the 2% DSM Goal is achievable, the Advisors believe that

[91] *Id*. at 5.
[92] Stanton-1 at 34:12-35:3.
[93] Hr'g Tr. 12/21/17, 21:11-15.
[94] Hr'g Tr. 12/21/17, 22:20-24.
[95] Hr'g Tr. 12/21/17, 28:7-13.
[96] Rogers-1 at 10:1-5; Prep-1 at 30:2-5.
[97] Rogers-2 at 13:7-11.

it is reasonable, in light of the goal, to expect the kWh savings from DSM to grow beyond the Program Year 6 kWh savings assumed in ENO's reference case, and thus, the Advisors believe that the ultimate capacity need will likely be smaller than what ENO has projected. Accordingly, a capacity need exists, albeit smaller with consideration of DSM growth, and the Advisors believe that a long-term investment in generation capacity is justified.

In opposition to assumptions of reductions in its load forecast, ENO also argues that the Company's load forecast (1) does not include any adjustments for potential load increases that could materialize if the economy grows more strongly than forecast, which could increase growth in customer count, load, or both; (2) does not include the potential for adoption by customers of electric vehicles ("EVs") that would increase the Company's load as those vehicles' batteries are charged; and (3) that it does include the assumption that existing rooftop solar will continue providing the same level of load reduction over the planning horizon, which does not account for the degradation of solar panels over time and assumes customers keep their systems in good operating condition.[98] Therefore, the Company argues making further assumptions such as those recommended by the Joint Intervenors would be extremely risky.[99] ENO notes that the need for further generation could also arise from unanticipated reductions in the rated capacity of existing resources.[100]

Moreover, the Advisors' analysis demonstrates that ENO has employed inconsistent peak load assumptions as between its transmission studies and economic studies when considering the amount of DSM peak load reductions which would occur with the continued implementation of the Council's 2% DSM Goal and the appropriate capacity factor of any potential solar

[98] Cureington-7 at 53:9-54:4.
[99] Cureington-7 at 54:3-8.
[100] Cureington-7 at 54:9-10.

generation.[101] Such inconsistent assumptions can affect the actual load to be served in the transmission studies in the range of 48.1 MW to 63.1 MW over the period analyzed.[102] Thus, there is significant uncertainty as to by how much ENO's load forecast can reasonably be reduced. Reliable electric service is a critical need, the consequences of failing to ensure reliable service -- in this case the potential for cascading outages of long duration affecting as many as 49,000 customers -- are likely to be worse than the consequences of investing in slightly too much capacity. To be clear, the Advisors do not recommend "gold-plating" the system with extra capacity that will not be needed. Rather, by recommending the RICE Alternative, the Advisors recommend the installation of an amount of capacity that allows for a reasonable margin of error, based on the data and information known at this time. It is generally not possible to match capacity with load requirements precisely, any given utility will be somewhat long or short on capacity in any given year, and using the capacity markets as a short-term fix to true up any such minor imbalances is reasonable. However, capacity market prices are wildly variable, and because of this, the Advisors find that it is prudent to try to match the capacity with the load requirement as closely as is reasonably possible.[103]

In consideration of the foregoing, the Advisors conclude that the evidence indicates that ENO has an immediate and future need for capacity and that need is not mitigated even if the Council's 2% DSM Goal is achieved. Further, the Advisors believe that it would not be appropriate to rely on the MISO annual planning resource auction ("PRA") to meet ENO's long-term resource needs. Accordingly, the Advisors believe the capacity need in combination with the reliability needs warrants an investment in long-term capacity.

---

[101] Vumbaco-1 at 6:12-15.
[102] Vumbaco-1 at 6:15-17.
[103] Rogers-1 at 32:1-8.

B. <u>WHETHER ENO HAS DEMONSTRATED A RELIABILITY NEED</u>: ENO has demonstrated a critical reliability need for generation resources in Orleans Parish to maintain the reliability of the electric grid and avoid cascading outages impacting most of the city.

ENO has a current and critical need for generation resources in Orleans Parish to assure reliability and avoid an unacceptable risk of cascading outages of long duration. That need exists today and will continue to exist until generation is constructed in New Orleans. All parties appear to be in agreement that ENO currently faces reliability risks since the deactivation of Michoud in 2016.[104]

New Orleans is located in the constrained DSG region of the power system. DSG has unique geographical limitations (*i.e.*, it is largely surrounded by water) and it contains highly concentrated electrical loads that are highly reliant on local generation to maintain reliability, and limited import capability, making it a "load pocket."[105] Since the deactivation of Michoud, however, all of the units ENO relies on for reliability are located outside Orleans Parish.[106] (ENO also notes that many of the existing units in DSG are old and may soon be retired.[107]) In other words, the City is entirely dependent upon transmission lines to meet reliability requirements and demand. ENO witness Charles Long testified that New Orleans is greatly affected by reliability because it is located in the constrained DSG region of the power system.[108]

New Orleans is located in a geographical and electrical peninsula bordered by water on the north, east and south. Almost all electrical energy is imported into the City from the west, primarily through East Jefferson Parish via the transmission grid, while a small amount of

[104] C. Long-3 at 3:11-15.
[105] C. Long-1 at 3:11-15; C. Long-2 at 3:14-16.
[106] C. Long-1 at 3:15-18.
[107] C. Long-2 at 8:5-7.
[108] C. Long-1 at 3.

electric energy is transported through the very limited transmission capability from the Slidell area over the open waters of Lake Pontchartrain.[109] The existing transmission facilities serving the City traverse a limited set of viable transmission corridors across wetlands and generally poor soil conditions through an area heavily congested with industrial, commercial, and residential structures.[110] This geography limits the amount of transmission facilities available to serve New Orleans. No party has refuted this point. Without a local generation resource, the City in general, and New Orleans East in particular, is entirely dependent on the set of existing transmission lines situated in a relatively small geographical area. ENO says that the loss of even a portion of these transmission facilities delivering energy from the West into the City would likely prevent the Company from serving its entire load."[111]

As such, the geographical limitations and the fact that the region has highly concentrated electrical loads makes New Orleans reliant upon local generation to maintain reliable service.[112] As Mr. Long notes, without a local source of energy, the City in general, and New Orleans East in particular, is entirely dependent on the set of existing transmission lines situated in a relatively small geographical area. Because of this lack of geographic diversity, it can reasonably be expected that all lines, save perhaps the single line from Slidell, would be vulnerable to similar outages and operational challenges.[113] ENO witness Charles Long testifies that following the 2016 deactivation of Michoud generation Units 2 and 3, all of the generation that ENO currently depends on for reliability are located outside of Orleans Parish.[114] There is no substantiated dispute from any party regarding these facts. The upshot of these facts is that New Orleans faces

[109] C. Long-2 at 4.
[110] C. Long-2 at 4-5.
[111] C. Long-2 at 5:7-9.
[112] C. Long-1 at 3.
[113] C. Long-2 at 5.
[114] C. Long-1 at 3.

a critical and unacceptable reliability risk. Mr. Long testified that "without a local resource, the loss of even a portion of these transmission facilities delivering energy from the West into the City would likely prevent the Company from serving its entire load." [115]

In the DSG region, the simultaneous loss of a generation resource and a transmission element often results in voltage and thermal constraints which cannot be mitigated without the commitment of another local unit, particularly since many of the generators in the region have long start-up times.[116]

Because of the unique configuration and system constraints, all DSG generating units, including Michoud when it was operational, are committed as "Voltage and Local Reliability" resources to ensure that enough capacity exists in the region to maintain reliability.[117] Similarly, prior to ENO's membership in MISO, Michoud was a "reliability must run" unit, meaning that it was essential to the maintenance of system reliability, even if some other unit might be more economic in terms of energy costs.[118]

The deactivation of Michoud has left ENO with a critical need for generation in order to keep the system from collapsing in the event of certain contingencies. According to ENO witness Charles Long, without construction of incremental dispatchable local generation (*i.e.*, NOPS), the City and DSG region will experience a degradation in system reliability. New Orleans faces a risk of cascading outages with loss of electric load served from most of ENO's

---

[115] C. Long-2 at 5.
[116] C. Long-1 at 4:11-15.
[117] C. Long-1 at 4:9-5:7.
[118] Movish-1 at 9:19-10:11

substations. More than 30 miles of transmission lines would be overloaded, and 49,000 ENO customers could lose power extended periods of time, particularly in New Orleans East.[119]

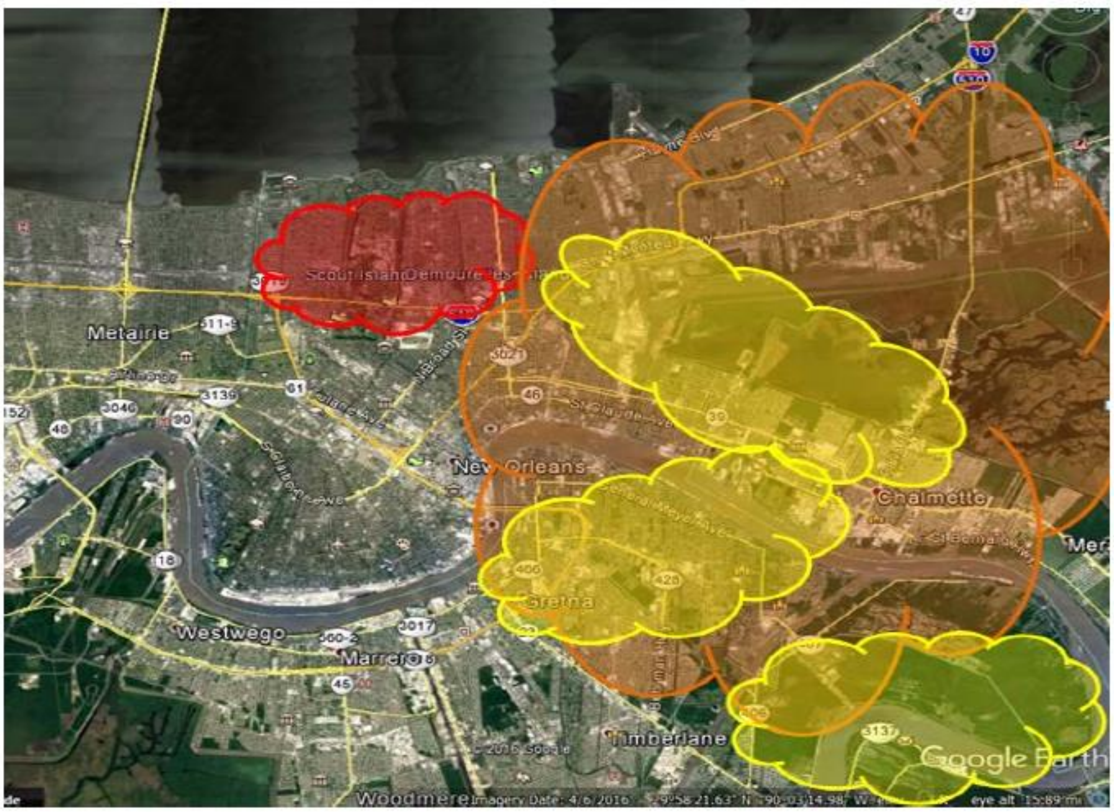
Additionally, ENO would not be in compliance with the standards set by the North American Electric Reliability Corporation ("NERC"). ENO is presently at risk for two NERC contingencies in particular. Of greatest concern, ENO is at risk of a "P6" contingency, which involves loss of multiple transmission facilities. In order to fully appreciate the existing critical reliability need that must be addressed, the record shows that without affirmative action (*i.e.*, construction of new local generation or transmission upgrades), if a NERC "Category P6"[120] event occurred, New Orleans is at risk of "[c]ascading outages resulting in the loss of the electrical load served from twelve of the fourteen ENO substations operating at 115 kV. This would result in an outage to approximately 49,000 ENO customers and given the nature of the event, the outage could prevail for an extended period of time."[121] A P6 event is the loss of a transmission facility followed by system adjustments, followed by the loss of an additional transmission facility. A P6 contingency simulates operational conditions that would occur during a planned (maintenance outage) or unplanned outage to a transmission facility followed by an unplanned outage to an additional transmission element.[122]

ENO witness Charles Rice included detailed discussions and visuals in his testimony demonstrating what would happen in the event of a P6 NERC contingency under several scenarios. The following picture, which appears as Figure 1 of Charles Rice's Supplemental &

[119] C. Long-1 at 7:7-15.
[120] C. Long-1 at 7 citing NERC TPL-001-4; Table 1, Page 9.
[121] C. Long-1 at 7.
[122] *Id*.

Amending Direct Testimony[123] and also in an attachment to Charles Long's rebuttal testimony illustrates what would happen if a category P6 NERC contingency were to occur in 2019 under the Transmission Alternative that incorporated the Council's 2% DSM Goal.[124] The area circled in red is the location of the severely overloaded transmission line.[125] The overload of that line would result in similar severely overloaded lines in the areas circled in yellow, followed by cascading outages and rapid load shedding (loss of service) in the areas circled in orange.[126]

Figure 1



---

[123] Rice-3 at 6:5-6

[124] C. Long-3, Exhibit CWL-8 at 4.

[125] C. Long-3, Exhibit CWL-8 at 4.

[126] C. Long-3, Exhibit CWL-8 at 4.

Approximately 49,000 customers in New Orleans would be affected by this event and it would take several days or longer to restore power to them due to the nature of the equipment outage that would create this type of event.[127]

ENO explains that it is not presently in violation of NERC's standards because it has presented its corrective plan to NERC (the construction of NOPS) and is diligently pursuing approval of the NOPS as part of that plan.[128] However, if NOPS is not approved, ENO will have to make extensive transmission upgrades, many of which face serious constructability challenges.[129] And ENO's current solution to such a contingency, at least until it has an additional resource on its system, is load shedding,[130] *i.e.* deliberately curtailing service to a portion of its customers in order to prevent the collapse of the entire system.

MISO has confirmed ENO's own analyses of the long-term reliability risks it currently faces, including the possibility of long-duration cascading outages. MISO's recent MTEP17 (MISO's 2017 Transmission Expansion Plan) report identifies the same critical contingency that ENO identified in its analysis, and reports the same risk of severe overloads resulting in cascading outages. At a recent UCTTC meeting, MISO reported on ongoing operational challenges of operating the grid in the DSG load pocket, emphasized the importance of having local generation in the City and indicated that Michoud is a good location for such generation.[131]

ENO argues that construction of incremental dispatchable local generation is the *only* viable option to address the reliability problems facing the New Orleans area. This approach not

---

[127] C. Long-1 at 7:8-11.
[128] Hr'g Tr. 12/15/17, 129:24-125: 3.
[129] C. Long-3 at 4:1-5:2.
[130] Hr'g Tr. 12/15/17, 127:9-14.
[131] C. Long-3 at 8:23-9:17.

only addresses the current risk of uncontrolled cascading outages in the most expeditious manner,[132] 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.[133]

Resorting to transmission upgrades alone won't, as a practical matter, resolve the reliability issues for the reason that there are significant constructability problems. ENO expressed "serious doubts" about its ability to implement the outages necessary to make the required upgrades. The process would be very long and is far more risky than building generation on a site ENO already owns.[134] First, it would take far longer to plan and implement transmission upgrades than to construct NOPS.[135] If ENO could get the outages necessary to make the upgrades, they would last many months while upgrades were being completed.[136] Additionally, there is a serious risk of a P6 event occurring while the upgrade are being done because of the constraints on the system.[137] ENO witness Charles Long explained:

> "[C]onstructing transmission in the DSG area is extremely challenging and costly for multiple reasons and thus attempting to do so would expose the City to the risk of cascading outages beginning immediately and lasting until such a time when all upgrades are completed. I cannot stress enough that taking these transmission facilities out of service to upgrade them will be extraordinarily difficult 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.
>
> Moreover, even assuming that the Company would be able to construct the upgrades at some point in the future given enough time and money, it is undisputed that ENO's customers would bear the current and persisting risk of cascading outages in the meantime; and even if constructed, these upgrades would

---

[132] Movish-1 at 20:16-17, 32:10-33, 51:5-9; C. Long-2 at 2:8-16, 13:7-8; Vumbaco-1 at 21:8-11; Hr'g Tr. 12/15/17, 124:22-24.
[133] C. Long-3 at 8:6-7.
[134] Hr'g Tr. 12/15/17, 171:13- 172: 2.
[135] Hr'g Tr. 12.15/17, 197:7-198:3.
[136] Hr'g Tr. 12/15/17, 193:19-194:5.
[137] Hr'g Tr. 12/15/17, 208:9-25.

> not provide storm support or expedite storm restoration, would not afford any reliability margins in the transmission network to add new customers or to accommodate unexpected changes to the transmission system, would not significantly reduce line loading in the DSG area, would not contribute to any incremental dynamic reactive power in New Orleans, and would leave customers exposed to many of the operational reliability issues currently faced today. Simply put, the transmission upgrades are not an adequate solution to the suite of current reliability issues facing New Orleans based on my experience as a transmission planner."[138]

Similarly, DSM and solar do not resolve the reliability issue. At times, these resources provide zero capacity, and so cannot be relied on for purposes of meeting NERC criteria.[139]

ENO also says that having a local resource would also reduce stresses to the transmission system that result in operational issues such as the difficulty in obtaining outages for construction or maintenance because of reliability constraints that cannot be mitigated without risking service to ENO's customers.[140]

Air Products witness Dauphinais, without any support, evidence or substantive argument, asserts that ENO has not reasonably demonstrated there is a local thermal, voltage, reactive power or resource adequacy need for the CT.[141] Dauphinais' argument seems to focus on whether there is some other, hypothetical resource alternative in the DSG that could reduce or eliminate the need for transmission upgrades if NOPS is not approved. Moreover, in his Additional Direct Testimony, dated October 16, 2017, Air Products witness Brubaker recognizes that ENO's updated studies show a long-term capacity need of approximately 99 MW by 2026 and up to 248 MW by 2036.[142] What this means is that the City is *presently at risk* of wide-spread, long-lasting cascading outages, and this risk will increase over time if not immediately

[138] C. Long-3 at 3:8-22. *See also* Tr. 12/21 181:18-182:4.
[139] Hr'g Tr. 12/15/17, 136-157.
[140] C. Long-2 at 6:18-7:6.
[141] Dauphinais-1 at 4.
[142] Brubaker-2 at 5.

addressed. Mr. Brubaker also recognizes an ENO-forecasted near-term capacity need of less than 100 MW.[143]

Not only did Mr. Dauphinais fail to support his assertion, the testimony of Joint Intervenor witness Luckow rebuts this uncorroborated claim in response to the question: **Is transmission security absent the NOPS plant dependent on additional transmission system reinforcement in the DSG load pocket area?** Mr. Luckow answers: "Yes. The responses to discovery indicate that absent transmission reinforcement of existing circuits, there would be violations of transmission security—thermal or voltage deficiencies on the transmission grid."[144]

In his 2016 testimony, Luckow argues that the reliability need for local generation is overstated.[145] He argues that there is "substantial capacity in the load pocket" but only if certain transmission improvements are made.[146] However, neither Mr. Luckow, nor any of the other Joint Intervenor witnesses, did any analysis to determine the feasibility of actually completing the transmissions upgrades. Without the requisite transmission upgrades, only a limited amount of the capacity in the load pocket can be delivered to New Orleans under ideal conditions. Under the types of contingency conditions that reflect less than ideal conditions, this capacity cannot be delivered to New Orleans.

Intervenor Witness Fagan argues that reliability associated with resource adequacy can be maintained through meeting MISO Zone 9 capacity obligations, which do not include a requirement for New Orleans generation.[147] Reliability associated with transmission system

---

[143] *Id.* at 6; *see also* Brubaker-3 (HSPM).
[144] Luckow-1 at 22 noting ENO Response to Discovery to Advisors 1-19d (designated CEII confidential).
[145] Luckow-1 at 5.
[146] Luckow-1 at 21
[147] Fagan-1 at 33:11-16.

security can be ensured by reinforcement of existing transmission system elements.[148] He argues that the Ninemile Station is within the DSG load pocket and serves as a source of local dynamic reactive supply, and additional resources can be added.[149] And, he asserts that neither NERC nor MISO reliability standards require ENO to have generation in New Orleans.[150] Fagan may be correct that there is no MISO or NERC rule that states that ENO must have generation in New Orleans. However, that is a false argument. The question is not whether a rule specifically requires local generation, the question is whether ENO can feasibly meet the NERC and MISO reliability requirements without local generation. Fagan admitted on cross-examination that when he prepared his testimony, he had not done any studies to determine the feasibility of outage scheduling for transmission lines into the ENO service area for the next ten years, and that he has never planned or operated transmission in MISO South, so his speculation as to how easily transmission upgrades can be accomplished appears to lack any foundation.[151] He also admitted upon cross-examination that in recommending a transmission-only option with reliance on the MISO capacity market to meet capacity needs, he was not familiar with and did not address or do any analysis of narrow constrained areas within MISO South.[152]

Joint Intervenors witness Stanton argues that ENO could meet its MISO capacity and NERC transmission obligations by purchasing market capacity and that transmission upgrades are less expensive than and provide more resilience than building NOPS.[153] However, Dr. Stanton admitted in cross-examination that she has no training or experience in transmission system planning or utility operations, leaving one to wonder upon what she has based her

[148] Fagan-1 at 33:11-16.
[149] Fagan-1 at 33:17-34:3.
[150] Fagan-1 at 36:2-17.
[151] Hr'g Tr. 12/19/17, 32:3-15.
[152] Hr'g Tr. 12/19/17, 31:10-19.
[153] Stanton-1 at 7:9-11; 35:6-8; 44:1-7.

opinion.[154] Dr. Stanton says that New Orleans needs distribution upgrades and argues that distribution outages are a more serious problem than transmission outages.[155] According to Stanton, because constructing NOPS will not resolve the distribution system problem, it will not help reliability.[156] However, upon cross-examination, Dr. Stanton admitted that she had not conducted any analysis of ENO's distribution system and was forced to agree that investment in the distribution system is not a viable alternative to addressing ENO's capacity needs.[157] It follows that investment in the distribution system will not address ENO's transmission-related reliability needs.

Based on review of ENO's analyses, including Critical Energy Infrastructure Information ("CEII"), the Advisors' agree that as a result of the deactivation of Michoud, ENO faces a present and persistent unacceptable risk of uncontrollable cascading outages of potentially long duration.

Advisor witness Movish testifies that due to the transmission constrained nature of the DSG load pocket, and ENO's transmission system limitations, local generation has been operated historically during high load periods to support system reliability in order to protect against the unplanned outage of external DSG generation and/or transmission, and to provide a local source of reactive power to maintain system voltage within acceptable limits.[158]

Movish reviewed ENO's 2016 Reliability Assessment which reflects the retirement of Michoud Units 2 and 3 without any generation additions in ENO's service territory. Mr. Movish

---

[154] Hr'g Tr. 12/21/17, 11:19-22.
[155] Stanton-1 at 44:8-48:21.
[156] Stanton-1 at 44:8-48:21.
[157] Hr'g Tr. 12/21/17, 27:4-11.
[158] Movish-1 at 9:19-10:11,

concluded that the results of the assessment indicate that after the retirement of the Michoud Units, and without adding any new generation, ENO's system is presently at risk of transmission reliability violations.[159] Because it no longer has a local generating source located in New Orleans, ENO's system has to import all of its power supply over significantly constrained transmission lines. If local generation is not constructed, and transmission upgrade projects are not accomplished, ENO's system will continue to face potentially excessive risks of catastrophic outages. Advisor Witness Rogers similarly recognizes the risk. He states that based on load flow analyses, the Company has identified a current and immediate need for a solution to mitigate the potential risk of outages in New Orleans.[160]

Advisor witness Vumbaco also testified that under the criteria of a NERC P6 contingency, ENO customers are presently at risk of electrical outages of potentially long duration and such risk will persist until some form of corrective action is taken by either the installation of a significant amount of timely new transmission additions, or the addition of generation in the eastern section of ENO's service area.[161]

Mr. Vumbaco further states that ENO may not reasonably take no action and satisfy relevant service reliability standards requirements and assure reliable electric service in New Orleans. ENO must have a plan to correct certain deficiencies in its transmission system under NERC standards. Absent such a plan, ENO and its customers will be placed at significant risk for long duration outages and potential significant loss of customer load. Without some

---

[159] Movish-1 at 14:9-11.
[160] Rogers-1 at 50:14-15.
[161] Vumbaco-1 at 6:7-11.

improvements by ENO in the system, whether by capacity addition, transmission upgrades, or significant load reduction, it will be in violation of NERC standards.[162]

The Advisors agree with ENO that just building transmission is not the appropriate solution to the reliability issue. Given ENO's stated constructability issues and other unknowns concerning ENO's accomplishment of required transmission upgrades needed to mitigate its transmission reliability issues, a transmission-only option (with or without the inclusion of 2% DSM and solar PV capacity), presents significant reliability risk to New Orleans customers.[163]

Notably, none of the Intervenors have presented evidence to the contrary, and none appear to seriously or credibly dispute that there is a serious reliability problem. The disagreement is in how to resolve the problem.

Accordingly, based on the substantial evidence in the record, the Advisors conclude that ENO has demonstrated a critical reliability need for generation resources in New Orleans to maintain reliability of the electrical system and to avoid wide-spread, long-lasting outages impacting most of the City.

II. <u>WHETHER ENO'S CHOICE OF TECHNOLOGY(IES) IS IN THE PUBLIC INTEREST:</u> The construction of the RICE Alternative in combination with the incorporation of renewable technologies and realistically achievable cost-effective DSM potential in ENO's service territory is in the public interest.

In its Supplemental Application, ENO requests that the Council, "Find that the Company's construction of NOPS, either the originally proposed CT or the Alternative Peaker, serves the public convenience and necessity and is in the public interest, and is therefore

[162] Vumbaco-1 at 20:13-21:4.
[163] Movish-1 at 4:6-9.

prudent."[164] The regulatory standard that the Council should employ in its evaluation of ENO's Application is a determination of whether any of the alternatives for Council consideration and their related cost recovery serves the public convenience and necessity and are in the public interest. Should more than one alternative be deemed by the Council to serve the public interest, the Council should determine which such alternative best serves the public interest.[165]

The public interest theory of regulation seeks, in general terms, to protect and benefit the public at large through a balancing of interests in any regulatory decision.[166] With the filing of ENO's Application, the Council must determine whether ENO's proposed construction of either the CT Alternative or the RICE Alternative, or any other alternative such as the transmission-only alternative, and the associated cost recovery, is both necessary and serves the public interest. Put differently, the Council must determine whether any alternative for Council consideration represents an economic and prudent means by which ENO may ensure safe and reliable electric service to New Orleans and whether such an alternative would provide overall benefits to the public.[167]

The Council should not consider any single element of the public interest in isolation. The Council should perform its review of the economic analysis results with an emphasis on the considerations of system reliability and the relative operational benefits and environmental impacts of the RICE Alternative as compared to the CT Alternative. The Council should consider the economic attractiveness of the CT Alternative, the RICE Alternative and the

---

[164] Supplemental and Amending Application of Entergy New Orleans, Inc., for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief, Docket No. UD-16-02, at 27 (July 6, 2017).

[165] Vumbaco-1 at 10:3-7.

[166] Vumbaco-1 at 10:9-17.

[167] Vumbaco-1 at 10:9-17.

Transmission Alternative alongside the risks associated with each alternative.[168] "Risk" in this context may be viewed as the possibility that the outcomes and each associated assumption as modeled therein may not come to pass, the degree to which the modeled outcome may differ from actual outcomes, and the potential adverse effects on the public interest from actual outcomes differing from modeled outcomes.[169]

A. **<u>WHETHER ENO'S SELECTION OF A CT UNIT IS IN THE PUBLIC INTEREST:</u>** ENO has not demonstrated that its CT proposal is in the public interest. While it would comply with applicable environmental regulations, it is a larger investment than the identified need requires and puts ratepayers at risk of overpaying for capacity they do not need.

The CT Alternative is not in the public interest. While it would fully address the identified reliability need over the entire length of the planning period, it would also expose customers to significant economic risks. This occurs because the capacity of the proposed CT unit far exceeds the capacity needs of the Company for most of the planning period, and the Company's analysis of the economics of the CT Alternative are heavily dependent upon its forecast that MISO capacity prices will escalate at an unprecedented rate that would allow ENO to earn significant revenues by selling the excess capacity into the MISO market in order to offset the costs of the CT Alternative to ratepayers. If ENO is incorrect in its forecast that MISO capacity prices will rise to unprecedented levels very quickly, those revenues will not materialize and New Orleans ratepayers will have to bear significantly greater costs than ENO's economic analysis predicts.

Even in its Supplemental Application, filed subsequent to its reduced load forecast, ENO argues that its CT Alternative is the most cost-effective means of addressing ENO's identified

[168] Vumbaco-1 at 24:17-25:16.
[169] Vumbaco-1 at 26:1-6.

long-term planning needs when using ENO's assumptions around capacity prices in MISO.[170] ENO argues that even under a sensitivity analysis using highly discounted capacity price assumptions, the CT Alternative is virtually tied, economically, with other portfolios and should therefore prevail given its significant local benefits.[171] ENO witness Cureington argues that the CT Alternative is the most cost-effective means of addressing ENO's long-term planning needs while considering risk.[172]

ENO witness Cureington ran several economic analyses of the proposed alternatives for meeting the identified need. He conducted AURORA production cost modeling of three reference cases across sensitivities for natural gas and MISO capacity prices.[173] Case 1 was the RICE Alternative. Case 1G was the CT Alternative, and Case 2 was the Transmission Alternative.[174] All three cases include the Business Plan 17 Update (BP17U) forecast of load and commodity prices including the reference CO_2 price forecast, 100 MW of solar resources, continuation of Energy Smart and full deployment of ENO's proposed Advanced Metering Initiative ("AMI").[175] Sensitivities were conducted using low and high gas prices and 60% of the MISO capacity price forecast. The results were then incorporated into the Total Relevant Supply Cost Analysis.[176] The Advisors also requested that ENO run three requested portfolios to model certain assumptions advanced by the Intervenors.[177] Although it was requested that ENO use AURORA's capacity expansion model, the scope of the modeling did not allow that feature to be

[170] Rice-3 at 7:16-20.
[171] Rice-3 at 7:16-20.
[172] Cureington-5 at 5:6-10.
[173] Cureington-5 at 27:1-29:8.
[174] Cureington-5 at 27:1-29:8.
[175] Cureington-5 at 27:1-29:8.
[176] Cureington-5 at 27:1-29:8.
[177] Cureington-3 at 31:18-33:11.

used. Instead, ENO attempted to simulate the results of the capacity expansion feature.[178] Accordingly it conducted AURORA modeling on four portfolios using inputs and assumptions requested by the Advisors on behalf of the Intervenors.[179] The first portfolio (Case 3) evaluates the RICE, the second one (Case 3G) evaluates the CT.[180] The third one (Case 4A) evaluates adding 100 MW solar, and the fourth one (Case 4B) evaluates adding 300 MW of wind.[181] They all included the BP2017U load forecast adjusted for the estimated impact of the 2% DSM Goal, the planned 100 MW of solar, and full deployment of AMI.[182] They also ran the same sensitivities using low and high gas prices and the 60% MISO price forecast.[183] However, ENO argues, the Requested Portfolios included an assumption of attaining the 2% DSM Goal, which is not likely to be attainable, and would not be cost-effective, as is demonstrated by the Navigant report.[184]

Mr. Cureington concludes that the CT Alternative was the most cost-effective option in all three scenarios run with ENO's higher MISO capacity cost assumptions.[185] He concludes that it was also the most cost effective in the scenario with 60% of the ENO MISO capacity cost assumptions where the natural gas prices were also assumed to be low.[186] In the reference and high gas price models with the 60% MISO capacity cost assumption, the CT Alternative was less cost-effective than the Transmission Alternative, but more cost-effective than the RICE Alternative.[187] Mr. Cureington's analysis concluded that the CT Alternative was also the most

[178] Cureington-3 at 31:18-33:11.
[179] Cureington-3 at 31:18-33:11.
[180] Cureington-3 at 31:18-33:11.
[181] Cureington-3 at 31:18-33:11.
[182] Cureington-3 at 31:18-33:11.
[183] Cureington-3 at 31:18-33:11.
[184] Cureington-5 at 35:4-39:6.
[185] Cureington-5 at 28:4-10.
[186] Cureington-5 at 29:1-8.
[187] Cureington-5 at 44:6-15.

cost-effective option in all four Requested Portfolios run with ENO's higher MISO capacity cost assumptions.[188] He further concluded that the CT Alternative was also the most cost effective in the scenario with 60% of the ENO MISO capacity cost assumptions where the natural gas prices were also assumed to be low.[189] In the reference and high gas models with the 60% MISO capacity cost assumption, the CT Alternative was less cost-effective than a solar scenario, but more cost-effective than the RICE Alternative and a wind scenario.[190]

ENO witness Cureington concludes that deploying a dispatchable unit in New Orleans mitigates market and supply related risks, especially as the market reached equilibrium and provides additional local reliability benefits.[191] He states that the CT Alternative is comparable in Total Relevant Supply Costs to the RICE Alternative, but provides additional benefits.[192] In addition, Mr. Cureington also concludes that given that the 100 MW solar portfolio and the 226 MW CT Alternative are virtually tied in terms of Total Relevant Supply Costs, the 226 MW CT Alternative is the better resource for meeting ENO's identified long-term planning needs while considering risk.[193]

ENO also argues that the CT Alternative has certain benefits over the RICE unit -- (1) it provides more capacity in the DSG load pocket, which is needed; (2) it would eliminate all NERC reliability issues over the ten year planning horizon (3) it would create a more effective hedge against market and supply related risks in MISO; (4) it would create larger reliability margins over and above the minimum amount of generation needed for grid stability; and (5) it

[188] Cureington-5 at 33:13-34:2.
[189] Cureington-5 at 34:4-35:3.
[190] Cureington-5 at 45:3-9.
[191] Cureington-5 at 44:15-46:10.
[192] Cureington-5 at 44:15-46:10.
[193] Cureington-5 at 45:12-46:15.

would create more reactive power, more flexibility to take outages and less dependence on the transmission system.[194] ENO witness Rice also states the CT Alternative is expected to produce significant economic benefits (hundreds of millions of dollars) in terms of new business sales, household earnings, and jobs in both the State and regional economies and provides a study of the economic impact of NOPS in support of this assertion.[195]

The intervenors disagree with ENO's economic analysis, as do the Advisors. Air Products argues that ENO's load forecast does not justify adding 226 MW of capacity.[196] The Joint Intervenors argue that NOPS will leave ENO with significantly more capacity than it needs to fulfill its load obligations.[197] Advisor witness Rogers finds that the significant reduction in projected total load requirements since the 2015 Final IRP, where a 250 MW CT was selected as part of the preferred portfolio, would strongly suggest that 226 MW may be greater than the optimal size for the proposed peaking plant, on a capacity need basis.[198]

The primary risk in building a plant that offers excess capacity is that it leaves customers exposed to capacity price risks, and the greater the excess amount of capacity, the greater the exposure. ENO's analysis of the economic viability of the CT Alternative depends heavily on sales of excess capacity into the MISO capacity market at very high prices to generate revenues to offset the cost impact to ENO customers. ENO assumes that supply and demand will each equilibrium in MISO in the near future and that when it does, capacity prices will approach the cost of new entry ("CONE"), which is the price at which it would be economic for a new plant to

[194] Rice-3 at 7:21-8:17.
[195] Rice-3 at 15:20-16:4; Rice-1, Exhibit CLR-1 at ii.
[196] Brubaker-1 at 3:6, 5:15-6:9; Brubaker-2 at 3:11-12 and 6:10-12.
[197] Luckow-1 at 4:18-19.
[198] Rogers-1 at 9:3-6.

be built.[199] However, both the Joint Intervenors and the Advisors question the basis of ENO's assumptions that MISO capacity market prices will rise high enough and quickly enough to ensure that ENO's anticipated revenues are achieved.

Joint Intervenor witness Luckow, whose testimony was adopted by witness Fagan, states that ENO assumes it will be able to sell excess power at a hefty price in the future, but fails to take into account that capacity prices are likely to grow more slowly than it projects, making the CT Alternative uneconomic.[200] Luckow argues that ENO relies heavily on sales of excess capacity in the MISO market to justify its CT proposal, however, that poses significant risks and uncertainties.[201] He states that if you assume a more reasonable capacity cost ($150/MW-day) the CT Alternative becomes more expensive than the Transmission Alternative.[202] Luckow argues that the NOPS analysis overstates MISO capacity market prices, which makes the NOPS CT excess capacity appear more attractive than it should be and reliance upon the MISO capacity market to meet New Orleans' needs less attractive.[203] ENO's assumption that the MISO capacity market will drive towards equilibrium in 2022 is unreasonable, and gross CONE is not a reasonable proxy for long-term capacity prices.[204]

Joint Intervenor witness Stanton argues that ENO finds that NOPS is the economic choice for New Orleans only when assuming very high projections of future capacity market prices.[205] Joint Intervenor witness Fagan challenges ENO's assertion that the MISO capacity market will reach equilibrium of supply and demand in the near future and that this will cause

---

199 Rogers-1 at 32:9-15.
200 Luckow-1 at 4:19-5:2.
201 Luckow-1 at 12:4-17.
202 Luckow-1 at 19:3-20:20.
203 Luckow-1 at 14:4-19:2.
204 Luckow-1 at 14:4-19:2.
205 Stanton-1 at 7:5-8; 35:9-41:2.

prices to increase dramatically.[206] Fagan posits that continuing improvements to the transmission system, installation of new wind and solar resources, availability and costs for new storage systems, the pace of retirement of coal and other older fossil resources, and additions of new conventional resources (gas-fired technologies) will affect the overall level of resource adequacy in the MISO region.[207] Joint Intervenor witness Fagan argues that ENO's economic analysis of both gas plants and alternatives is flawed and relies on misleading assumptions.[208]

Joint Intervenors witness Stanton argues that procuring too much capacity carries a risk to ENO and its ratepayers.[209] She states that costs of a combustion turbine are high compared to other technologies[210] and combustion turbines sit idle for most of the year.[211] Luckow also argues that when ENO filed its additional testimony regarding the CT with its Supplemental Analysis, it relied upon AURORA for production cost modeling, rather than capacity expansion modeling, which is what it should have used.[212] He argues that ENO did no optimization for the lowest cost resource, but its production cost modeling is the only analysis that evaluates the cost of the CT against any other option.[213] He states that the only value of the CT is as a capacity unit.[214]

Advisors witness Rogers concludes that ENO has not economically justified the CT Alternative because (i) ENO's economic modeling of the CT Alternative relies heavily on forecasted MISO capacity market revenues that he finds to be questionable and (ii) when

---

[206] Fagan-1 at 27:7-13.
[207] Fagan-1 at 27:7-13.
[208] Fagan-1 at 3:22-4:3.
[209] Stanton-1 at 41:3-43:13.
[210] Stanton-1 at 41:3-43:13.
[211] Stanton-1 at 41:3-43:13.
[212] Luckow-1 at 7:4-8:23.
[213] Luckow-1 at 7:4-8:23.
[214] Luckow-1 at 10:1-9.

employing his illustrative MISO capacity market prices, the CT Alternative and the RICE Alternative have roughly the same economic attractiveness.[215] Rogers acknowledges that ENO's analysis shows a roughly 3% difference in net present value between the CT Alternative and the Transmission Alternative, suggesting that, on an economic basis, the Council may be economically indifferent to the two scenarios when considering the accuracy by which the next 20 years can be estimated.[216] However, he believes the Council may be less indifferent if capacity market price is considered.[217] He explains that the magnitude of dollars associated with the capacity market prices is evident in the swing in MISO capacity purchases and sales between scenarios.[218] The CT Alternative scenario includes $113 million net present value in MISO capacity market revenues, in the Transmission Alternative, there is $72 million net present value in MISO capacity market purchases.[219] This $185 million net present value difference in variable costs and $54 million net present value difference in total costs between the two cases, suggests that the results of the analyses are significantly impacted by the level of MISO capacity market price forecast.[220] This means that if ENO's MISO capacity market price forecast is wrong, the outcome for New Orleans customers could be substantially different than what ENO sets forth. The Advisors question the efficacy of ENO's MISO capacity market price forecasts and have concerns that if ENO's projected capacity market prices do not materialize, ENO ratepayers could be exposed to significantly increased economic risks.

As Advisors witness Rogers explains, historic MISO capacity prices have been significantly lower than the CONE that ENO uses to make its forecast of future MISO capacity

---

[215] Vumbaco-1 at 24:19-25:3.
[216] Rogers-1 at 30:18-31:9.
[217] Rogers-1 at 30:18-31:9.
[218] Rogers-1 at 30:18-31:9.
[219] Rogers-1 at 30:18-31:9.
[220] Rogers-1 at 30:18-31:9.

prices.[221] Rogers notes that ENO assumes as capacity supply in MISO approaches equilibrium with demand (which ENO projects in 2022) prices will go up to approximately the level of CONE.[222] However, Rogers notes that while ENO's approach is generally based on the theory of supply and demand, that theory may not be applicable to capacity prices in MISO South.[223] Rogers notes that in several instances it has been noted before FERC that prices in MISO's capacity auction have been consistently too low to attract new generation investments and that the market is not really the prime driver of entry or expansion decisions. Rather the states located in MISO depend on state resource planning efforts by regulated utilities to assure that their load serving entities ("LSEs") have sufficient capacity to meet load.[224] Thus, it is more reasonable to expect MISO capacity market prices to generally be below CONE except for in certain, specific circumstances.[225] Building capacity in excess of ENO's needs in relation to the capacity market exposes ratepayers to unnecessary risk associated with the known fixed costs of the CT Alternative as compared to unknown market prices for the excess capacity necessary to make those resource additions economic.[226] Rogers believes several adjustments need to be made to ENO's economic analyses.[227] Once he adjusted for ENO's inconsistent transmission upgrade investment information, used non-levelized results, and used a much lower MISO capacity price forecast, his analysis produced a different economic ranking than did ENO's.[228] Rogers' analysis shows that if capacity prices do not escalate at the rapid pace that ENO predicts,

---

[221] Rogers-1 at 32:16-33:4.
[222] Rogers-1 at 35:10-17.
[223] Rogers-1 at 36:9-10.
[224] Rogers-1 at 36:10-38:6.
[225] Rogers-1 at 38:7-15.
[226] Rogers-1 at 34:13-35:7.
[227] Rogers-1 at 39:1-42:4.
[228] Rogers-1 at 39:1-42:4.

then the Transmission Alternative becomes the least cost under a significant range of capacity market price forecasts.[229]

The changing assumptions around the MISO capacity prices and other inputs have a significant impact on ratepayer bills. For example, ENO estimates the impact of the CT Alternative on the average residential monthly bill to be $5.61.[230] However, as Advisor witness Watson testifies, once the calculations are adjusted as recommended by Rogers, the rate impact of the CT Alternative increases to $7.33.[231] By way of comparison, the expected impact of the Transmission Alternative decreases from $6.49 under ENO's analysis to $1.82, and the RICE Alternative decreases from $7.19 to $6.91.

The Joint Intervenors also oppose the CT Alternative on environmental grounds. However, ENO has entered substantial evidence into the record that the CT Alternative will have a significantly reduced impact compared to the prior units at the Michoud site, that it will comply with all applicable environmental laws and regulations and that ENO has taken steps to mitigate any potential risk of flooding.

As is discussed in greater detail below, ENO has submitted a technical report into the record dated November 16, 2016 prepared by C-K Associates, LLC and Losonsky & Associates, Inc. ("C-K Report") which addresses the evaluation of groundwater withdrawal and air quality associated with the proposed CT Alternative.[232] The C-K Report was developed to address

229 Rogers-1 at 43:1-45:11.

230 Watson-1 at 13:3-4.

231 Watson-1 at 15, Table 5.

232 Technical Report - Evaluation of Groundwater Withdrawal and Air Quality, C-K Associates, LLC and Losonsky & Associates, Inc. ("C-K Report" or "Report") attached to the Supplemental Direct Testimony of Jonathan E. Long, Exhibit JEL-6 (Nov. 18, 2016).

concerns raised and to understand how the proposed NOPS might impact subsidence and air quality in New Orleans East.[233]

The C-K Report also concludes that the CT Alternative's proposed groundwater withdrawal rate of 96 gallons per minute ("gpm") is "relatively low" and will not contribute to subsidence in New Orleans East.[234] By way of comparison, in 1983 there were approximately 200 wells in the Gonzales-New Orleans aquifer along the Mississippi River from St. Charles to St. Bernard Parishes, roughly half of which had flow rates in the range of 1,000 to 2,000 gpm.[235] The drawdown calculations for the CT Alternative predict a maximum drawdown over a 10-year period of about one foot near the NOPS pumping well, diminishing to half of a foot or less at a distance of several thousand feet away, and one quarter foot or less at a distance of two miles from the well.[236] These calculations were performed using the most conservative assumption that the CT Alternative will operate 24 hours a day, 365 days a year.[237]

An additional report,[238] developed and prepared by CB&I Governmental Solutions, Inc. ("CB&I Report") and submitted into evidence in this proceeding by ENO, also reached the same conclusions as those reached in the C-K Report.[239] Specifically, the CB&I Report concludes that, based on drawdown and settlement calculations and taking known aquifer characteristics into account, the proposed groundwater withdrawals for the CT Alternative and the RICE Alternative will be too small to contribute to any subsidence in the Michoud area.[240] In addition, Dr.

---

[233] J. Long-3, Exhibit JEL-6 at 1.

[234] J. Long-3, Exhibit JEL-6 at 1.

[235] J. Long-3, Exhibit JEL-6 at11.

[236] Losonsky-1 at 13:16-19.

[237] Losonsky-1 at 13:14-21.

[238] Evaluation of Proposed Groundwater Withdrawals and Subsidence Entergy New Orleans Power Station, CB&I Governmental Solutions, Inc. dated June 16, 2017 ("CB&I Report") marked as Exhibit GL-3 and attached to Losonsky-1.

[239] Losonsky-1 at 17:19-22.

[240] Losonsky-1 at 17:19-22.

Losonsky testified that the analytical methods employed in the addendum to the C-K Report and the CB&I Report are founded on the same hydrogeologic and geotechnical principles.[241] Dr. Losonsky's analysis in this case also supports the findings and conclusions contained in the CB&I Report.[242]

The Advisors agree with ENO that the groundwater withdrawal associated with the proposed CT Alternative will not exacerbate subsidence or cause damage to infrastructure in New Orleans East. ENO presented expert testimony that is well supported by two detailed studies containing site specific analysis and calculations that also provided historical comparisons to past groundwater usage. The significantly decreased expected pumping rates for the CT Alternative reduce the potential for any additional subsidence that may be attributable to groundwater withdrawal. The drawdown calculations for the CT Alternative predict a considerably reduced maximum drawdown with the new and efficient technology of the proposed CT Alternative. As also discussed above, it is noteworthy that these calculations were performed using the most conservative assumption that the CT Alternative will operate 24 hours a day, 365 days a year.

The C-K Report, upon which ENO and its experts rely heavily to prove that the groundwater withdrawal resulting from operating the CT Alternative will not exacerbate subsidence, also discusses an evaluation of the potential air emissions associated with the operation of NOPS. The C-K Report concluded that the "emissions from the proposed [CT Alternative] will result from combustion of clean burning natural gas; in no case, will the emissions cause air quality to exceed regulatory standards, which are protective of human health

[241] Losonsky-1 at 18:1-6.
[242] Losonsky-1 at 18:15-17.

and the environment."[243] According to ENO witness Bliss M. Higgins, the CT Alternative would result in a substantial decrease in permitted emissions for NOPS as compared to the currently permitted Michoud Power Plant.[244] The EPA sets federal air quality standards, formally known as National Ambient Air Quality Standards ("NAAQS"), to protect public health and the environment.[245] These standards are expressed as an allowable concentration of pollution in the air. The C-K Report compared the results of air dispersion modeling for the CT Alternative to the NAAQS and concluded that the CT Alternative is at least 96% below the NAAQS for all modeled chemicals and that personal ground-level exposure due to the proposed emissions will be well below the applicable air standards.[246] According to ENO, these conclusions reached in the C-K Report demonstrate that the CT Alternative would not result in significant adverse air quality effects.[247]

Joint Intervenor witness Stanton argues that new natural gas electric generators will emit greenhouse gases.[248] She further argues that the Council and the Mayor have goals to reduce emissions, and ENO has not provided the necessary information to assess the impact of NOPS on New Orleans' emissions.[249] The Joint Intervenors argue that there is no safe level of exposure to certain pollutants. Specifically, George Thurston testified that there is no evidence to date that there is any threshold below which the adverse effects of air pollution will not occur.[250] Mr. Thurston also more specifically opines that "any increase in pollution will increase the risk of adverse effects at all levels of prevailing air pollution, even when the NAAQS standards are not

[243] J. Long-3, JEL-6 at 1.
[244] Higgins-1 at 17:32-33.
[245] Higgins-1 at 32:5-6.
[246] Higgins-2 at 14:3-6.
[247] Higgins-2 at 14:6-8.
[248] Stanton-1 at 7:15-18.
[249] Stanton-1 at 7:15-18.
[250] Thurston-1 at 15:5-6.

violated."[251] Mr. Thurston also disputes ENO's witness, Higgins, on the effectiveness of NAAQS and argues that meeting NAAQS air quality standards does not prevent significant adverse health effects from occurring in the exposed population.[252] Thus, it is clear that meeting current EPA and LDEQ requirements will not be sufficient to satisfy the Joint Intervenors. However, nowhere do they suggest a standard the Council could apply, or explain why such a standard should be applied only to ENO and not to all sources of pollution in the City.

In her rebuttal, Ms. Higgins makes clear that EPA establishes the NAAQS to prevent ambient concentrations of a pollutant that may pose an unacceptable risk of harm and that the NAAQS do not represent a defined "no-effect threshold."[253] She also clarified that EPA sets NAAQS that are protective of public health with an adequate margin of safety.[254]

The Advisors agree with ENO's witness, Higgins, that the CT Alternative would result in a substantial decrease in permitted emissions for NOPS as compared to the permitted emissions of the prior Michoud units. While it is extremely important for ENO to have generating capacity in New Orleans for reliability purposes, this generation should be clean, efficient and have no significant impact on the environment. As noted above, the C-K Report's conclusions that the CT Alternative would be at least 96% below the NAAQS for all modeled chemicals and that personal ground-level exposure due to the proposed emissions will be well below the applicable air standards are significant and persuasive to support a finding that the CT Alternative will be compliant with environmental standards in this regard.[255]

The Joint Intervenors argue that that is no safe level of exposure to certain pollutants. George Thurston testified for the Joint Intervenors that there is no evidence to date that there is

[251] Thurston-1 at 17:13-15.
[252] Thurston-1 at 18:6-7.
[253] Higgins-2 at 3:19-4:1-3.
[254] Higgins-2 at 3:-14-16.
[255] Higgins-2 at 50:11-15.

any threshold below which the adverse effects of air pollution will not occur.[256] The Advisors disagree with this assertion. Simply because a source creates emissions greater than zero does not necessarily infer adverse health effects. If this logic were accepted, the vast majority of vehicles and manufacturing facilities across the country would be prohibited from operation because they violate the "more than zero" standard that the Joint Intervenors have advanced in this case. While the Advisors support clean sources of energy, especially renewables, when cost effective and appropriate, responsible energy policymaking requires consideration of a number of factors that inform decisions to acquire new resources.

While the Advisors do not recommend that the Council approve the CT Alternative, it should be acknowledged that the CT Alternative would fully mitigate ENO's NERC reliability issues without the need for additional transmission upgrades.[257] It would reduce dependence on transmission to import power, which might make it easier to schedule planned outages for maintenance of transmission facilities or generators in the area.[258] It also would reduce the need to construct additional river crossing transmission for at least 10 years[259] and provide reactive power support, which would increase the reliability of the surrounding transmission system and enhances its ability to appropriately respond to system disturbances.[260]

However, the CT does not have black start capability.[261] It has a small emergency diesel generator to supply vital auxiliary loads in the event of a complete power loss, but the diesel generator is too small to have black-start capability.[262] ENO witness Charles Long explains that

[256] Thurston-1 at 15:5-6.
[257] Movish-1 at 20:16-17; C. Long-2 at 2:8-13, 13:7-8; Vumbaco-1 at 21:8-11; Hr'g Tr. 12/15/17, 124:22-24.
[258] C. Long-2 at 26:4-7.
[259] C. Long-2 at 27:5-18, 28:10-29:2.
[260] C. Long-2 at 26:16-18.
[261] Hr'g Tr. 12/15/17, 230:17-231:3.
[262] Movish-1 at 6:14-15.

ENO's current black start plan involves a cranking route that begins with restoration of power from the Waterford Unit 4 black-start resource.[263] Once the Waterford resources are energized, he explains, those resources would then be used to continue restoration of power along the Waterford-Ninemile transmission corridor and on to Michoud to bring power into New Orleans.[264] It is important to note however, that this plan is dependent on lines outside of ENO's control.[265] Charles Long explains that if the transmission grid anywhere along that 40-mile path were damaged, ENO's ability to provide electric service to ENO customers would be impaired.[266] Further, ENO has not performed studies demonstrating the feasibility of black starting the CT Alternative unit with other generating resources in DSG.[267]

A local resource with black start capability, in close electrical proximity to the electric demand, would enable much more effective voltage and frequency response during the black start process and therefore would greatly enhance ENO's ability to restore electric service, should a complete loss of service on the electric system occur.[268] A facility with on-site black start capability might also be able assist in restarting the motors at the Sewage & Water Board ("S&WB") pumping station in the event of a loss of electrical service.[269] In the Advisors' view, having black start capability would be critical to insuring that local generation could be depended upon to power S&WB's pumping plant, in the event of a failure of S&WB's generators during critical flooding events.[270]

---

[263] C. Long-2 at 28:10-18; C. Long-3 at 31:14-19.
[264] C. Long-2 at 28:10–29:2; C. Long-3 at 31:15-17.
[265] C. Long-3 at 31:17-18, 20-21.
[266] Movish-1 at 38:21-22.
[267] Movish-1 at 38:1-3, 39:1-3.
[268] C. Long-2 at 29:7-11. C. Long-3 at 31:21- 32:1.
[269] C. Long-3 at 44:17-45:18.
[270] Movish-1 at 9:13-16.

ENO and the Advisors agree that black start capability is "more beneficial in the event of wide-spread transmission system outages during a major storm."[271] Having local generation in the City that provides a dependable source of black starting power and avoids the risks of transmission failure is especially important given that ENO's system exists in an extreme weather event region.[272] The CT Alternative does not have this very important feature, and therefore, from a reliability standpoint, the Advisors believe that other alternatives, such as the RICE Alternative would be preferable to the construction of the CT Alternative.

The Advisors further conclude that while the CT Alternative would fully mitigate the transmission reliability need identified by ENO and confirmed by the Advisors' own analysis, it is not in the public interest because it would result in a significant excess of capacity and subject ENO's customers to an unacceptable risk of exposure to unpredictable MISO capacity market prices -- in other words, the risk that ENO would not be able to make sufficient revenues in the MISO capacity market to offset a sufficient amount of costs to make the CT Alternative economic for ratepayers is too high.

B. <u>WHETHER ENO'S SELECTION OF A RICE UNIT IS IN THE PUBLIC INTEREST</u>: The construction of the RICE Alternative in combination with the incorporation of renewable technologies and realistically achievable cost effective DSM potential in ENO's service territory is in the public interest.

The Advisors conclude 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. This conclusion is based upon: (i) the information provided in ENO's applications;

---

[271] C. Long-2 at 28:2-5. *See also* Movish-1 at 38:11-15.
[272] Movish-1 at 40:1-5.

(ii) the discovery and transmission models provided to the Advisors, inclusive of ENO's assumptions contained therein; (iii) the Advisors' evaluation of same, as contained in the Direct Testimony of the Advisor witnesses filed in this docket; (iv) the RICE Alternative's ability to mitigate risk and provide operational flexibility; and (v) ENO's representations that it will comply with all applicable laws and regulations, including environmental laws and regulations.

Although ENO prefers the CT Alternative, it does acknowledge that while the portfolios that include the RICE unit are -- in ENO's analysis -- ranked below the portfolios including the CT unit, the RICE unit is a reasonable alternative to the CT.[273] ENO argues that the RICE technology is a well-known technology and is the best option for a smaller capacity addition.[274] ENO explains that the RICE technology had the lowest levelized cost of electricity on a $/MWh basis compared to other alternatives considered, as well as other benefits such as low water usage, a low emissions profile, the ability to support renewable resources, the inclusion of black start capability, the addition of generation to DSG, the opportunity to provide a hedge against market and supply related risks in MISO, increased flexibility to take outages to maintain the system, add reactive power, lessen dependence on transmission, and provide storm restoration support.[275] ENO states that another benefit of the RICE Alternative is that it would address the possibility of cascading, uncontrolled outages under certain contingencies, and would leave only one very minor overloading issue on the transmission system by 2027.[276]

[273] Cureington-5 at 5:6-10, 28:4-29:8.
[274] Rice-3 at 9:16-18; J. Long-4 at 7:5-16.
[275] Rice-3 at 10:5-10:9; 12:10-14:3; J. Long-4 at 6:18-7:2.
[276] Rice-3 at 14:4-8; C. Long-2 at 11:9-14.

Under ENO's analysis, the RICE unit came in second or third most cost effective in each of the various sensitivities ENO ran on the four Requested Portfolios.[277] ENO finds that although the RICE Alternative has a higher Total Relevant Supply Cost when compared to the CT Alternative, the increase is comparable to the Transmission Alternative, and it is comparable to the increase of the Transmission Alternative in the low gas scenario.[278] Deploying a dispatchable unit in New Orleans mitigates market supply related risks, especially as the market reaches equilibrium.[279] It also provides additional local reliability benefits which do not come under the Transmission Alternative.[280] The gas scenarios are clearly preferable over the transmission scenario.[281] The RICE Alternative has further advantages -- lower water usage, a low emissions profile, and enhanced ability to support renewable resources (quick startup, ability to start and stop multiple times per day) and black start capability.[282] This option is only 2.3% more expensive on average than the Transmission Alternative.[283]

Like the CT Alternative discussed above, Dr. Losonsky, citing the addendum to the C-K Report,[284] testified that the groundwater withdrawal associated with the RICE Alternative will not exacerbate ground subsidence or cause damage to infrastructure in New Orleans East.[285]

With regard to the RICE Alternative, the drawdown calculations predict a maximum drawdown over a 10-year period of half an inch or less near the NOPS pumping well,

---

[277] Cureington-5 at 34:1-35:3.
[278] Cureington-5 at 44:8-47:10.
[279] Cureington-5 at 44:8-47:10.
[280] Cureington-5 at 44:8-47:10.
[281] Cureington-5 at 44:8-47:10.
[282] Cureington-5 at 44:8-47:10.
[283] Cureington-5 at 44:8-47:10.
[284] Addendum to the C-K Associates Technical Report of November 16, 2016: Evaluation of Predicted Drawdown and Consolidation Settlement Resulting from Proposed NOPS Pumping ("Addendum to C-K Report"), attached to the Supplemental and Amending Testimony of Dr. George Losonsky as GL-2.
[285] Losonsky-1 at 6:21-23.

diminishing to approximately one hundredth of an inch several thousand feet away from the well.[286] These calculations were performed using the most conservative assumption that NOPS will operate 24 hours a day, 365 days a year.[287] Based on engineering estimates provided by ENO's equipment vendor and contractor, the RICE Alternative will require a reduced pumping rate of 3.9 gpm.[288] The anticipated pumping rate for the RICE Alternative is less than one tenth of the pumping rate for the CT Alternative.[289] According to the Addendum to the C-K Report, when compared to the original CT Alternative proposed flow rate of 96 gpm, the RICE Alternative usage rate will result in a 95% groundwater use reduction.[290] When compared to the deactivated Michoud units, the RICE Alternative usage rate will result in a 99.9% groundwater use reduction.[291]

The Advisors agree with ENO that the groundwater withdrawal associated with the proposed RICE Alternative will not exacerbate subsidence or cause damage to infrastructure in New Orleans East. ENO presented expert testimony that is well supported by two detailed studies containing site specific analysis and calculations that also provided historical comparisons to past groundwater usage. The Advisors are persuaded by the evidence presented by ENO that the risk of subsidence resulting from groundwater withdrawal is *de minimis* considering the expected pumping rate for the RICE Alternative is less than one tenth of the pumping rate for the CT Alternative. The Advisors also find it compelling that ENO's evidence demonstrates that when compared to the deactivated Michoud units, the RICE Alternative usage rate will result in a 99% groundwater use reduction. Like the CT Alternative analysis, it is

[286] Losonsky-1 at 14:12-14.
[287] Losonsky-1 at 11:16-17.
[288] Losonsky-1, Exhibit GL-2 at 2.
[289] Losonsky-1, Exhibit GL-2 at 2.
[290] Losonsky-1, Exhibit GL-2 at 2.
[291] Losonsky-1, Exhibit GL-2 at 2.

noteworthy that the drawdown calculations were performed using the most conservative assumption that the RICE Alternative will operate 24 hours a day, 365 days a year. The Advisors conclude that the RICE Alternative is in the public interest and should be approved for several reasons, including the significant anticipated reduction in groundwater use and air emissions associated with the new units.

Ms. Higgins, in addition to her analysis regarding the level of air emissions anticipated from the CT Alternative, also provided similar analyses regarding the RICE Alternative. She testified that the RICE Alternative would result in a substantial decrease in permitted emissions for the NOPS as compared to the currently permitted Michoud Power Plant.[292] C-K Associates performed a modeling exercise for the RICE Alternative that was similar to that performed to evaluate the CT Alternative.[293] Specifically, a screening model exercise using the full anticipated permitted emission rates for the RICE Alternative was performed without taking into consideration the emissions reductions associated with the deactivated Michoud units.[294] The modelling demonstrated that the ambient concentrations for every pollutant modeled were well below the NAAQS, thus the RICE Alternative would not result in significant adverse air quality effects.[295]

The Joint Intervenors present the same air emissions argument for the CT Alternative and the RICE Alternative; that there is no safe level of exposure to certain pollutants. Specifically, George Thurston testified that there is no evidence to date that there is any threshold below which the adverse effects of air pollution will not occur.[296] Mr. Thurston also more specifically opines that “any increase in pollution will increase the risk of adverse effects at all levels of

[292] Higgins-1 at 17:32-33.
[293] Higgins-2 at 14:9-11.
[294] Higgins-1 at 50:9-15.
[295] Higgins-1 at 50:14-15.
[296] Thurston-1 at 15:5-6.

prevailing air pollution, even when the NAAQS standards are not violated.[297] Mr. Thurston also disputes ENO's witness, Higgins, on the effectiveness of NAAQS and argues that meeting NAAQS air quality standards does not prevent significant adverse health effects from occurring in the exposed population.[298]

In her rebuttal, Ms. Higgins makes clear that EPA establishes the NAAQS to prevent ambient concentrations of a pollutant that may pose an unacceptable risk of harm and that the NAAQS do not represent a defined "no-effect threshold."[299] She also clarified that EPA sets NAAQS that are protective of public health with an adequate margin of safety.[300]

The Advisors agree with ENO's witness, Higgins, that the RICE Alternative would result in a substantial decrease in permitted emissions for NOPS as compared to the currently permitted Michoud Power Plant. While it is extremely important for ENO to have generating capacity in New Orleans for reliability purposes, this generation must be clean, efficient and have no significant impact on the environment. The Advisors conclude that the RICE Alternative is the best option to meet ENO's reliability issues and avoid any adverse impact on public health or the environment. C-K Associates concluded, and the Advisors agree, that the evidence presented by ENO shows that the predicted ambient concentrations from the RICE Alternative are well below the NAAQS for all modeled chemicals.

The Joint Intervenors argue that that is no safe level of exposure to certain pollutants. George Thurston testified for the Joint Intervenors that there is no evidence to date that there is any threshold below which the adverse effects of air pollution will not occur.[301] The Advisors disagree with this assertion. Simply because a source creates emissions greater than zero does

[297] Thurston-1 at 17:13-15.
[298] Thurston-1 at 18:6-7.
[299] Higgins-2 at 3:19-4:1-3.
[300] Higgins-2 at 3:14-16.
[301] Thurston-1 at 15:5-6.

not necessarily infer adverse health effects. If this logic were accepted, the vast majority of vehicles and manufacturing facilities across the country would be prohibited from operation because they violate the "more than zero" standard that the Joint Intervenors have advanced in this case. While the Advisors support clean sources of energy, especially renewables when cost effective and appropriate, responsible energy policymaking requires consideration of a number of factors that inform decisions to acquire new resources.

While the Council does not issue environmental permits, if the Council chooses to approve one of ENO's proposed generating options, it should require the Company to present evidence of all applicable federal, state, and local permits and approvals in connection with its application. To that end, ENO witness Charles Rice committed in the hearing in this matter to operate the plant in an environmentally safe manner and to comply with all EPA, LDEQ and local laws and regulations.[302]

ENO's largest industrial customer, Air Products, agrees with the Advisors that the RICE Alternative is the more appropriate alternative.[303] Not only does the size of the resource correspond more closely to the forecasted need for capacity, Air Products argues, but the RICE units are advantageous in a number of other respects.[304] Air Products witness Brubaker, who has more than 50 years of experience in the industry[305] testifies that RICE units: (1) have a lower heat rate (use fewer BTUs per kWh than CT);[306] (2) are less costly to start, because fuel consumption per start is generally less expensive than for CTs;[307] (3) more flexible than the CT

[302] Hr'g Tr. 12/20/17, 132:21-25, 133:1-12.
[303] Brubaker-2 at 3:13-16 and 8:9-13, refers to HSPM SEC-12 at 4.
[304] Brubaker-2 at 3:13-16 and 8:9-13, refers to HSPM SEC-12 at 4.
[305] Brubaker-1, Appendix A.
[306] Brubaker-2 at 8:16-18.
[307] Brubaker-2 at 8:18-19.

in terms of the minimum required run times when the resource is started;[308] and (4) can be run for a shorter period of time than the CT which results in cost savings.[309] He also explains that the modular nature of the proposed RICE Alternative is an advantage.[310] Because there are seven separate units, he explains, all of the capacity does not need to be committed whenever there is a capacity need, the amount committed and operated can be matched more closely to actual system needs.[311] Also, if one unit goes down, others can continue to run.[312] He also states that the forced outage rate of the RICE units is lower than for the CT, which makes them an inherently more reliable choice.[313] He agrees that the smaller revenue requirement for a smaller unit would create less impact on ratepayers because it creates less exposure to capital costs.[314] He does argue, however, that even the smaller unit would provide substantially more capacity than ENO's load forecast would justify for about 10 years.[315] Brubaker also notes that ENO represents that the RICE Alternative will use less water than is required by the CT, which is beneficial from both cost and use of resource standpoints.[316]

Brubaker does propose that ENO construct infrastructure to accommodate all seven RICE units, but construct only 4-5 of the proposed units now and defer action on the remainder until a later time.[317] He argues this would reduce capital outlay and cost impact and would provide time to learn how energy efficiency measures and general demographic and economic conditions

[308] Brubaker-2 at 8:21-9:3.
[309] Brubaker-2 at 8:21-9:3.
[310] Brubaker-2 at 9:4-9.
[311] Brubaker-2 at 9:4-9.
[312] Brubaker-2 at 9:4-9.
[313] Brubaker-2 at 9:10-11.
[314] Brubaker-2 at 9:15-16.
[315] Brubaker-2 at 3:17-18.
[316] Brubaker-2 at 9:12-13.
[317] Brubaker-2 at 4:19-5:2 and 10:6-10.

actually impact the load.[318] However, the Advisors do not believe that installing only 4-5 of the units at this time would effectively meet the reliability need of ENO and would only add costs over the long term.[319]

Both ENO and the Advisors conclude that the RICE Alternative would mitigate ENO's most serious reliability concerns.[320] In particular, the RICE Alternative addresses the potential cascading outages in ENO's service territory.[321] ENO notes that some transmission investment may be needed to fully mitigate the NERC reliability issues.[322] However, ENO's analyses show that it will be about 10 years before such transmission upgrades may be needed.[323] The Advisors reach a similar conclusion.[324] The RICE unit is capable of fully mitigating the NERC reliability issues over the planning period if coupled with transmission upgrades.[325] In addition, in 2019 (*i.e.*, before construction on the unit is completed), some load shedding (up to 50 MW) might also be required in the event of a NERC P6 contingency.[326] Advisor witness Movish states that ENO has not provided information on the number or location of customers who would be affected by load shedding in that year, but notes that Air Products has an agreement with ENO which allows ENO to interrupt up to 20 MW of its load at ENO's discretion during ENO's four-month peak load period, which could alleviate some of the need.[327]

The RICE Alternative is expected to take roughly one year less to construct than the CT Alternative, and at least two years less than the Transmission Alternative based on ENO's

---

[318] Brubaker-2 at 10:9-12.
[319] Hr'g Tr. 12/18/17, 335:7-336:2.
[320] C. Long-2 at 2:14-16. Vumbaco-1 at 21:8-11.
[321] C. Long-2 at 2:15-16.
[322] C. Long-2 at 2:16-18.
[323] C. Long-2 at 11:6-13; Hr'g Tr. 12/15/17, 162:16-21, 165:2-4.
[324] Movish-1 at 20:1-2.
[325] Movish-1 at 20:2-4.
[326] Movish-1 at 20:4-5.
[327] Movish-1 at 20:7-11.

economic modeling. As such, ENO's NERC reliability issues would be addressed sooner by the RICE Alternative than by the CT Alternative, and far more quickly than a no-NOPS (transmission-only) scenario particularly given the constructability challenges that the Company must overcome in order to implement any transmission upgrades.[328]

Further, if it turns out in 2027 that ENO does need to make transmission upgrades, the locally-sited RICE Alternative would "unload" the transmission lines so that ENO would likely be able to get the transmission outage necessary to complete the upgrades.[329]

The RICE Alternative also would provide other significant benefits to New Orleans, including operational flexibility, dynamic system support for voltage regulation, on-site black start capacity to support restoration of service after a major outage or storm event, and the ability to provide a source of power to ENO's critical loads in the event of an outage.[330]

The RICE Alternative would reduce dependence on transmission to import power, which might make it easier to schedule planned outages for maintenance of transmission facilities or generators in the area. It also would reduce the need to construct additional river crossing transmission for at least 10 years. It also would provide reactive power support, which would increase the reliability of the surrounding transmission system and enhances its ability to appropriately respond to system disturbances.[331]

---

[328] Vumbaco-1 at 27:17-28:20. Hr'g Tr. 12/15/17, 171:13-19, 208:9-25.
[329] Hr'g Tr. 12/15/17, 233:20-234:3.
[330] Movish-1 at 4:21-5:5.
[331] C. Long-2 at 26:4-28:2.

Importantly, the RICE Alternative has on-site black start capability.[332] ENO explains that its current black start plan begins with restoration of power from the Waterford Unit 4 black start resource. Once the Waterford resources are energized, those resources would then be used to continue restoration of power along the Waterford-Ninemile transmission corridor to bring power into New Orleans.[333] The plan is dependent on lines outside of ENO's control.[334] Absent the black start capability of the RICE unit, if the transmission grid anywhere along that 40-mile path were damaged, ENO's ability to restore electric service to ENO customers would be impaired.[335]

The ability to black start the RICE Alternative in the event that New Orleans becomes disconnected from the regional transmission grid is an advantage that is invaluable and cannot be overlooked.[336] Of the proposals before the Council, only the RICE Alternative has this critically important feature. Having local generation in the City that provides a dependable source of black starting power and mitigates the risk associated with transmission failure is especially important given that ENO's system exists in an extreme weather event region.[337] A local resource with black start capability, in close electrical proximity to the electric demand, would enable much more effective control of voltage and frequency and therefore would greatly enhance ENO's ability to restore electric service, should a complete loss of service on the electric system occur.[338] A facility with on-site black start capability might also be able assist in restarting the motors at the S&WB pumping station in the event of a loss of electrical service.[339]

---

[332] Hr'g Tr. 12/15/17, 230:17-231:3.
[333] C. Long-2 at 28:10-29:2; C. Long-3 at 31:15-17.
[334] C. Long-3 at 31:17-18, 20-21.
[335] Movish-1 at 38:13-15.
[336] Rogers-1 at 51:5-19. *See also* C. Long-2 at 28:2-5; Movish-1 at 38:11-15.
[337] Movish-1 at 40:1-5.
[338] C. Long-2 at 29:7-11. C. Long-2 at 31:21-32:1.
[339] C. Long-3 at 44:17-45:18.

In the Advisors' view, having black start capability would be critical to insuring that local generation could be depended upon to power S&WB's pumping plant, in the event of a failure of S&WB's generators during critical flooding events.[340]

Based upon the record in this proceeding, including the information provided in ENO's application, discovery responses, and transmission models and underlying assumptions, as well as the Advisors' evaluation of this information, and in light of the RICE Alternative's ability to mitigate risk and provide operational flexibility; the Advisors conclude 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. Accordingly, the Advisors recommend that the Council find the proposed construction of the RICE Alternative to be in the public interest.

As is discussed above with respect to the CT Alternative, Advisor witness Rogers' analysis shows that if capacity prices do not escalate at the rapid pace that ENO predicts, then the Transmission Alternative becomes the least cost under a significant range of capacity market price forecasts.[341] However, the Council's decision should not be based solely on economics.[342] The Council must also consider reliability needs with respect to transmission, voltage and regulation support, transmission constructability consideration, the benefits of black start capability, and storm restoration considerations when considering a path forward.[343] While the Advisors conclude that the RICE Alternative and the CT Alternative, as modeled, are similarly economically attractive, as between the two, the RICE Alternative is less sensitive to changes in

[340] Movish-1 at 9:13-16.
[341] Rogers-1 at 43:1-45:11.
[342] Rogers-1 at 45:12-14.
[343] Rogers-1 at 45:12-20.

the MISO capacity market prices, has a better heat rate, and operationally provides more dispatch flexibility.[344]

Under the economic analyses modeled either with or without the Council's 2% DSM Goal, there is not much difference between the RICE Alternative and the CT Alternative.[345] However, the RICE Alternative is a better fit with ENO's load and capability needs, especially when considering the Council's 2% DSM Goal.[346] There are two additional factors that must be considered as well: (1) the level of certainty in the capital cost estimates, and (2) several physical parameters of the RICE Alternative that potentially make it operationally more attractive to the Council.[347] With respect to the capital cost estimates, the estimates for the RICE Alternative and the CT Alternative are fairly certain and based upon negotiated Engineer, Procure, and Construct ("EPC") contracts.[348] On the other hand, the transmission cost estimates are based on generic high-level cost per mile-based estimates rather than a cost estimate based on a specific design.[349] The uncertainty in the transmission capital cost estimates is a concern that should be considered as well.[350] In short, the RICE Alternative presents a lesser economic risk than either the CT Alternative or the Transmission Alternative because its capacity is more aligned with ENO's forecasted capacity needs than are both the CT Alternative, which offers more capacity than ENO needs in the near term and the Transmission Alternative, which offers no new capacity.[351] With respect to the physical parameters of the RICE Alternative, the RICE Alternative is expected to operate at a lower capacity factor than the CT Alternative, would be dispatched in a

[344] Vumbaco-1 at 26:13-16; Rogers-1 at 51:5-19.
[345] Rogers-1 at 51:5-19.
[346] Rogers-1 at 51:5-19.
[347] Rogers-1 at 46:1-7, 51:5-19.
[348] Rogers-1 at 46:8-14.
[349] Rogers-1 at 46:8-14.
[350] Rogers-1 at 46:8-14.
[351] Vumbaco-1 at 25:3-7.

more economic operating mode than the CT Alternative, the RICE unit is more flexible with respect to commitment and dispatch and was a better fit for the generation needs of the region, the RICE Alternative can more precisely match part load requirements and can most likely be dispatched with the RICE Alternative engines operating at or near their most efficient operating points.[352] At its full load operation, the RICE Alternative has a heat rate that is roughly 18% better than the CT Alternative, therefore it would have lower per MWh fuels costs as well as being less susceptible to fuel price risk.[353]

If selected, the RICE Alternative also would provide other significant benefits to New Orleans, including operational flexibility, dynamic system support for voltage regulation, on-site black start capacity to support restoration of service after a major outage or storm event, and the ability to provide a source of power to ENO's critical loads in the event of an outage.[354] Further, as noted above, 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.[355]

Of the two NOPS configurations, the Council should strongly consider favoring the 128 MW RICE Alternative, due to its better fit with ENO's load and capability needs, especially when considering the Council's 2% DSM Goal, superior heat rate, operational flexibility, and black start capability in the event that New Orleans becomes disconnected from the regional transmission grid.[356] An additional benefit of the RICE Alternative is that it can locally black

[352] Rogers-1 at 46:15-47:18.
[353] Rogers-1 at 46:15-47:18, 51:5-19.
[354] Movish-1 at 4:21-5:3.
[355] Movish-1 at 5:3-5; Vumbaco-1 at 24:3-13.
[356] Rogers-1 at 3:10-15; 51:5-19.

start (*i.e*. without resources outside of the Michoud site), so it offers a substantial benefit compared to the CT Alternative.[357]

When considering the MISO capacity market, transmission constructability uncertainty operation, and economic risk to ratepayers, the generation alternative that best hedges and partially mitigates such risk is the construction of the RICE Alternative in combination with the incorporation of renewable technologies and realistically achievable DSM potential in ENO's service territory.[358]

The operational characteristics of the RICE Alternative, in particular the RICE Alternative's local black start capability would serve to reduce risks to New Orleans under certain adverse weather events.[359] Neither the CT Alternative nor the Transmission Alternative offers this capability.[360] If the RICE Alternative is not built, the closest black start capability to New Orleans is 40-50 miles upriver, meaning that if the system is islanded and in complete blackout, the 40-50 mile transmission line to that resource would have to be repaired before the city could be re-electrified.[361] Additionally, as compared to the wind or solar-based alternatives (aside from their questionable locational assumptions), the RICE Alternative provides dispatchable capacity, which is not at risk due to the intermittent availability of wind or solar irradiance.[362]

After fully examining the testimony and discovery submitted in this case and performing an independent analyses thereof, the Advisors conclude that the construction of the RICE

[357] Vumbaco-1 at 24:1-2.
[358] Vumbaco-1 at 8:7-12.
[359] Vumbaco-1 at 27:17-28:20; Rogers-1 at 51:5-19.
[360] Vumbaco-1 at 27:17-28:20.
[361] Hr'g Tr. 12/15/17, 214:22-215:7.
[362] Vumbaco-1 at 27:17-28:20.

Alternative in combination with the incorporation of renewable technologies and realistically achievable cost effective DSM potential in ENO's service territory is in the public interest.

C. <u>**WHETHER ENO APPROPRIATELY CONSIDERED A FULL RANGE OF OPTIONS TO MEET THE IDENTIFIED NEED**</u>: In light of the very specific reliability need identified, ENO has considered a reasonable range of options. The other options urged by Intervenors would not sufficiently address the identified needs.

While more data is generally preferable when making decisions based on highly technical information, and a more extensive use of the AURORA model's optimizations functions would have been beneficial, the Advisors believe that the Council has enough information before it to render a decision in this case, particularly in light of significant, ongoing risk to ratepayers which will only be exacerbated by further delay. ENO has identified a reasonable range of options to meet the specific identified needs in this case, and the Council now has enough information to render a decision on ENO's application.

While an IRP process was not performed as part of ENO's application, ENO's application was significantly informed by the analysis it performed in its 2015 Final IRP. As part of its 2015 IRP, ENO performed a technology assessment in which ENO screened a wide range of generation technologies to define a set of reference supply-side generation technologies that would be modeled in the IRP process.[363] The final set of supply-side generation technologies included: pulverized coal generation, combustion turbines, combined cycle gas turbines, internal combustion engines, generation from biomass, nuclear, wind, solar, and battery storage.[364]

[363] Rogers-1 at 14:4-9.
[364] Rogers-1 at 14:4-9.

The need for some level of generation in the City has long been known to ENO and the Advisors, and was certainly identified in the 2015 IRP process. In fact, the preferred portfolio identified in ENO's 2015 Final IRP analysis included a 250 MW CT, which is consistent with ENO's 226 MW CT Alternative. The reduction in size and change in technology that led to the RICE Alternative proposal was due largely to the availability of new data acquired and analyses performed since the close of the 2015 IRP process. ENO's analyses in both the 2015 Final IRP and in this docket are further informed by the input from the Advisors that the initial analyses needed to be supplemented to make sure the Council has enough information to make a decision.

With regard to peaking technologies modeled in the IRP, ENO included six different internal combustion engine CT technologies ranging from 19 MW to 194 MW.[365]

ENO ran the AURORA optimization process in the 2015 IRP and it chose a 382 combined cycle gas turbine ("CCGT") in three of the four scenarios run and 1,150 MW of solar with 50 MW of wind in the fourth scenario run.[366] ENO did not choose a CCGT, however, instead chose a 194 MW CT unit for its preferred portfolio, arguing that such a unit was better suited to meet the peaking power need identified in the IRP than a CCGT.[367] In performing additional production cost analyses at the request of the Advisors and Intervenors, ENO abruptly increased the size to a 250 MW CT.[368]

Neither the size nor the timing of the project was optimized as part of the IRP process.[369] The size of the CT Alternative evolved from ENO's initial selection of a 194 MW CT outside of

---

[365] Rogers-1 at 14:9-11.
[366] Rogers-1 at 14:16-15:24.
[367] Rogers-1 at 14:16-15:24.
[368] Rogers-1 at 16:4-13.
[369] Rogers-1 at 17:11-18:2.

the AURORA optimization process in the IRP process.[370] The size of the RICE alternative appears to be a result of the evaluation of options slated for consideration in a WorleyParsons study performed for ENO regarding peaking units in the 100 MW to 150 MW size range.[371] The timing was originally chosen by ENO, as well, and appears to have been based on the timing of the optimized selection of the CCGT resource.[372] The current timing of either the CT or the RICE Alternative appears to be "as soon as possible" based upon the anticipated schedule durations for each of the alternatives.[373] This suggests that ENO cannot solely rely on the economic analyses presented in the IRP to demonstrate a case for the NOPS unit.[374]

ENO has provided three sets of economic analyses in this proceeding: one set with the Initial Application, one set as part of the supplemental testimony and one set with the Supplemental Application.[375] The Initial Application generally provided a screening analysis of CT Alternatives.[376] The supplemental testimony was required by Council Resolution No. R-16-506 and in response to a September 19, 2016 request by the Council's Advisors for ENO to perform additional AURORA IRP modeling to assist the Council in determining whether the construction of NOPS is necessary and in the public interest.[377] Lastly, the analyses included with the Supplemental Application were also developed utilizing the AURORA production cost modeling software and were, in part, informed by the Advisors' recommendations.[378]

[370] Rogers-1 at 17:11-18:2.
[371] Rogers-1 at 17:11-18:2.
[372] Rogers-1 at 17:11-18:2.
[373] Rogers-1 at 17:11-18:2.
[374] Rogers-1 18:7-8.
[375] Rogers-1 18:11-19:3.
[376] Rogers-1 18:11-19:3.
[377] Rogers-1 18:11-19:3.
[378] Rogers-1 18:11-19:3.

The Advisors made their September 19, 2016 request that ENO perform additional analyses because the Advisors believed that over the 20 months it had taken ENO to perform the 2015 IRP and in the time since the 2015 Final IRP was filed, several important developments had occurred that were not reflected in the 2015 Final IRP analysis.[379] Specifically, (1) the acquisition of Algiers; (2) the Council's expression of its 2% DSM Goal; (3) the increase in size of the Union acquisition; (4) the suggestion that there may be a Transmission Alternative to the installation of NOPS; (5) the revised, dramatically different load forecast; (6) the commitment by ENO to pursue AMI; and (7) ENO's commitment to seek up to 100 MW of renewables.[380] The Advisors felt that all of these developments and changes could result in material increases in costs to ratepayers and could alter the ultimate decision of the Council with respect to the Project.[381] The Advisors requested the alternate case analyses to ensure that the Council had additional current information to inform their decisions on the NOPS proposal and other issues in the near term - decisions that could likely be made prior to the next iteration of the triennial IRP process.[382]

The four additional cases that the Advisors asked ENO to model generally built of what had been the Stakeholder Input Case from the 2015 IRP process with updated assumptions including: (1) a load forecast consistent with the BP16 update; (2) a natural gas price forecast consistent with the BP16 update; (3) an updated CO_2 price forecast; (4) an increase in the renewable capacity to 100 MW; (5) inclusion of the effects of planned and recently completed

[379] Rogers-1 at 19:3-21:2.
[380] Rogers-1 at 19:3-21:2.
[381] Rogers-1 at 19:3-21:2.
[382] Rogers-1 at 19:3-21:2.

transmission upgrades; and (6) inclusion of the effects of any planned new generating resources including the proposed St. Charles Power Station.[383]

Each of the four alternate cases was designed by the Advisors to isolate the impact of an individual decision by changing only one assumption against a common base case so that the cost impact of that individual decision could be identified.[384] The three decisions points to be tested in the Advisors requested cases were (1) NOPS versus transmission upgrades; (2) pursuit of the 2% DSM Goal; and (3) impact of AMI on DSM.[385] However, after reviewing the results of the analyses performed by ENO in response to the request, the Advisors do not recommend that the Council rely upon the outcome of these analyses because (1) they cannot be directly compared to the analyses presented in the Supplemental Application due to the change in the load forecast; (2) they do not contain a scenario with the RICE Alternative; and (3) they only partially considered the Council's 2% DSM Goal due to ENO's choice to use a breakeven analysis that calculated the level of DSM investment that would result in the same net present value as the base case, rather than analyzing a full implementation of the 2% DSM Goal.[386]

The Advisors provided further input to ENO prior to its filing of the Supplemental Application as to the minimum level of analysis that should be included in that application.[387] The Advisors sought to ensure that ENO provided the Council with a 20-year economic analysis that (1) included current and consistent assumptions including the Council's 2% DSM Goal; (2) was based on utilizing the AURORA optimization engine and included at least two optimized portfolios with one being the re-sized NOPS alternative (in this manner the Council would have

[383] Rogers-1 at 21:3-13.
[384] Rogers-1 at 21:14-23:20.
[385] Rogers-1 at 21:14-23:20.
[386] Rogers-1 at 21:14-23:20.
[387] Rogers-1 at 24:11-20.

a least cost optimized portfolio to compare with the NOPS proposal); (3) included sensitivities that addressed fuel costs and capacity prices, and (4) included the associated transmission load flow analyses consistent with the economic analyses.[388] This analysis was designed to partially mimic a portion of the IRP optimization process.[389] However, ENO only partially adhered to the Advisors' recommendations.[390] The results presented in ENO witness Cureington's Supplemental and Amending Direct Testimony as "requested portfolios" are not actually what the Advisors requested, nor are they based on optimization analyses.[391]

In response to the updated load forecast, ENO engaged WorleyParsons to conduct a study regarding the Company's potential options for a smaller resource.[392] The Company looked at potential combustion turbine and RICE alternatives with a net plant output between 106 MW and 128 MW and ultimately concluded that the currently proposed 128 MW RICE alternative had the lower levelized cost of electricity on a $/MWh basis as well as other benefits such as low water usage, a low emissions profile, the ability to support renewable resources, and black start capability.[393]

Thus, the initial analysis indicating that a CT resource should be added to ENO's portfolio was performed in the 2015 IRP process, but the actual proposal before the Council has been informed by a significant additional amount of analysis and new information that has since become available. This is appropriate, and indeed necessary. The IRP is not, and never has been, meant to be a process that gathers sufficient data to approve or deny the acquisition of any

[388] Rogers-1 at 24:11-20.
[389] Rogers-1 at 24:11-20.
[390] Rogers-1 at 25:3-8.
[391] Rogers-1 at 25:3-8.
[392] Rogers-1 at 17:2-7.
[393] Rogers-1 at 17:2-7.

specific resource. Rather, under the rules in place at the time the Initial Application was filed, the IRP process was intended to provide a framework to help guide ENO in its decisions to (1) develop generation resources and purchase power both individually and in conjunction with its affiliate Operating Companies pursuant to the System Agreement; (2) develop transmission and distribution facilities both individually and in conjunction with its affiliate Operating companies pursuant to the System Agreement; (3) develop and deploy demand-side resource options and (4) incorporate into its planning process the results of energy efficiency programs developed at the direction of the Council (*e.g.*, Energy Smart New Orleans and others as may subsequently be determined to be applicable).[394] There has never been a requirement that any specific resource acquisition precisely match the IRP results, rather the IRP rules in effect for the 2015 Final IRP provided that "The Council will consider the Utility's IRP status reports, implementation of the requirements and the Utility's success in achieving its objectives in rate-making proceedings that address among other things the prudency of costs incurred by the Utility to construct generation, and purchase and deliver electricity."[395] Moreover, as discussed above, the Council's resolution regarding the 2015 Final IRP was very clear that acceptance of the 2015 Final IRP Report by the Council would not constitute binding precedent in this case. The Council's new IRP Rules approved in 2017 are even more explicit that acceptance of an IRP does not constitute approval of any specific resource:

> The Council's acceptance of the Utility's IRP as described herein shall have no precedential effect with respect to the Council's evaluation of any application for approval of the acquisition,

---

[394] Resolution No. R-10-142 at 6.

[395] Electric Utility Integrated Resource Plan Requirements of the Council of the City of New Orleans, Attachment to Resolution No. R-10-142, at 7.

> implementation, or deactivation of any supply-side or demand-side resource or program.[396]

The Joint Intervenors argue that the Transmission Alternative to NOPS will address the transmission system deficiencies at a considerably lower capital cost than NOPS, and that ENO has not given thorough consideration to adding transmission capacity as an alternative to building NOPS.[397] Joint Intervenors witness Lanzalotta argues that ENO has not yet seriously studied the rebuild of the five existing transmission lines it says are needed for system reliability if no generation is built at NOPS.[398] He states that the Company doesn't know if any new transmission rights of way will be needed or to what extent the existing transmission line towers will have to be rebuilt.[399] Notwithstanding, Mr. Lanzalotta admits that he conducted no independent analysis or study regarding any aspect of the feasibility of competing the transmission upgrades.[400]

Joint Intervenor witness Fagan argues that transmission reinforcement to meet NERC reliability requirements is feasible and more cost-effective than building a new gas-fired power plant.[401] Fagan also argues ENO's updated load forecast and updated power flow analyses have led to a reduction in the number of transmission reinforcements required.[402] Fagan also speculates that other steps could be taken to reduce peak load on the system over time, which can have a material effect on the timing requirements for any require transmission reinforcements and ease outage scheduling difficulties.[403] However, Fagan admitted on cross-examination that

---

[396] Electric Utility Integrated Resource Plan Rules of the Council of the City of New Orleans, Attachment B to Resolution No. R-17-429, at 14.
[397] Lanzalotta-1 at 2:19-3:2.
[398] Lanzalotta-1 at 10:17-11:2.
[399] Lanzalotta-1 at 10:17-11:2.
[400] Hr'g Tr. 12/21/17, 76:7-24.
[401] Fagan-1 at 5:10-6:15; 36:18-38:11.
[402] Fagan-1 at 35:2-36:1
[403] Fagan-1 at 35:2-36:1

when he prepared his testimony, he had not done any studies to determine the feasibility of outage scheduling for transmission lines into the ENO service area for the next ten years, and that he has never planned or operated transmission in MISO South, so his speculation as to how easily transmission upgrades can be accomplished appears to lack any foundation.[404]

There is simply not enough evidence in the record to demonstrate that the Transmission Alternative is viable. The Advisors have significant concerns that the Transmission Alternative is likely significantly more expensive than ENO estimated, and that it will take much longer to solve the transmission reliability issue through transmission upgrades than through adding local generation such as the RICE Alternative.

ENO witness Cureington testified that portfolios that involve building transmission alone and/or adding renewable capacity are not viable planning alternatives to building a local, dispatchable peaking resource.[405] Although Mr. Cureington's analysis showed that the Transmission Alternative was the most cost-effective option in in the reference and high gas models with the 60% MISO capacity cost assumption and the second most cost-effective in all other scenarios,[406] he testified that he believes that the Total Relevant Supply Costs are understated because his calculations only include transmission upgrades to maintain NERC reliability requirements and do not address either the additional resources required to meet the identified needs of ENO's customers, or market and supply risks.[407] He argues that the

[404] Hr'g Tr. 12/19/17, 32:3-15.
[405] Cureington-5 at 5:10-13.
[406] Cureington-5 at 28:4-29:8.
[407] Cureington-5 at 29:9-31:15.

Transmission Alternative leaves New Orleans too dependent upon transmission to serve the needs of its customers.[408]

Advisors' witness Rogers did conclude that of the cases modeled, the economically preferred alternative appears to be construction of transmission upgrades and 100 MW of solar capacity instead of constructing NOPS.[409] However, Rogers went on to emphasize that the Council should not base its decision in this docket solely on economics and that he believes that reliance on this Transmission Alternative poses potentially excessive risk to ENO's customers.[410] If the Council determines it will not approve either the CT Alternative or the RICE Alternative, Movish cautioned that the Transmission Alternative should not be considered as a realistic alternative until such time as ENO files additional information with the Council.[411]

The timing, and cost of completion of the necessary transmission upgrades required to resolve ENO's NERC system reliability violations is uncertain.[412] Further detailed evaluations and cost estimates would be needed prior to final Council approval of such an option, and the Council should consider the current risk of system reliability occurrences that could persist until the transmission upgrades were complete and weigh this risk as compared to the RICE Alternative and the CT Alternative whose construction completion dates can be comparatively and reliably forecasted and whose costs are comparatively much more known.[413] Advisors witness Vumbaco recommended that, should the Council chose the Transmission Alternative to address the reliability problems that exist today and are expected to continue in the future unless

---

[408] Cureington-5 at 29:9-31:15.
[409] Rogers-1 at 3:1-9; 50:4-51:4.
[410] Rogers-1 at 3:1-9; 50:4-51:4.
[411] Movish-1 at 47:3-9*; see also*, Rogers-1 at 3:1-9; 50:4-51:4.
[412] Vumbaco-1 at 27:9-16.
[413] Vumbaco-1 at 27:9-16.

corrected, more information regarding the viability of this alternative is needed and the Council should immediately direct ENO to : (i) file with the Council information demonstrating that a transmission only solution to the reliability problems is realistically achievable; (ii) that its proposed upgrade projects can be constructed, (iii) the realistic timing of each project, (iv) the potential impacts of the project(s) delay on ENO's transmission reliability, and (v) the definitive costs for each project within the ensuing six to nine months for its evaluation and final approval prior to its implementation.[414]

Alternatives that rely on transmission upgrades may be technically feasible, however, the Advisors have significant concerns regarding the constructability of the Transmission Alternative's transmission upgrades.[415] The Advisors are also concerned that ENO is uncertain of the feasibility of constructing such transmission upgrades in terms of time and money.[416] At some point delayed action (*i.e.* the uncertain timing of the completion of the transmission upgrades) presents the same risks to New Orleans as does inaction (*i.e.*, the unacceptable risk constituted by a "do nothing" approach).[417] The Council should carefully weigh the risk to New Orleans related to potential delays in implementing alternatives based on transmission.[418] While the Transmission Alternative may be the most economically attractive, it carries significant risks that should be quantified when compared to the CT or RICE Alternatives.[419]

In addition to the doubtful nature of whether the Transmission Alternative can actually be implemented in time to prevent a significant outage, it would not be prudent to rely on the MISO

[414] Vumbaco-1 at 7:1-7.
[415] Vumbaco-1 at 23:1-14; Movish-1 at 26:13-14, 46:15-47:24.
[416] Vumbaco-1 at 23:1-14; Movish-1 at 26:10-13, 46:15-47:24.
[417] Vumbaco-1 at 23:1-14; Movish-1 at 25:12-26:2, 26:10-13; 28:30-29:1.
[418] Vumbaco-1 at 23:1-14; Movish-1 at 29:4-6, 48:5-9.
[419] Vumbaco-1 at 25:7-13.

capacity market to address ENO's long-term capacity needs.[420] While the Joint Intervenors argue that ENO should rely upon the MISO capacity market to meet long-term reliability needs, their argument is based on speculation that future MISO capacity market prices will stay low that is as unfounded as ENO's speculation that prices will escalate rapidly. Joint Intervenors witness Fagan argues that ENO understates MISO's resource surplus and overstates MISO's future capacity prices, obscuring the substantial economic risk to New Orleans ratepayers of building a new gas plant that is not needed.[421] However, Fagan admitted upon cross-examination that in recommending a transmission-only option with reliance on the MISO capacity market to meet capacity needs, he was not familiar with and did not address or do any analysis of narrow constrained areas within MISO South.[422] Fagan also did no studies to determine the feasibility of outage scheduling for transmission lines into the ENO service area for the next ten years.[423] Joint Intervenors witness Stanton argues that ENO could meet its MISO capacity and NERC transmission obligations by purchasing market capacity and that transmission upgrades are less expensive than and provide more resilience than building NOPS.[424] However, Dr. Stanton admitted in cross-examination that she has no training or experience in transmission system planning or utility operations, leaving one to wonder upon what she has based her opinion.[425] Further, neither Fagan nor Stanton has done any independent projection of MISO capacity prices,[426] nor have they done any independent analyses regarding the feasibility of the transmission-only solution.[427]

---

[420] Rogers-1 at 31:1-2, 15-20, 32:1-7.
[421] Fagan-1 at 4:4-5:9; 16:13-32:19.
[422] Hr'g Tr. 12/19/17, 31:10-19.
[423] Hr'g Tr. 12/19/17, 32:7-12.
[424] Stanton-1 at 7:9-11; 35:6-8; 44:1-7.
[425] Hr'g Tr. 12/21/17, 11:19-22.
[426] Hr'g Tr. 12/19/17, 30:3-19, 31:1-9, Hr.g Tr. 12/21/17, 13:3-15.
[427] Hr.g Tr. 12/19/17, 32:6-15; Hr'g Tr. 12/21/17, 26:4-9.

ENO witness Cureington argues that purchases from the MISO capacity markets do not mitigate the local reliability risk.[428] This combined with the financial risk, means continued reliance on MISO's capacity markets is a risky gamble and would expose customers to congestion risk in the energy market as well.[429] He states that the MISO capacity market also has a risk of price separation between zones, which is a problem where LSEs, like ENO, that do not own or contract for enough generating capacity located in the same zone as their load.[430] In addition, he argues, it is not reasonable to assume the lower, 60% MISO prices, which reflects the Intervenors' request to use a capacity price forecast that is net CONE, which is not reasonable because it is not the methodology used by MISO to calculate prices, and it is arbitrary.[431] Cureington concludes that relying upon MISO capacity markets is not a reasonable option.[432]

It would not be appropriate to rely on the MISO PRA market to meet long-term resource needs. A regulated LSE should strive over the long term to acquire the appropriate mix of resource types (baseload, intermediate, and peaking) that match the LSE's expected load profile and rely on the MISO markets to meet limited short-term differences in resources and loads.[433] ENO should acquire resources to match load requirements over the long term.[434] The PRA should generally be used to meet limited short-term differences in resources consistent with what the Company has argued.[435]

---

[428] Cureington-5 at 17:10-14.
[429] Cureington-5 at 17:10-14.
[430] Cureington-5 at 23:6-24:15.
[431] Cureington-5 at 39:8-41:10.
[432] Cureington-5 at 16:20-17:14.
[433] Rogers-1 at 32:1-8.
[434] Rogers-1 at 32:1-8.
[435] Rogers-1 at 34:1-12.

If the Joint Intervenors are correct as to the projected capacity prices remaining low, then the risk to ratepayers is that they will pay too much for ENO to build capacity, when they could have gotten cheaper capacity from the market. If ENO is correct in its assumptions, however, ratepayers are subject to the risk of high prices for capacity in the market, and they are also subject to the risk of cascading outages and/or load shedding. The Advisors' assessment is that it is more risky to rely on the MISO capacity market for long-term planning needs than to build generation.

The Joint Intervenors also argue that ENO has not examined a sufficient number of other options, such as meeting its capacity and reliability needs through increased investment in energy efficiency and DSM, DG, renewables, and battery storage.[436] They argue ENO should have analyzed additional scenarios, including one that incorporates the most cost-effective levels of energy efficiency, one that assesses a higher-efficiency scenario combined with the lower estimate of the MISO capacity market's future clearing prices, one with additional solar PV beyond the initial 100 MW in combination with the most cost-effective energy efficiency portfolio; one that would defer or eliminate some of the required transmission reinforcement needs indicated under its reference portfolios, and one that in the near future could include bulk system battery storage resources.[437] They also argue that the resources can help meet peaking needs by reducing overall demand.[438]

The Advisors do not find the Joint Intervenors' witnesses to be compelling. In cross-examination Fagan admitted that when he prepared his testimony in this case, he had not

[436] Stanton-1 at 6:12-14; 25:1-26:11; 26:12-27:8; 27:9-28:3; Luckow-1 at 25:13-26:2; Fagan-1 at 4:4-5:9; 6:16-7:8; 7:9-16; 7:19-8:5; 10:15-12:3 14:3-15:23; 16:1-12.

[437] Fagan-1 at 12:4-14:2.

[438] Fagan-1 at 24:15-25:1; Stanton-1 at 26:12-27:8.

reviewed ENO's 2015 IRP or any materials from that proceeding.[439] He also had not (1) run any AURORA production cost models, capacity expansion modeling packages or power flow modeling, (2) performed any economic analysis demonstrating the cost impact to ENO's customers of the different possibilities he mentions; (3) actually propose any specific basket of resources to meet the identified needs, (4) perform an analysis of how much DSM should be achievable in New Orleans, (5) did not analyze the amount of solar capacity that can be located in New Orleans or the DSG load pocket, (6) did not do an independent study to forecast solar PV costs or the expected installation rate of solar in New Orleans, (7) he could not place a specific number on the amount of DSG that could be guaranteed to be achieved in New Orleans (8) any analysis on the feasibility of installing 200 MW of solar in New Orleans, (9) any analysis of the economic viability of battery storage in MISO, and (10) did not analyze how actions that ENO takes would lower the load or additional transmission investment would mitigate against the contingencies they're concerned about.[440] When asked if he would guarantee that renewables and DSM alone would keep the lights on in New Orleans in the event that a storm takes out the transmission grid and leaves New Orleans electrically islanded, Fagan replied, "No. nobody could."[441] He also admitted that behind-the-meter solar is not particularly likely to be able to support storm restoration.[442] It is clear that the Joint Intervenors' witness Fagan was not familiar with what options ENO had considered through the 2015 IRP process, nor did he recommend any specific basket of resources, nor had he done any relevant analysis to determine what is actually feasible in New Orleans or at what cost.

---

[439] Hr'g Tr. 12/19/17, 16:20-25.

[440] Hr'g Tr. 12/19/17, 17:22-13, 19:15-23, 21:2-13, 22:8-13, 23:3-6, 25:15-19, 26:6-14, 35:4-23, 35:25-36:6, 36:7-18, 36:19-24, 41:13-25

[441] Hr'g Tr. 12/19/17, 37:10-16.

[442] Hr'g Tr. 12/19/17, 38:3-6.

Joint Intervenor witness Stanton argues that investment in utility-scale solar (beyond the 100 MW already committed to and behind-the-meter solar investments would reduce capacity need by reducing peak load requirements and that battery storage should also be accounted for.[443] She argues that the best generation and transmission system in the world cannot serve customers over broken poles and wires.[444] The City Council currently awaits an assessment of electric distribution system reliability.[445] She also recommends that the City Council wait until it has all information at hand before making its decision regarding NOPS.[446] It should have the results of a competitive procurement process, and the expected DSM potential study and reliability assessment.[447]

However, Dr. Stanton admitted on cross-examination she had not done any analysis of her own demonstrating whether the 2 % DSM Goal is an achievable goal.[448] Dr. Stanton agreed on cross-examination that if you decrease your load forecast to account for a particular DSM forecast and that DSM forecast does not materialize, customers would be exposed to capacity market price risks.[449] She also admitted that the level of savings from AMI is uncertain.[450]

Dr. Stanton admitted she does not know the location of any of the potential 100 MW of renewables ENO plans to add.[451] She also admitted she had not performed any analysis of the expected solar installation rates in New Orleans over the next 20 years or any analysis of the projected costs of behind-the-meter solar in New Orleans, and was not familiar with ENO's net

---

[443] Stanton-1 at 26:12-27:8; 27:9-28:3.
[444] Stanton-1 at 7:12-14.
[445] Stanton-1 at 7:12-14.
[446] Stanton-1 at 7:19-8:2.
[447] Stanton-1 at 7:19-8:2.
[448] Hr'g Tr. 12/21/17, 28:2-6.
[449] Hr'g Tr. 12/21/17, 28:7-13.
[450] Hr'g Tr. 12/21/17, 21:25-22:3.
[451] Hr'g Tr. 12/21/17, 22:12-15.

metering rate schedule.[452] She admits that she has no analysis to support the trajectory of behind-the-meter solar growth that she calculated in her Figure 7.[453] She also admits that she did not perform an analysis with respect to the duration that behind-the-meter or utility scale battery storage could provide capacity when needed.[454] Dr. Stanton also admitted that she did not perform an analysis of the potential costs of either behind-the-meter solar or utility scale battery storage over the 20-year planning horizon, and had not analyzed the capacity that either could provide.[455] Stanton has not done any analysis of the amount and price of capacity that might be available for ENO for wind power purchase agreements ("PPAs"), whether transmission would be available to import remote wind resources, and does not offer an opinion as to whether importing remote wind capacity into New Orleans would support reliability in the DSG load pocket.[456] Stanton agrees that investment in the distribution system is not a viable alternative to addressing ENO's capacity needs.[457] Finally, she stated that she did not propose any specific alternative portfolio of resources for the Council to consider.[458] In short, Dr. Stanton offers no viable plan to the Council to meet the identified reliability and capacity needs, she merely offers speculation unsupported by any analysis of what is feasible and achievable in New Orleans as to other options that she thinks might work.

The Advisors do not believe that the specific reliability and peaking capacity needs at issue in this proceeding, including NERC P6 contingencies, can be met by these types of resources, and thus, believe ENO has sufficiently evaluated such resources for the purpose of

---

[452] Hr'g Tr. 12/21/17, 23:14-24:4.
[453] Hr'g Tr. 12/21/17, 24:11-20.
[454] Hr'g Tr. 12/21/17, 25:17-22.
[455] Hr'g Tr. 12/21/17, 24:24:22-25:16.
[456] Hr'g Tr. 12/21/17, 25:23-26:18.
[457] Hr'g Tr. 12/21/17, 27:8-11.
[458] Hr'g Tr. 12/21/17, 20:16-21.

meeting this identified need. The Advisors note that ENO does continue to examine and pursue such resources, and has committed to adding 100 MW of renewables to its portfolio, but these resources cannot offset the need for local, dispatchable, all-weather generation.

ENO argues that it has conducted sufficient analysis of alternatives to NOPS. ENO conducted AURORA production cost modeling of three reference cases across sensitivities for natural gas and MISO capacity prices.[459] Case 1 was the RICE Alternative. Case 1G was the CT Alternative, and Case 2 was the Transmission Alternative.[460] All three cases include the Business Plan 17 Update (BP17U) forecast of load and commodity prices including reference CO2, 100 MW of solar continuation of Energy Smart and full deployment of AMI.[461] Sensitivities were conducted using low and high gas prices and 60% of the MISO capacity price forecast. The results were then incorporated into the Total Relevant Supply Cost Analysis.[462] The Advisors also requested that ENO run three requested portfolios to model certain assumptions advanced by the Intervenors.[463] Although it was requested that ENO use AURORA's capacity expansion model, instead, ENO attempted to simulate the results of the capacity expansion feature.[464] Accordingly it conducted AURORA modeling on four portfolios using inputs and assumptions requested by the Advisors on behalf of the Intervenors.[465] The first portfolio (Case 3) evaluates the RICE, the second one (Case 3G) evaluates the CT.[466] The third one (Case 4A) evaluates adding 100 MW solar, and the fourth one (Case 4B) evaluates adding

[459] Cureington-5 at 27:1-29:8.
[460] Cureington-5 at 27:1-29:8.
[461] Cureington-5 at 27:1-29:8.
[462] Cureington-5 at 27:1-29:8.
[463] Cureington-3 at 31:18-33:11.
[464] Cureington-3 at 31:18-33:11.
[465] Cureington-3 at 31:18-33:11.
[466] Cureington-3 at 31:18-33:11.

300 MW of wind.[467] They all included the BP2017U load forecast adjusted for the estimated impact of the 2% DSM Goal, the planned 100 MW of solar, and full deployment of AMI.[468] They also ran the same sensitivities using low and high gas prices and the 60% MISO price forecast.[469] However, ENO argues, the Requested Portfolios included an assumption of attaining the 2% DSM Goal, which is not likely to be attainable, and would not be cost-effective, as is demonstrated by the Navigant report.[470] ENO witness Cureington also testifies that renewable resources are intermittent and need to be backed up by traditional resources.[471]

Regarding DSM resources, Mr. Cureington testifies that insufficient cost-effective incremental DSM programs are available beyond the Company's currently approved Energy Smart programs to meet the entirety of its long-term needs.[472] He argues that the achievable amount of DSM in New Orleans constitutes only approximately 14% of ENO's projected need for long-term peaking and reserve capacity by 2019. Navigant concluded that, under an aggressive scenario, ENO could potentially reduce forecast sales by roughly 17% over the next 20 years, which averages to 0.85% per year. [473]

Among the Requested Portfolios run in his analysis, Mr. Cureington states that the wind portfolio was the least cost-effective portfolio in all sensitivities, solar was the most cost effective when assuming reference or high gas prices and the 60% MISO capacity costs and in the other sensitivities, solar came in second or third.[474]

---

[467] Cureington-3 at 31:18-33:11.
[468] Cureington-3 at 31:18-33:11.
[469] Cureington-3 at 31:18-33:11.
[470] Cureington-5 at 35:4-39:6.
[471] Cureington-5 at 15:12-16:4.
[472] Cureington-5 at 16:5-19.
[473] Cureington-5 at 16:5-19.
[474] Cureington-5 at 34:1-35:3.

Mr. Cureington argues that renewables are intermittent, limiting ENO's ability to rely on them to meet customer demand.[475] The greatest potential for wind resources lies in areas remote from ENO's service area, requiring significant transmission upgrades to deliver those resources to New Orleans.[476] Also, wind tends to peak in the late evening and early morning hours, which does not match up with ENO's peak.[477] Solar installations can require 7-10 acres of land per MW.[478]

In addition, ENO witness Charles Long testified that "[w]e did not study what other utilities were doing in terms of how it related to our needs. We did our own analysis, performed our own assessments, and battery storage is just not -- because of its intermittency, it's not going to solve our reliability problems. . . . Well, I know if a generator can only make power for four -- or a battery can make power for four hours and I have an outage longer than four hours, that it won't work, and I routinely have outages much longer than four hours."[479]

While the Advisors appreciate the desire of the Joint Intervenors to encourage ENO to acquire a greater percentage of its energy from renewable resources, natural gas is needed to back up those renewables and offset their intermittency to keep the grid stable and reliable. Natural gas resources enable greater integration of renewables into the system. Even Joint Intervenor witness Fagan stated that customers benefit from natural gas generation, that most anticipated firm additions in MISO over the next 10 years will be gas generation, and that natural

---

[475] Cureington-5 at 42:5-43:12.
[476] Cureington-5 at 42:5-43:12.
[477] Cureington-5 at 42:5-43:12.
[478] Cureington-5 at 42:5-43:12.
[479] Hr'g Tr. 12/15/17, 213.

gas fired capacity will continue to be an important part of the U.S. energy mix for the foreseeable future.[480]

The Advisors believe that relying upon the analysis in this case as evidence that the identified capacity and reliability needs of New Orleans can be met through a combination of transmission upgrades and other resources such as renewables, DG, energy efficiency, DSM and battery storage is unreasonable and too risky.

ENO has employed inconsistent peak load assumptions as between its transmission studies and economic studies when considering the amount of DSM peak load reductions which would occur with the continued implementation of the Council's 2% DSM Goal and the appropriate capacity factor of any potential solar generation.[481] Such inconsistent assumptions can affect the actual load to be served in the transmission studies in the range of 48.1 MW to 63.1 MW over the period analyzed.[482] ENO's assumption in its transmission planning studies of the installation of 100 MW or 200 MW of solar generation, effectively at Michoud and the varying capacity factors assumed for solar, calls into question the veracity of such studies.[483] It has not been shown that constructing or interconnecting solar capacity at or near the Michoud site is feasible.[484] Mr. Movish's review of ENO's transmission studies indicates that capacity, including solar capacity, must be constructed or otherwise interconnected at the transmission level at or near the Michoud site to beneficially impact ENO's NERC system reliability standards compliance.[485] Mr. Movish has observed that it is not demonstrated in the instant

[480] Hr'g Tr. 12/19/17, 32:23-33:25, 36:25-37:8.
[481] Vumbaco-1 at 6:12-17.
[482] Vumbaco-1 at 6:12-17.
[483] Vumbaco-1 at 6:18-20.
[484] Vumbaco-1 at 22:4-11.
[485] Vumbaco-1 at 22:4-11; Movish-1 at 31:15-32:3.

docket that such solar capacity can be constructed at or near the Michoud site.[486] Further, as discussed by Mr. Movish, ENO has used conflicting solar capacity factor assumptions as between its transmission and economic planning analysis.[487]

Mr. Movish concludes that the feasibility of solar or wind capacity additions to deliver capacity where needed to resolve ENO's NERC system reliability violations (i.e. at or near the Michoud site) is unproven, the Council should give particular consideration to the reality of the assumptions employed in modeling these scenarios as discussed by Mr. Movish and Mr. Vumbaco and weigh the risk associated with these against other alternatives presented.[488] The feasibility of wind capacity to beneficially impact ENO's NERC system reliability standards compliance is undemonstrated because the interconnection of wind capacity at or near the Michoud site has not been shown to be feasible. Mr. Movish notes that certain wind capacity discussed by Intervenors has no transmission path to ENO and therefore would be ineffective in addressing ENO's NERC system reliability standards compliance.[489]

The Joint Intervenors also argue that the Council should not approve NOPS, but should require ENO to conduct a competitive procurement to acquire resources to meet the identified need. Joint Intervenors witness Henderson argues that when facing a substantial procurement decision, such as whether to build a power plant, the Council, the utility, and all stakeholders would benefit from the information an all-source solicitation would provide about the costs and benefits of options.[490] He states that the Council should require an "all source" competitive

[486] Vumbaco-1 at 22:4-11; Movish-1 at 32:6-8.
[487] Vumbaco-1 at 22:4-11; Movish-1 at 15:13-17.
[488] Vumbaco-1 at 26:20-27:4.
[489] Vumbaco-1 at 22:15-20; Movish-1 at 33:22-34:12.
[490] Henderson-1 at 2:7-14:6.

solicitation that seeks information about and proposals from resource alternatives.[491] Dr. Stanton argues that a competitive procurement process would reveal all renewable energy resource proposals that are viable in a market setting, potentially including PPAs for MISO wind resources.[492] Air Products witness Brubaker also argues that a competitive solicitation in the form of a Request for Proposals ("RFP") is an appropriate way to test the market to determine the full range Doing an RFP would inquire of the market what options may be available either in the form of a sale of assets, or from a third-party willing to construct capacity and sell the asset to ENO.[493]

The Advisors do not find these arguments persuasive in the specific context of this case and under the specific circumstances of the need identified by ENO. Dr. Stanton admits that at the time she filed her testimony, she did not know how long it would take or what it would cost to conduct a competitive procurement, or who would ultimately bear the cost of that.[494] She also admitted that an IRP process has the potential to be another method of considering a full set of alternatives.[495] In addition, Henderson testified that "There may also be legitimate reasons a utility or utility regulator might determine not to use a competitive procurement process in certain instances. Small procurements, procurements by small utilities, or procurements with very tight requirements, for example, could warrant different treatment."[496] While the Advisors would also generally prefer that ENO use competitive solicitation processes to acquire resources in this case, the Advisors do believe that the specific reliability needs identified in this case are "very tight requirements" due to the specific geographic needs related to reliability and that there

[491] Henderson-1 at 2:7-14:6.
[492] Stanton-1 at 6:15-7:1; 23:8-24:14.
[493] Brubaker-1 at 3:9-14.
[494] Hr'g Tr. 12/21/17, 30:8-13.
[495] Hr'g Tr. 12/21/17, 30:14-18.
[496] Henderson-1 at 10:7-11.

are a somewhat limited number of resources that would be able to meet such requirements. Thus, a competitive procurement process is not likely to produce substantially more options able to mitigate the specific the reliability concerns than those options already identified by ENO.

III. **WHETHER ENO'S SELECTION OF THE MICHOUD SITE IS REASONABLE**: The Michoud site is a reasonable choice, given the identified need.

A. **The Michoud Location Has Several Advantages**

ENO has identified a specific need for generation resources to be installed in the eastern part of the City in order to alleviate certain identified transmission problems. ENO witness Cureington testifies that ENO no longer has a source of generating capacity inside its service territory that can respond to planned and unplanned events, which increases customers' exposure to locational marginal price ("LMP") in the MISO wholesale energy market.[497] ENO specifically needs generation in the Eastern section of New Orleans and that installing generation to the west would not sufficiently mitigate the need.[498]

For more than 50 years, the Michoud generating station in New Orleans East served as the cornerstone of ENO's operating system. ENO's entire system was designed around the Michoud plant.[499] In June of 2016, ENO made the economic decision to deactivate Michoud based on consideration of maintenance and operational issues.[500] This resulted in the loss to ENO of approximately 781 MW of local capacity.[501] Since at least the 1990s until its deactivation, the Michoud generating station was committed to operation during high load periods due to local area voltage problems, and in the event of electrical system contingencies in

[497] Cureington-5 at 21:3-22:5.
[498] Movish-1 at 25:3-9; *see also* C. Long-3 at 16:16-17:4.
[499] Hr'g Tr. 12/18/17 at 336:4-9.
[500] Rice-1 at 3:7-8.
[501] Rice-1 at 3:8.

the DSG area. Because such a large amount of generation was removed from the Michoud site, when the system has been built around having generation at that specific location, putting some level of generation back at or near that location will help support the system in a manner that putting generation in other locations will not.

To the extent that generation is to be sited in the eastern part of the City in order to maintain reliability to the City, the Michoud site has several advantages that benefit ENO customers, including those customers in New Orleans East. ENO already owns the property, saving customers the cost of acquiring it. The site already has a significant amount of the necessary infrastructure in place, including gas pipelines and transmission and distribution lines running into the site, and administrative building facilities that will result in substantial cost savings. ENO also already has several permits applicable to the site that allow it to streamline its permitting process, and it is in a sparsely populated, industrial area where a plant had previously operated successfully on that site for decades.[502]

In addition, ENO witness Rice argues that the Council should also consider the positive impacts of constructing NOPS. The CT resource would produce significant economic benefits in the form of new business sales, new household earnings, new permanent jobs, and new tax collections, both from its construction and operation. The benefits total hundreds of millions of dollars. A recently completed study of the RICE Alternative found similar benefits from one-time capital expenditures and even greater benefits than the CT from ongoing operational expenditures that will continue to accrue for as long as NOPS is in operation.[503] NOPS will

[502] J. Long-1 at 41:21-42:10; Rice-4 at 16:10-12.

[503] Rice-4 at 18:9-19:5, Exhibit CLR-3 ("Economic Impact on the Orleans Parish and Louisiana Economics of Entergy's Proposed New Orleans Power Station").

benefit all citizens of New Orleans, but not at the disproportionate expense of any group of citizens.[504]

B. Testimony In The Record Indicates That The Proposed Units Will Not Contribute to Additional Subsidence at Michoud and that Flood Risks Have Been Substantially Mitigated

ENO has submitted a technical report into the record, the C-K Report, which addresses the evaluation of groundwater withdrawal and air quality associated with the proposed NOPS.[505] The C-K Report was developed to address concerns raised and to understand how the proposed NOPS might impact subsidence and air quality in New Orleans East.[506] The Report presents analysis, calculations, and references that support the following conclusions regarding groundwater withdrawal and subsidence at the Michoud site:

1. Groundwater withdrawal at the Michoud Plant is not the cause of observed damage to infrastructure in New Orleans East including buildings, roads, and flood protection structures;
2. Groundwater withdrawal associated with the [CT Alternative] will not exacerbate subsidence or cause damage to infrastructure in New Orleans East.[507]

As discussed above, ENO also submitted testimony of Dr. George Losonsky, one of the co-authors of the C-K Report, that concludes that the groundwater withdrawal from the Gonzales-New Orleans aquifer associated with either the CT Alternative or the RICE Alternative will not exacerbate ground subsidence or cause damage to infrastructure in New Orleans East.[508]

---

[504] Rice-4 at 20:4-17.
[505] J. Long-3, Exhibit JEL-6.
[506] J. Long-3, Exhibit JEL-6 at 1.
[507] J. Long-3, Exhibit JEL-6 at 1.
[508] Losonsky-1 at 8:12-14.

The C-K Report also concludes that the CT Alternative's proposed groundwater withdrawal rate of 96 gpm is "relatively low" and will not contribute to subsidence in New Orleans East.[509]

An additional report[510], developed and prepared by CB&I Governmental Solutions, Inc., CB&I Report, and submitted into evidence in this proceeding by ENO, also reached the same conclusions as those reached in the C-K Report.[511] Specifically, the CB&I Report concludes that, based on drawdown and settlement calculations and taking known aquifer characteristics into account, the proposed groundwater withdrawals for the CT Alternative and the RICE Alternative will be too small to contribute to any subsidence in the Michoud area.[512] In addition, Dr. Losonsky testified that the analytical methods employed in the addendum to the C-K Report and the CB&I Report are founded on the same hydrogeologic and geotechnical principles.[513] Dr. Losonsky's analysis in this case also supports the findings and conclusions contained in the CB&I Report.[514]

Historically speaking, in 1983, there were approximately 200 wells in the Gonzales-New Orleans aquifer along the Mississippi River from St. Charles to St. Bernard Parishes, roughly half of which had flow rates in the range of 1,000 to 2,000 gpm.[515] Dr. Losonsky has concluded that since a higher flow rate has already been applied to the Gonzales-New Orleans aquifer in the past, the total possible consolidation settlement for the CT Alternative has already occurred, and continuing pumping at the same or lower flow rates (96 gpm) cannot cause additional settlement.[516] According to ENO, the CT Alternative cannot exacerbate subsidence because the

---

[509] J. Long-3, Exhibit JEL-6 at 1.
[510] Losonsky-1, Exhibit GL-3.
[511] Losonsky-1 at 17:19-22.
[512] Losonsky-1 at 17:19-22.
[513] Losonsky-1 at 18:1-6.
[514] Losonsky-1 at 18:15-17.
[515] J. Long-3, Exhibit JEL-6 at11.
[516] J. Long-3, Exhibit JEL-6 at16.

settlement it can create is "very small" and will already have occurred during the past groundwater withdrawal.[517] The impact of the RICE Alternative would be even less. Based on engineering estimates provided by ENO's equipment vendor and contractor, the RICE Alternative will require a reduced pumping rate of 3.9 gpm.[518] The anticipated pumping rate for the RICE Alternative is less than one tenth of the pumping rate for the CT Alternative.[519] According to the Addendum to the C-K Report, when compared to the original CT Alternative proposed flow rate of 96 gpm, the RICE Alternative usage rate will result in a 95% groundwater use reduction.[520] When compared to the deactivated Michoud units, the alternative recommended by the Advisors -- the RICE Alternative -- usage rate will result in a 99.9% groundwater use reduction.[521]

The Joint Intervenors have challenged ENO's positions as they relate to the effects on the infrastructure in New Orleans East that may result from groundwater withdrawal in the event that either the CT Alternative or the RICE Alternative is approved by the Council. One of the vulnerabilities caused by the NOPS facility, according to Joint Intervenors' witness Dr. Alexander Kolker, is the potential for the proposed NOPS to further contribute to subsidence at the NOPS site, in the surrounding community, and potentially in New Orleans' recently upgraded storm risk reduction system.[522] Dr. Kolker cites several studies in support of his position that groundwater withdrawal at Michoud has caused subsidence.[523] The most recent study relied upon by the Joint Intervenors was conducted by several individuals from NASA's Jet Propulsion Laboratory, University of California, and Louisiana State University ("NASA

[517] Losonsky-1 at 16:11-16.
[518] Losonsky-1, Exhibit GL-2 at 2.
[519] Losonsky-1, Exhibit GL-2 at 2.
[520] Losonsky-1, Exhibit GL-2 at 2.
[521] Losonsky-1, Exhibit GL-2 at 2.
[522] Kolker-1 at 2:1-10.
[523] Kolker-1 at 4-5.

Study").[524] The authors of the NASA Study assessed subsidence rates measured with interferometric Synthetic Aperture Radar ("InSAR") images from two radar images from June 16, 2009 and June 2, 2012 from aircraft flying at an altitude of 41,000 feet.[525] The NASA Study determined subsidence rates for much of the greater New Orleans area for the period June 2009 to July 2012 and linked the subsidence near Michoud to groundwater withdrawal.[526]

ENO rejects the interpretation that the NASA Study found a direct cause of subsidence as a result of groundwater withdrawal at the Michoud location. The CB&I Report points out that the authors of the NASA Study noted that a major limitation of their analysis was that only two radar images were used for the InSAR evaluation so that the effects of seasonal and environmental variations prior and between the dates of the radar images could not be evaluated.[527] River levels were also higher in 2009 than in 2012 and there were significant differences in other hydrologic conditions between the two radar images.[528] Also noted in the CB&I Report were the statements made to the media by the lead author of the NASA Study, C. E. Jones, that "additional research is needed to directly link groundwater pumping to the subsidence rates."[529] Jones also stated that it is unclear whether the subsidence results from groundwater withdrawal, compaction of soft soils and other geologic processes, such as the nearby "Michoud fault."[530] Based on the specific analysis conducted by CB&I and the noted limitations and uncertainties in subsidence rates contained in the NASA Study, some of which have been recognized by its lead author, the CB&I Report concludes that the subsidence in the Michoud

---

[524] Kolker-1 at 4-5.
[525] Losonsky-1, Exhibit GL-3 at 17.
[526] Losonsky-1, Exhibit GL-3 at 17.
[527] Losonsky-1, Exhibit t GL-3 at 17.
[528] Losonsky-1, Exhibit GL-3 at 17-18.
[529] Losonsky-1, Exhibit GL-3 at 18.
[530] Losonsky-1, Exhibit GL-3 at 18.

area is related to compaction of near surface soils and peat and to the concentrated loads provided by large industrial structures.[531]

In response to ENO's elevation design for the proposed project, Dr. Kolker asserts that the design of the NOPS plant is quite close to sea level, and will become even closer to sea level (and potentially below sea level) over the coming decades, increasing the vulnerability of this facility to flooding.[532]

The Joint Intervenors are also critical of the analysis, methods and evidence used by the authors of the C-K Report in reaching their conclusions. In Dr. Kolker's view, the data provided in the C-K Report are woefully insufficient to judge subsidence risks.[533] He states that the data included in the report is "highly limited" because the photographs included in the C-K Report captured only one point in time and were two few in number to be informative.[534] The photographs of the buildings also are taken from a distance that is too far for any observer to carefully make any analysis.[535] As a result of these criticisms of the C-K Report, Dr. Kolker recommends that the Council hire an independent engineering or scientific form to investigate whether the NOPS plant will cause subsidence to the facility itself, the surrounding community, or nearby flood protection structures.[536]

The Advisors agree with ENO that the groundwater withdrawal associated with either the proposed CT Alternative or the proposed RICE Alternative will not exacerbate subsidence or cause damage to infrastructure in New Orleans East. ENO presented expert testimony that is well supported by two detailed studies containing site-specific analysis and calculations that also

[531] Losonsky-1 at GL-3 at 18.
[532] Kolker-1 at 2:11-13.
[533] Kolker-1 at 6:16-17.
[534] Kolker-1 at 6:6-16.
[535] Kolker-1 at 6:13-15.
[536] Kolker-1 at 6:17-20.

provided historical comparisons to past groundwater usage. The significantly decreased expected pumping rates for the CT Alternative reduce the potential for any additional subsidence that may be attributable to groundwater withdrawal. The drawdown calculations for the CT Alternative predict a considerably reduced maximum drawdown with the new and efficient technology of the proposed CT Alternative. As also discussed above, it is noteworthy that these calculations were performed using the most conservative assumption that the CT Alternative will operate 24 hours a day, 365 days a year. The Advisors are persuaded by the evidence presented by ENO that the risk of subsidence resulting from groundwater withdrawal is *de minimis* considering the expected pumping rate for the RICE Alternative is less than one tenth of the pumping rate for the CT Alternative. The Advisors also find it compelling that ENO's evidence demonstrates that when compared to the deactivated Michoud units, the RICE Alternative usage rate will result in a 99% groundwater use reduction. Like the CT Alternative analysis, it is noteworthy that the drawdown calculations were performed using the most conservative assumption that the RICE Alternative will operate 24 hours a day, 365 days a year.

The Advisors are not persuaded by the testimony set forth by the Joint Intervenors' witness, Dr. Kolker. In his pre-filed written testimony submitted in this proceeding, Dr. Kolker provides a general discussion regarding topics such as groundwater withdrawal and subsidence but did not provide any analysis containing his own calculations or site specific information to support his positions. He merely relied on the research of others, which did not include site specific analysis or drawdown calculations, including the NASA Study despite its admitted limitations and uncertainties. Dr. Kolker also criticized the work of ENO's expert, Dr. Losonsky, which provided the best evidence in the record on the issue of subsidence for the proposed project. Dr. Kolker also acknowledged his inexperience in performing these types of detailed groundwater calculations and subsidence analysis. In the hearing on the merits of this case, Dr. Kolker testified that, prior to this case, he had never attempted to assess possible subsidence resulting from groundwater withdrawal from a specifically proposed industrial facility.[537]

Although, for reasons detailed in their expert testimony in this case, the Advisors do not believe the CT Alternative is in the public interest. However, that conclusion was not, in any respect, based on concerns regarding the subsidence and emissions issues raised in this proceeding. As detailed above, the Advisors do conclude that the RICE Alternative is in the public interest and should be approved for several reasons, including the significant anticipated reduction in groundwater use and air emissions associated with the new units. Further, the Advisors conclude that given that the risk of subsidence resulting from groundwater withdrawal by the RICE Alternative is *de minimus*, the selection of Michoud as a site for that plant is reasonable.

ENO witness, Losonsky, has also submitted testimony that addresses concerns regarding flood risks at the Michoud site. The Southeast Louisiana Flood Protection Authority - East ("SLFPA-E") was created in response to Hurricane Katrina and its purpose is to improve flood protection in New Orleans and other surrounding areas, including flooding from hurricanes, rain, or other storm surges.[538] The primary goal of SLFPA-E was upgrading and maintaining the Hurricane and Storm Damage Risk Reduction System ("HSDRRS").[539] The HSDRRS includes a series of levees, storm surge barriers and upgrades to pumping capacity that have significantly increased the defense against storm surge in New Orleans East, including at the proposed NOPS site.[540] As a result of these improvements, the Coastal Protection and Restoration Authority

---

[537] Hr'g Tr. 12/20/17, 140:3-8.
[538] Losonsky-1 at 23:6-10.
[539] Losonsky-1 at 23:6-10.
[540] Losonsky-1 at 25:1-4.

("CPRA") predicts no flooding in the area that includes the proposed NOPS site in its 2017 Master Plan.[541] More significantly, the flood protection measures that have been installed eliminate estimated flooding at the Michoud location even under the worst case scenario considered under the 2017 Master Plan.[542]

In addition to the flood protection measures undertaken by the SLFPA-E discussed above, ENO has, in an effort to further protect against flooding, determined the appropriate Top of Concrete ("TOC") level for the site to be 3.5 feet above sea level, which is 2.5 feet higher than the FEMA Advisory recommendation.[543] The TOC level is also 1 foot higher than the observed Hurricane Katrina flooding and thus Dr. Losonsky believes that the planned elevation of the NOPS site is sufficient to protect against flood risks.[544]

The Joint intervenors make two arguments regarding the potential for an increased risk of flooding at the Michoud site. First, Dr. Kolker argues that subsidence in the Michoud area is linked to groundwater withdrawal;[545] and as a result of that subsidence increased risk of flooding occurs.[546] Second, Dr. Kolker relies on the CPRA's 2012 Master Plan and asserts that the area near NOPS "is likely to see flood depths of 10-15 feet at some point over the next fifty years."[547] However, as Dr. Losonsky pointed out, the HSDRRS includes a series of levees and storm surge barriers and upgrades to pumping capacity.[548] The 2017 Master Plan, relied upon by ENO acknowledges that these upgrades have significantly increased the defense against storm surge in New Orleans East, including the NOPS site.[549] As a result, the 2017 Master Plan predicts no

[541] Losonsky-1 at 25:4-9.
[542] Losonsky-1 at 25:5-9.
[543] Losonsky-1 at 24:4-9.
[544] Losonsky-1 at 27:10-14.
[545] Kolker-1 at 4:11-16.
[546] Kolker-1 at 2:17-20.
[547] Kolker-1 at 7-9.
[548] Losonsky-1 at 25:1-2.
[549] Losonsky-1 at 25:4-9.

flooding at the proposed NOPS site under the worst case scenario considered under the Master Plan.[550] The Advisors note that this is a significant change compared to the 2012 Master Plan. The Advisors also agree with Dr. Losonsky that there is sufficient evidence in the record demonstrating that considerable flood protection measures have been taken by SLFPA-E to mitigate the risk of flooding at the Michoud site. ENO's design plan and proposed elevation for the project adequately considers the potential for future flooding and thus, the Advisors conclude that the flood risks at the Michoud site have been reasonably mitigated.

C. There Is No Evidence In The Record That Siting a Project at Michoud Will Perpetuate Racial Injustice or that the Proposal Is Racially Motivated

Joint Intervenors' witness Wright recommends that the City Council deny the application by ENO for the proposed NOPS because it would have a racially discriminatory effect on predominantly African American and Vietnamese American residents living in New Orleans East.[551] Dr. Wright argues that ENO's proposal will have a racially discriminatory effect for the following reasons: (1) ENO established a deeply flawed planning process without notice to or input from residents of New Orleans East; (2) ENO evaluated sites in complete disregard to population growth; (3) ENO applied for and/or obtained environmental permits that do not require public notice, public comments, or public hearing.[552] However, Dr. Wright has no background, education, or experience in energy resource planning or power plant siting or permitting -- Dr. Wright's degrees and the majority of her professional experience, while impressive, all appear to be in the field of Sociology and/or racial discrimination.[553] She does not appear to have any relevant experience in utility resource planning, utility transmission or

[550] Losonsky-1 at 25:5-9.
[551] Wright-1 at 22:16-19.
[552] Wright-1 at 21:4-22:12.
[553] Wright-1, Exhibit 1.

generation planning or operations, or electrical engineering that would assist her in evaluating and understanding the decision to put a power plant in a specific location.[554] Dr. Wright and the other Joint Intervenor witnesses have simply failed to provide sufficient evidence to demonstrate that the siting of a natural gas-fired power plant at the Michoud site will perpetuate environmental racism.

ENO has presented as a witness Bliss Higgins, an experienced former Assistant Secretary of the LDEQ's Office of Environmental Services and recognized air quality expert,[555] who over the course of her work at LDEQ and later as an environmental consultant, has studied the EPA's guidelines on environmental justice, and conducted evaluations to assess whether particular projects would result in a disproportionate adverse impact on minority or low-income populations.[556] Higgins testified that, based on the specific facts and circumstances of the proposed NOPS alternatives, the applicable science, and well-established environmental standards, it is her opinion that the operation of NOPS will not result in any potential environmental injustice for the following reasons.[557]

Higgins testifies that environmental justice is generally a consideration of whether minority and low-income populations are being disproportionately exposed to adverse environmental effects.[558] Although no definition of environmental justice enjoys universal acceptance, Higgins explains, the following definition from the EPA is widely cited: "Environmental justice is the fair treatment and meaningful involvement of all people regardless

---

[554] Wright-1, Exhibit 1.
[555] Higgins-1 at 6:4-9:3.
[556] ENO-2 at 10:10-13.
[557] ENO-2 at 17:3-5.
[558] ENO-2 at 8:6-9-2, *citing* Learn About Environmental Justice, United States Environmental Protection Agency, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.

of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies."[559] She states that the EPA further defines "fair treatment" as meaning that "no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies." Further, 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."[560] Higgins notes that the LDEQ relies on EPA guidance in evaluating environmental justice concerns.[561]

Higgins finds no cause for concern that minority or low-income populations would be disproportionately exposed to adverse health impacts.[562] First, Higgins states, Orleans Parish is currently in attainment with all NAAQS.[563] Further, she notes, the project will be sited more than a mile from the nearest residential area.[564] In addition, the objective data support the conclusion that no significant adverse health impacts would result from the NOPS.[565] In short, the EPA and LDEQ have set regulatory standards for air emissions in order to protect human health. If those standards are met, the Council should rely upon the EPA and LDEQ's determinations that there will be no adverse health impact. If there is no significant adverse

[559] ENO-2 at 8:6-9-2, *citing* Learn About Environmental Justice, United States Environmental Protection Agency, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.
[560] ENO-2 at 8:6-9-2, *citing* Learn About Environmental Justice, United States Environmental Protection Agency, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.
[561] ENO-2 at 9:7-9.
[562] ENO-2 at 17:9-10.
[563] ENO-2 at 17:5-6.
[564] ENO-2 at 17:6-7.
[565] ENO-2 at 17:7-9.

health impact, then there can be not racially disproportionate significant adverse health impact. Furthermore, ENO witness Rice commits that the air emissions from NOPS will not exceed regulatory standards that have been put in place to safeguard human health and the environment and will be less than the retired Michoud units.[566] The Joint Intervenors have failed (1) to offer any evidence that effectively counters ENO's evidence that the proposed plant will meet all applicable regulatory requirements regarding emissions and (2) to demonstrate that there will be any significant adverse health impacts from siting the plant at Michoud. To the extent that there is no racially disproportionate impact, the Council's inquiry as to racial environmental discrimination could end here. However, the Advisors will also address certain case law and Dr. Wright's additional claims in order to provide the Council with as thorough an examination of the evidence in this case as possible.

First, the Advisors note that Louisiana case law regarding environmental justice does not support a finding that environmental discrimination would be perpetuated by the siting of a natural gas plant at Michoud. The case of *North Baton Rouge Environmental Association v. Louisiana Department of Environmental Quality* is particularly instructive. In that case, before the Court of Appeal of Louisiana, First Circuit, plaintiff environmental groups sought judicial review of a grant of a plant construction permit by the LDEQ.[567] In that case, the LDEQ had granted a permit to Exxon Chemical Americas ("Exxon") for the construction of a new polypropylene plant adjacent to its existing facility in East Baton Rouge Parish.[568] The area in which the plant was to be located had been designated a part of a five-parish non-attainment area for ozone pollution, which signifies that the area had failed to meet the NAAQS for specific

---

[566] Rice-4 at 21:10-15.

[567] *N. Baton Rouge Envtl. Ass'n v. La. Dep't of Envtl. Quality*, 805 So. 2d 255 (La. App. 1 Cir. 2001).

[568] *N. Baton Rouge Envtl. Ass'n v. La. Dep't of Envtl. Quality*, 805 So. 2d 255, 257.

pollutants, and facilities in the area had undertaken mandatory and voluntary changes aimed at reducing the ozone related to industrial facilities.[569] Environmental groups appealed the grant of the permit, and one of the assignments of error that they argued was that the LDEQ had failed to respond to their charge that the permitting of the facility was tantamount to environmental racism.[570]

> Comments received by the DEQ had included that charge that Alsen, the town near to which the plant was cited, "is probably one of the best examples of environmental racism in the nation. The problem here goes far beyond mere environmental justice concerns. It is a case of outright discrimination. . . . Alsen has been forced to continue to endure the racist actions of the past. The decision to industrialize Alsen was not made by the people of Alsen. In fact, because of their race, the people of Alsen were deliberately and systematically denied the right to participate in government and shape their own destinies. Now, Alsen is told it must live with these racist decisions."[571] Exxon replied to this charge by letter, citing a history of voluntary emissions reductions and stating that it did not feel the allegations of racial discrimination were valid.[572]

The district court reviewed the evidence and in its reasons for upholding the grant of the permit, stated:

> The environmental justice review issue. It is unfortunate that the original zoning placed this industrial complex next to [the community of] Alsen. The fact that it was done a long time ago, doesn't make any difference in considering environmental justice because a lot of things were done a long time ago that were not right. . . . Placing this industrial area in the neighborhood of the Alsen community does not appear to be intentionally racist. It's between a railroad and a river in a relatively rural area. Exxon has used plant facility that was already in existence. They're actually putting out less pollution than the plant that was there previously. Considering the other policy considerations, should Exxon locate

[569] *N. Baton Rouge Envtl. Ass'n v. La. Dep't of Envtl. Quality*, 805 So. 2d 255, 257.
[570] *N. Baton Rouge Envtl. Ass'n v. La. Dep't of Envtl. Quality*, 805 So. 2d 255, 262.
[571] *N. Baton Rouge Envtl. Ass'n v. La. Dep't of Envtl. Quality*, 805 So. 2d 255, 262.
[572] *N. Baton Rouge Envtl. Ass'n v. La. Dep't of Envtl. Quality*, 805 So. 2d 255, 262-3.

> this some place where there is an area where there is no pollution? That's not a particularly good idea. Should they locate it in another industrial area? Well, that only moves the problem to somebody else's city. Overall, in the balance, I cannot find that DEQ abused its discretion in putting [the Exxon plant] in an industrial area at the site of a prior plant that actually probably produced more pollution than the system that's been proposed.[573]

In rendering its review of that decision on appeal, the First Circuit Louisiana Court of Appeal stated:

> Upon review of the record, we cannot say that DEQ failed to respond to the charges leveled [by the appellants]. The Exxon facility at issue is situated in an industrially zoned area adjacent to a state highway, a railroad, and the Mississippi river. We conclude, as did the district court, that it is unfortunate that the Alsen community is also situated in this general area; however, this fact alone does not constitute environmental racism.[574]

Thus, the court found that in a situation where a plant was being built at the site of a plant that was there previously, that had polluted more, in an industrial area where there was no indication that the original zoning was intentionally racist, the granting of a permit did not constitute environmental racism solely due to the proximity of an African American neighborhood. The Advisors believe that there are factors in this case compares favorably to that case. In this case, there is already less air pollution in the Orleans Parish, as is evidenced by the fact that Orleans Paris is in attainment with all NAAQS,[575] whereas the Alsen area was not. As ENO witness Charles Rice testifies, the Michoud site is a sparsely populated industrial area where ENO operated a power plant for decades.[576] In addition, based on expert testimony provided by ENO, the proposed RICE units will represent a significant reduction in allowable

[573] *N. Baton Rouge Envtl. Ass'n v. La. Dep't of Envtl. Quality*, 805 So. 2d 255, 263.
[574] *N. Baton Rouge Envtl. Ass'n v. La. Dep't of Envtl. Quality*, 805 So. 2d 255, 263.
[575] ENO-2 at 17:5-6.
[576] Rice-4 at 21:10-15.

emissions compared to the allowable emissions from the deactivated Michoud units.[577] Also, those emissions from the RICE units are dissipated before they reach the fence line to concentrations well below the limits for public breathing level air based on federal air quality standards.[578] Based on the emissions allowed under ENO's current Michoud permit, the proposed RICE unit emissions represent an average 77.3% reduction in criteria pollutants pursuant to the EPA's air quality standards compared to the two old Michoud units retired in 2016.[579] Further, while the appellants in the Alsen case argued that the initial siting of the facility was racial discrimination against the community of Alsen, no such argument has been made in this case. In fact, in her testimony, Dr. Wright testifies that that when the initial construction of the Paterson and Michoud plants was undertaken, New Orleans East was largely undeveloped wetlands and sparsely populated.[580] Thus, there is no evidence in the record that indicates that the initial siting of the Michoud plants were the result of racial discrimination, therefore there was no environmental racism relative to the siting of Michoud that continued use of that site for a power plant could "perpetuate."

As to the remainder of Dr. Wright's claims, namely that (1) ENO established a deeply flawed planning process without notice to or input from residents of New Orleans East; (2) ENO evaluated sites in complete disregard to population growth; (3) ENO applied for and/or obtained environmental permits that do not require public notice, public comments, or public hearing, these arguments simply fall apart under further examination. Dr. Wright claims that decisions and circumstances leading up to and including ENO's first application for City Council approval of the proposed power plant follow the pattern of systemic environmental racism that

---

[577] Higgins-2 at 15:6-8.
[578] Higgins-1 at 50:1-7, 11-15.
[579] Higgins-1 at 18:3-6.
[580] Wright-1 at 13:7-14:8.

disproportionately burdens communities of color with toxic industrial pollution and hazards.[581] She argues that there was a woefully inadequate process for public input that excluded the participation of people who would be most impacted by the proposed power plant.[582] She also argues that the steps ENO took leading up to and including the application for the proposed gas power plant do not comport with environmental justice.[583]

Dr. Wright catalogs what she believes to be several flaws with the Council's IRP that she believes allowed ENO to exclude the public from its planning process and were a clear departure from public participation and that she believes that these flaws carry forward into this proceeding considering ENO's application to build NOPS.[584] Dr. Wright argues that because the siting of the proposed gas power plant is not mentioned in ENO's IRP there was no public input on Entergy's siting decision.[585] Dr. Wright further argues that the fact that there was no public meeting regarding the IRP in New Orleans East, where NOPS is proposed was a form of environmental injustice.[586] In making this argument, Dr. Wright appears to completely misunderstand the nature of the IRP process, however. The siting of a proposed power plant was not discussed in the IRP proceeding because the location of a proposed power plant is not an appropriate matter to be considered in an IRP proceeding. An IRP proceeding is meant to identify what resource needs the utility has and conduct an economic analysis of what type of resource is likely to be the most economically beneficial in meeting the identified resource need. An IRP does not consider specific projects, rather it identifies need and gives the utility a general direction to explore in meeting that need. An IRP proceeding simply does not consider the

[581] Wright-2 at 2:6-9.
[582] Wright-2 at 2:16-20.
[583] Wright-1 at 4:18-19.
[584] Wright-1 at 5:1-10:8.
[585] Wright-1 at 12:7-9.
[586] Wright-1 at 5:1-12.

location of any specific resource that may be acquired in the future. The location of specific projects is considered in a process such as the instant docket, begun by the Council once ENO has filed its Application before the Council, and which has provided ample opportunity for public input.

The Company's 2015 IRP process and its specific proposal to construct NOPS have provided multiple opportunities for meaningful public participation.[587] ENO CEO Charles Rice testified that ENO has held at least 21 public meetings regarding NOPS, and he personally attended most of those meetings.[588] The Council has also taken several concrete steps to ensure transparency and public input on whether NOPS should move forward.[589] Council Resolution Nos. R-16-506 and R-17-426 have 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.[590] ENO's resource planning process that identified the need for NOPS proceeded under guidelines set by the Council itself, and the Council has recognized the potential importance of constructing new generation in Orleans Parish (Resolution No. R-15-524).[591] There were multiple opportunities for public participation in the planning process, and ENO has continued its dialog with stakeholders on the plans for NOPS.[592]

This proceeding has not been rushed, and the need for generation capacity in New Orleans did not arise suddenly. Any member of the public who took the time to follow the

[587] Rice-4 at 17:10-20
[588] Rice-4 at 17:10-20
[589] Rice-4 at 18:1-7.
[590] Rice-4 at 18:1-7.
[591] Rice-4 at 21:5-9.
[592] Rice-4 at 21:5-9.

Council's energy-related proceedings would have been aware that although the type of technology and specific location were not determined until ENO filed its application in this docket, the potential siting of a power plant in New Orleans has been under discussion before the Council since at least 2015. The Council has expressed concern regarding ENO's ability to continue to provide reliable service to New Orleans ratepayers at a reasonable cost since the termination of the Entergy System Agreement was proposed.

Entergy Services, Inc., ("ESI") filed on behalf of certain Entergy Corporation Operating Companies ("OpCos") an application at FERC to shorten the System Agreement termination provision so that the System Agreement could be terminated more quickly.[593] Out of concern that ENO, which received significant benefits under the System Agreement in terms of access to capacity and energy from its sister OpCos, would be disadvantaged by the early termination of the System Agreement, the Council directed the Advisors to intervene in the FERC proceeding on its behalf and on November 21, 2013, after proper notification, the Council adopted Resolution No. R-13-432 establishing Docket No. UD-13-03 to investigate the prudence and reasonableness of ENO's support for shortening the System Agreement termination notice provision and any resulting impact on New Orleans ratepayers. Also on November 21, 2013, the Council adopted Resolution No. R-13-433 after being properly noticed, which established Docket No. UD-13-04 to consider issues related to the prudence of ENO's support of a Louisiana-wide Transmission Pricing Zone ("TPZ") within MISO and the resulting impact that a Louisiana-wide TPZ would have on New Orleans ratepayers.

[593] Entergy Services, Inc., Amendment to Section 1.01 of the Entergy System Agreement, Docket Nos. ER14-75, *et al.* (Oct. 11, 2013).

After an intervention period, which allowed any interested parties to intervene in its public proceeding regarding the proposal to terminate the System Agreement early, FERC set the proceeding for settlement discussions facilitated by a FERC ALJ.[594] Along with the other parties to the case, the Advisors negotiated with ENO on behalf of the Council and a settlement between all parties to the case was ultimately reached, which, on August 14, 2015, ESI filed the Settlement Agreement in the public proceeding at FERC.[595] The Settlement Agreement was subject to review and approval of the Council as well as the other regulatory commissions party to the Settlement Agreement. Thereafter, on August 27, 2015, ENO filed a "Notice of Settlement in FERC Docket ER14-75" in both Council Docket Nos. UD-13-03 and UD-13-04 so that the Council would be able to publicly consider whether the proposed Settlement Agreement was in the public interest.

The Settlement Agreement the Council put out for public comment, and which was at this point a publicly available document both through FERC's website and through the Council, included the following language:

> ENO will use reasonable diligent efforts to pursue the development of at least 120 MW of new-build peaking generation capacity within the City of New Orleans. As part of this commitment, ENO will fully evaluate Michoud or Paterson, along with any other appropriate sites in the City of New Orleans, as the potential site for a combustion turbine ("CT") or other peaking unit to be owned by ENO, or by a third party with an agreed-to PPA to ENO. This evaluation will take into consideration, among other material considerations, the results of the Michoud site analysis that was

[594] *Entergy Services, Inc.*, Combined Notice of Filing #2, Docket Nos. ER14-75-000, *et al*. (Oct 15, 2013). *Entergy Services, Inc.* Order Conditionally Accepting Notices of Cancellation and Accepting and Suspending Proposed Amendment, Establishing Hearing and Settlement Judge Procedures, and Consolidating Proceedings, 149 FERC ¶ 61,262 (2014).

[595] Settlement Agreement of Entergy Services, Docket Nos. ER14-75 *et al*. (Aug. 14, 2015) ("Settlement Agreement").

> completed in connection with the Summer 2014 Request for Proposal; and
>
> ENO commits to use diligent efforts to have at least one future generation facility located in the City of New Orleans; ….
>
> The commitments set forth in this Section II.E are subject to mutually satisfactory resolution of all material considerations, including, without limitation: (a) financial feasibility for ENO; (b) affordability for ENO customers; (c) economic feasibility in comparison to other potential projects, locations, or alternatives; (d) timely rate recovery; (e) regulatory jurisdiction over such facility(ies) to the extent not owned by ENO; and (f) consistency with sound utility practice and planning principles.[596]

Thus, the Settlement Agreement, as part of a settlement addressing many different issues related to the early termination of the System Agreement and the measures needed to protect New Orleans from the negative impacts of losing that agreement, directed ENO to explore the possibility of locating at least one future generation facility in New Orleans, subject to the resolution of various associated issues the Council would need to review prior to approval of any specific project. It is important to note that while this language clearly directed ENO to begin exploring the option of locating generation in New Orleans, nowhere was it promised that the Council would approve any specific generator.

In order to assure a full public process in accordance with Council procedures in addition to the public process occurring at FERC, the Council, on September 3, 2015, adopted Resolution No. R-15-437, which stated that it was "the Council's desire that all parties affected by the Settlement Agreement be provided an opportunity to understand the proposal, submit comments and have their views considered prior to the Council's final consideration of the Settlement Agreement." All interested parties therefore had the opportunity to intervene and submit comments regarding the Settlement Agreement (in addition to their prior opportunity to

[596] Settlement Agreement at 13-14.

participate in the FERC proceeding). After receiving no opposition from any party or the public at large, on November 5, 2015, after proper notice, the Council adopted Resolution No. R-15-524, which approved the FERC Settlement Agreement as being just, reasonable and in the public interest. In describing the Settlement Agreement being approved by the Council, Resolution No. R-15-524 stated:

> **WHEREAS**, ENO will use reasonable diligent efforts to pursue the development of at least 120 MW of new-build peaking generation capacity within the City of New Orleans. As part of this commitment, ENO will fully evaluate Michoud or Paterson, along with any other appropriate sites in the City of New Orleans, as the potential site for a combustion turbine ("CT") or other peaking unit to be owned by ENO, or by a third party with an agreed-to PPA to ENO. This evaluation will take into consideration, among other material considerations, the results of the Michoud site analysis that was completed in connection with the Summer 2014 Request for Proposal; and
>
> **WHEREAS**, ENO commits to use diligent efforts to have at least one future generation facility located in the City of New Orleans; and…[597]

Thus, since at least November of 2015, the public had notice that ENO had been directed to pursue peaking generation within the City, and that one of many possible outcomes could be a proposal to build a CT or other peaking unit at least 120 MW in size at the Michoud site. The Resolution was made available to the public in the Council's usual manner and was discussed at a Council UCTTC meeting, which was recorded on video, broadcast and made available over the Council's website.[598]

Further, the concept of adding peaking capacity to ENO's portfolio was discussed extensively in ENO's 2015 IRP process. That IRP process was also open to the public to

---

[597] Resolution No. R-15-524 at 12.

[598] Videos of Council meetings are available in the Council's on-line archives. http://www.nolacitycouncil.com/video/video_legislative.asp.

intervene and participate formally as a party, or simply to attend multiple technical conferences to hear about the IRP and ask questions.[599] The preferred portfolio selected by ENO in its 2015 IRP process was a 250 MW CT unit, however, by the time the Council's final order regarding the IRP was issued, ENO's Initial Application had already been filed, and so in order not to pre-judge the Instant Application, in Resolution No. R-17-100 the Council ordered that:

> 2. All issues related to ENO's NOPS CT proposal should be fully vetted in Council Docket No. UD-16-02 including, but not limited to the need for a CT, size, timing, environmental concerns, social justice, cost, transmission, and reliability considerations. **ACCEPTANCE OF THIS IRP SHALL HAVE NO PRECEDENTIAL EFFECT WITH RESPECT TO THE COUNCIL'S EVALUATION OF ENO'S NOPS CT APPLICATION IN COUNCIL DOCKET UD-16-02.**[600]

As is discussed above, over the Course of this proceeding, ENO's proposal for a 226 MW CT unit at Michoud, which is consistent with ENO's preferred portfolio developed in the IRP process has since evolved due to revisions to the load forecast that reduced the projected load, leading ENO to also proposed the RICE Alternative based on updated information received since the conclusion of the 2015 IRP process. Thus, members of the public and parties who follow the Council's energy matters have had notice that the Company may be considering new generation in the City since 2015, and the Initial Application has been before the Council since June of 2016, and interested members of the public have had multiple opportunities to make their views regarding that issue known to the Council in the proceeding considering the System Agreement termination Settlement Agreement, the 2015 IRP proceeding and the instant docket.[601]

---

[599] Resolution No. R-17-100 at 5-8.

[600] Resolution No. R-17-100 at 94.

[601] Certain parties have raised arguments in this docket that the Advisors' roles as a party representing the Council's interest in regulatory utility proceedings and also providing assistance to the Council in the decision-making process violates their right to due process. This issue has long been settled by the Louisiana and federal

Dr. Wright's second argument also fails. Dr. Wright argues that ENO did not conduct a professional site selection for NOPS, to do so, ENO would have to consider additional criteria for evaluating sites, both potential opportunities and the risks and adverse impacts of a site, in particular a site in close geographic proximity to residential neighborhoods.[602] She argues that when the initial construction of the Paterson and Michoud plants was undertaken, New Orleans East was largely undeveloped wetlands and sparsely populated.[603] The population has grown significantly over the decades, residential and non-industrial land uses have expanded and are now within one mile of the Paterson and Michoud sites.[604] New Orleans East is now approximately 19% of the city's population (as opposed to 1% in 1947) and is 84% African American and 8% Asian American.[605]

---

courts. The Louisiana Fourth Circuit, addressing this exact issue wrote: "The law, both federal and state, is that a 'separation of functions' is required in adjudicative proceedings, but not in legislative proceedings. The federal Administrative Procedure Act requires separation of functions in adjudicative proceedings, but explicitly exempts 'proceedings involving the validity or application of rates, facilities, or practices of public utilities.' Federal case law has established that separation of functions is not required in ratemaking proceedings on either statutory or constitutional due process grounds. The U.S. Supreme Court has stated that under federal and state case law, the combination of investigative and judging functions is not a denial of due process. In Louisiana, the state Administrative Procedure Act distinguishes between judicial proceedings, in which separation of functions is required, and rulemaking proceedings, in which it is not." (Citations Omitted) *See Alliance for Affordable Energy, Inc. v. Council of City of New Orleans*, 578 So. 2d 949, 968 (La. Ct. App.4th Cir.), (emphasis added), writ granted sub nom. *Alliance for Affordable Energy, Inc. v. The Council of the City of New Orleans*, 585 So. 2d 554 (La. 1991), writ granted, 585 So. 2d 555 (La. 1991), and vacated sub nom. *Alliance for Affordable Energy v. Council of City of New Orleans*, 588 So. 2d 89 (La. 1991). Decision vacated for reasons other than the proposition of law cited herein. Moreover, in *Gulf States Utilities Co. v. Louisiana Public Service Commission*, the Louisiana Supreme Court rejected Gulf States' contention that it was denied due process on the basis that the Commission's majority opinion was authored by the Commission's consultants and counsel who had acted as the company's adversaries during the hearings. The Court noted that the Commission is statutorily permitted to retain special counsel, engineers, consultants, etc. to assist its economics and rate analysis division in "evaluating, reviewing, and representing the commission in matters affecting services and rates charged by public utilities to Louisiana consumers or the judicial review thereof." *See* La. Rev. Stat. Ann. §. 45:1163.3; *Gulf States Utils Co. v. Louisiana Pub. Serv. Comm'n*, 578 So. 2d 71, 82 (La. 1991) Like the LPSC, the Council has the same authority to retain legal counsel, engineers, and consultants to assist with utility matters. *See*, Home Rule Charter of the City of New Orleans, Article III, Section 3-130. The Administrative Procedure Act is also consistent with the jurisprudence on this issue. The Act specifically exempts proceedings involving rates of public utilities from the separation of functions requirement imposed on adjudicatory proceedings. *See*, 5 U.S.C. § 554(d).

[602] Wright-1 at 12:10-13:6.

[603] Wright-1 at 13:7-14:8.

[604] Wright-1 at 13:7-14:8.

[605] Wright-1 at 13:7-14:8.

Higgins argues, however, that Dr. Wright is mistaken that NOPS would be in close proximity to nearby residential neighborhoods.[606] Higgins states that Wright's Exhibit 6, which Dr. Wright claims shows a distance of less than 4,000 feet/0.75 mile between the proposed NOPS and nearby residential neighborhoods does not identify any residential neighborhoods within that distance.[607] She also states that Dr. Wright appears to have used Google Maps to generate her Exhibit 6, but that EPA has a tool called EJSCREEN that allows users to look at census data within specified distances of a proposed project site.[608] Using that tool she located the Michoud property on the map and reviewed the 2010 census data within one mile of the property, and that the census data indicate that no people live within a one mile radius of the center of the site.[609] Higgins states that the Michoud site is located in a sparsely populated census tract that does not have the "close geographic proximity to residential neighborhoods" that Dr. Wright suggests in her testimony.[610]

Higgins also notes that while Wright argues that according to the 2010 U.S. Census Bureau data, New Orleans East has a total population of 64,310, which is 84% African American and 8% Asian American, and has 22,808 occupied homes,[611] the Michoud site is in Census Tract 17.51, and, according to the 2010 census data, that tract has a population of 836, made up of 62% African American and 4% Asian American, and has a total of 341 occupied homes.[612] Thus, Higgins concludes, the Michoud census tract actually has a lower percentage of African American and Asian American residents than New Orleans East as a whole, and is closer to the

[606] ENO-2 at 10:18-11:9.
[607] ENO-2 at 10:18-11:9.
[608] ENO-2 at 10:18-11:9.
[609] ENO-2 at 10:18-11:9.
[610] ENO-2 at 11:10-16.
[611] ENO-2 at 11, n. 17.
[612] ENO-2 at 11, n. 17.

demographic profile of the City of New Orleans as a whole.[613] Rice also argues that Wright gives an incorrect impression of the population that resides within a mile of the Michoud site.[614]

Higgins further disputes Dr. Wright's allegation that ENO has not considered potential adverse impacts of NOPS are inconsistent with the information and analysis that ENO has provided in support of its application.[615] In particular, she notes, ENO has provided evaluations of the effects NOPS would have in the areas of air quality, public health, and groundwater withdrawal, including providing the C-K Report.[616] She concludes that these evaluations show not only that ENO has considered potential adverse impacts on health and the environment, but also that NOPS will not have such adverse impacts.[617]

Having reviewed all evidence in this case, including the C-K Report, the Advisors are satisfied that ENO has evaluated the Michoud site's advantages and risks sufficiently for the Council to render a decision at this time.

The Advisors also find no merit to Dr. Wright's argument that ENO's process perpetuated environmental racism because it applied for and/or obtained environmental permits that do not require public notice, public comments, or public hearing. To the extent that ENO applied for environmental permits in a manner that meets the requirements of the EPA and LDEQ, the Advisors see no reason for the Council to conclude that applying for such permits reflects discriminatory intent on the part of ENO. To the extent that Dr. Wright does not feel that the EPA and LDEQ processes permit sufficient public input, she should raise that matter before

[613] ENO-2 at 11, n. 17.
[614] Rice-4 at 21:10-15.
[615] ENO-2 12 at 5-16.
[616] ENO-2 12 at 5-16.
[617] ENO-2 at 13:1-3.

the EPA and LDEQ. ENO witness Higgins also disputes Dr. Wright's claim that ENO applied for and/or obtained environmental permits that do not require public notice, public comments, or public hearing, and finds that many opportunities for meaningful involvement by all people have been provided.[618] For example, she states, the Council, LDEQ and other regulatory agencies have all implemented substantive public participation procedures to allow for input by all interested parties on the NOPS.[619] Also, she states that ENO has gone well beyond these required public participation procedures by holding numerous community-based meetings around the ENO service area to inform the public about the proposed NOPS and to receive and respond to public questions and concerns.[620] Higgins thus finds no concern that anyone has been denied an opportunity for meaningful involvement in the decision-making process.[621] Rice also asserts that Dr. Wright has not shown that ENO's applications for certain environmental permits were improper, particularly in light of the prior use of the Michoud site.[622] Moreover, he attests, LDEQ has actually implemented opportunities for public participation in its review of ENO's application, and its proceedings are ongoing.[623]

The Advisors conclude that siting a power plant at Michoud under the circumstances described by ENO in its Initial Application, Supplemental Application, and testimony is reasonable and in the public interest, particularly in light of ENO's commitment to comply with all applicable local, state, and federal laws and regulations. The Advisors recommend that the Council require ENO to submit proof of such compliance in the form of submitting to the Council copies of all permits and authorizations received by the Company.

---

[618] ENO-2 at 17:10-19.
[619] ENO-2 at 17:10-19.
[620] ENO-2 at 17:10-19.
[621] ENO-2 at 17:10-19.
[622] Rice-4 at 16-21.
[623] Rice-4 at 16-21.

IV. <u>WHETHER ENO'S PROPOSED COSTS, COST RECOVERY MECHANISM, AND MONITORING PLAN ARE JUST AND REASONABLE AND SHOULD BE APPROVED BY THE COUNCIL</u>: The estimate of costs is reasonable, but the proposed cost recovery mechanism and monitoring plan are not and a different cost recovery mechanism and modified monitoring plan are required.

ENO's estimate of costs is reasonable, but the proposed cost recovery rider and monitoring plan are not. A different cost recovery mechanism and modified monitoring plan are required.

A. <u>Cost recovery mechanism</u>

ENO has requested approval of a contemporaneous exact cost recovery rider, to begin on the day that NOPS begins commercial operation, to recover non-fuel and capacity costs. The rider they propose would be similar to the Purchased Power Capacity Acquisition Cost Recovery ("PPCACR") rider that has been used to recover costs associated with the Union Power Block 1 ("UPS") acquisition and the Ninemile 6 PPA. The PPCACR would be an interim measure until the next full rate case or an annual Formula Rate Plan ("FRP") review. ENO has also requested that major maintenance costs associated with the project be recovered through a fuel surcharge.

ENO assumes that the 2018 Combined Rate Case will be completed before NOPS begins commercial operation, and therefore the project costs would not normally be reflected in base rates at that time. For this reason, ENO asserts that an exact cost recovery rider applicable to all customers is needed, beginning on the date NOPS commences commercial operation, including a return on equity ("ROE") to be determined in the Combined Rate Case and based on ENO's actual capital structure at the commercial operation date ("COD"). ENO also assumes that an FRP will be approved to commence in 2020 subsequent to the Combined Rate Case. ENO anticipates that its initial year ROE evaluation would exclude the project costs and revenue recovered in its proposed rider. ENO proposes that the rider would apply until realignment in the 2021 FRP.

ENO insists that it must begin to recover project costs as of the COD. ENO witness Charles Rice says that if the Council takes no action to allow for contemporaneous in-service cost recovery, there would be significant adverse effects on ENO's financial condition.[624] ENO argues that for it to undertake the construction of the first new generation in the City in over forty years, the Company must have assurances of a reasonable opportunity for the timely recovery of its investment and its allowed return on investment.[625] If there is no timely recovery, ENO will not begin to recover O&M expenses, which it will begin to incur as of commercial operation, nor will it begin to recover any depreciation or ROE, until the next rate change in the FRP, or until the next rate case, if there is no FRP.[626]

Intervenor Air Products argues that ENO's proposed exact cost recovery rider is arbitrary because it is "outside mainstream of cost recovery practice."[627] The proposed mechanism, like the PPCACR, would allocate the non-fuel revenue requirement to customers on the basis of kWhs purchased. It is not "cost-based" and is "not an appropriate means of collecting non-fuel revenue requirement."[628]

Air Products explains that the PPCACR was created as a temporary recovery mechanism of the non-fuel revenue requirement, on a kWh basis, associated with the Ninemile 6 PPA. It was intended to remain in place only until the rate case that was contemplated in the Ninemile 6

[624] Rice-4 at 22:22-23:4; Todd-3 at 7:15-8:2.
[625] Rice-4 at 23:4-8.
[626] Todd-3 at. 7:18-8:2.
[627] Brubaker-1 at 4:5-7; Brubaker-2 at 4:8-11, 11:19-22.
[628] Brubaker-1 at 4:7.

proceeding brought the costs into rate base. However, as part of the Algiers transaction, the rate case was deferred until 2018. Subsequently, the Council approved continued use of the PPCACR in connection with costs of the UPS acquisition. Again, Air Products argues, the costs are allocated equally among customer classes on a kWh basis rather than on a cost-based basis.[629]

Air Products points out that under the existing PPCACR, it is paying approximately $1.5 million too much each year from Ninemile 6 and UPS.[630] If a PPCACR were used to allocate the non-fuel revenue requirement for NOPS, Air Products would be allocated approximately $1.06 million instead of the $400,000 it would be allocated if the 1.2% base rate allocation factor were used instead.[631]

Air Products argues that the best approach is a class cost of service study, but in absence of that, the "appropriate approach would be to apply a uniform percentage factor to the base rate revenues of all customer classes. This would essentially preserve existing rate relationships, and would be consistent with generally accepted cost of service principles."[632] Air Products also suggests that the non-fuel cost could be capitalized and deferred for consideration in a subsequent rate case or annual review as part of an FRP.[633]

The Advisors agree that in accordance with regulatory principles, ENO should have a full and fair opportunity to recover prudently incurred costs that are approved by the Council. But

[629] Brubaker-2 at 11:10-18.
[630] Brubaker-2 at 4:8-15; 13:11-17.
[631] Brubaker-2 at 14:4-8.
[632] Brubaker-2 at 12:3-11.
[633] Brubaker-2 at 4:16-21; 14:12-17.

reasonable opportunity to recover investment and a fair return is not a guarantee of dollar-for-dollar cost recovery. At the hearing, ENO's witness Lovorn-Marriage conceded this point.[634]

A utility's revenue requirement should be based on the utility's overall costs, and all cost recovery rate mechanisms should derive from that basis. Designing rates from a separate or singular cost analysis may not include the overall impacts considered in a utility's total revenue requirement by not reflecting offsetting changes from other areas of the utility's operations. While in any given year a utility may over- or under-recover its revenue requirement for a number of reasons,[635] prolonged implementation of the type of rider ENO proposes exacerbates the risk that costs and cost recovery are not properly allocated to those responsible for or benefiting from the cost.

Departure from these general ratemaking principles should occur only under limited circumstances where it has been conclusively shown that failure to allow contemporaneous exact cost recovery would have a severe adverse impact on the utility. ENO has not made any such showing. It has not demonstrated that its financial stability and credit ratings would be adversely affected if the opportunity for cost recovery were provided by means other than a contemporaneous exact cost recovery rider. ENO has only provided general statements, without any credible analysis, that "prolonged regulatory lag on recovery of a substantial investment like NOPS could severely limit the Company's ability to make other required investments and respond to emergency conditions."[636] Because ENO has not demonstrated that its proposed rider is reasonable or necessary, the Advisors urge the Council to reject it. In the likely event that the commercial operation date is later than the test periods and effective date of the Combined Rate

[634] Hr'g Tr. 12/20/17, 60:6-15.
[635] Hr'g Tr. 12/20/17, 60:16-20.
[636] Rice-4 at 22:19-23:8.

Case rates, the Advisors instead support recovery of project fixed costs through the two-step rate case mechanism proposed by Advisors witness Prep. Thus, the NOPS costs should be evaluated in conjunction with the total costs of ENO (including the return component), where total ENO retail revenue adjustment is determined based on a comprehensive evaluation of all costs and revenues.

The cost recovery of NOPS project fixed costs can be evaluated during the Council's consideration of the Combined Rate Case which is expected to conclude by mid-year 2019, and NOPS cost recovery can be accommodated through rates based on pro-formed costs in the Combined Rate Case test period. The targeted commercial operation date of either NOPS alternative would be relatively close to the effective date of revised rates from the Combined Rate Case and the subsequent annual revenue adjustments. Furthermore, in past rate actions ENO has not hesitated to support a comprehensive forward-looking approach toward cost recovery by including several pro-forma adjustments applicable to the prospective period(s) in which new rates would be effective. After the Council's complete vetting of the revenue requirement impacts of the NOPS alternative relative to total ENO operations in the Combined Rate Case, the Council can decide on the timing of any step rate changes for NOPS cost recovery that may be appropriate to correlate with NOPS commercial operation.[637]

Further, Mr. Prep argues that if the Council does not establish an FRP in the Combined Rate Case, an evaluation of NOPS cost recovery and related revenue adjustment can occur with a decoupling mechanism consistent with the Council's guidance in Resolution No. R-16-103.

Advisor witness Prep sets forth how this proposed two-step rate adjustment would work:

---

[637] Prep-1 at 20:3-21:5.

> If an FRP is approved by the Council, the first step would occur with new rates anticipated to be effective by August 1, 2019. The second step would occur with the COD of the NOPS project, which is anticipated to be no sooner than 2020. Depending on the structure of an approved FRP, the FRP would be filed by May 31, 2020, and an adjustment to base rate revenue (including the two step increase, depending on the timing of a COD in 2020) could occur in October 2020. The first FRP adjustment would be based on a 2019 test year and customer class allocations from the Combined Rate Case including pro-forma costs of the NOPS project.
>
> If an FRP is not approved, the second step increase would still occur with the COD of the NOPS project. The stand-alone full decoupling adjustment would be filed annually by May 31, 2020, maintaining the total utility fixed cost revenue requirement approved in the Combined Rate Case with the limited exception that the revenue requirement be reset with a substantial change to the fixed cost of service, such as the addition of new generating capacity (NOPS).
>
> In either of the FRP and stand-alone decoupling cases, the two step rate increase would apply with the project COD, and there would be three years of revenue adjustments based on the project fixed costs updated in each test period.[638]

During the hearing, ENO witness Todd conceded that ENO's concern is the Company's ability to start recovering its costs when NOPS is placed into service.[639] He acknowledged that other mechanisms, such as the two-step rate case proposed by Advisors witness Prep would accomplish ENO's goal and would be acceptable to the company.[640] ENO witness Lovorn-Marriage similarly stated that Advisors witness Prep's suggestion of two-phase rate case acceptable because that would accomplish recovery contemporary with the in-service date.[641]

[638] Prep-1 at 22:7-23:5.
[639] Hr'g Tr. 12/19/17, 130:16-23.
[640] Hr'g Tr. 12/19/17, 130:24-131:1, 132:1-4.
[641] Hr'g Tr. 12/20/17, 50:2-20.

Todd also agreed that the kilowatt basis used by the current PPCACR is not appropriate for NOPS investment recovery.[642] In allocating project non-fuel/fixed costs to customer classes, a demand cost allocation methodology is much more appropriate than a kWh-based allocation.[643] If Advisors witness Prep's cost recovery mechanism is used, non-fuel O&M costs and investment would not be based on a per-kWh basis.[644]

ENO witness Lovorn-Marriage also agreed with the principle that costs should be allocated to the customers who caused the costs, and for this reason, for non-fuel requirements associated with generation facilities, capacity related costs on an embedded class cost-of-service study typically would be allocated using a demand allocator. She said she agreed with AP Witness Brubaker that "in the absence of a class cost-of-service study, the appropriate approach for the PPCACR rider would be to apply a uniform percentage factor to base rate revenues for all customer classes" and that "[t]ypically you would allocate costs consistent with a base rate."[645]

Based on the evidence in the record, and given that even ENO's own witnesses have conceded that the PPCACR mechanism, as proposed, is not an appropriate cost recovery mechanism for NOPS, the Advisors do not recommend recovery of project fixed costs through a rider as proposed by ENO. Instead, base rate revenues should be used to develop a current estimate of the project fixed costs allocated to customer classes, with the final allocation methodology to be determined in the Combined Rate Case. In the event that the commercial operation date is later than the test periods and effective dates of the Combined Rate Case rates,

---

[642] Hr'g Tr. 12/19/17, 131:18-25.
[643] Hr'g Tr. 12/19/17, 134:18-135:7.
[644] Hr'g Tr. 12/19/17, 134:12-16.
[645] Hr'g Tr. 12/20/17, 49:5-50:8; 57:17-58:6.

the recovery of project fixed costs should be accomplished using the two-step increase or adjustment to base rates that Advisors witness Prep has set forth.

B. LTSA cost recovery

In addition to the rider, ENO is contemplating entering an LTSA with the original equipment manufacturer for major maintenance. It has a term sheet with the original equipment manufacturer for the CT[646] and is exploring whether an LTSA is possible for the RICE Alternative.[647] The Company has not has not determined whether an LTSA for the RICE Alternative is feasible.[648] The LTSA for the CT would include planned and unplanned maintenance (subject to cost ceilings), remote monitoring and diagnostics, combustion system tuning services, and an on-site technical advisor. The manufacturer would be required to maintain the reliability, output and efficiency of the unit, as well as NOx and CO emissions and turbine vibration. It also would limit the duration of scheduled outages.[649]

If an LTSA is executed before the COD, ENO requests authorization to recover the LTSA expenses through the FAC.[650] As discussed above, maintenance costs on a non-variable or transactional basis would be recovered in base rates.[651] ENO asserts that use of the FAC for recovery of LTSA costs is appropriate because (1) the expenses are variable to the extent that major maintenance (and related payments) is based on utilization, including unit starts and run-time of the facility, and (2) customers pay actual LTSA costs when incurred, whereas recovery through base rates runs a risk that ENO recovered more or less than the actual costs incurred.[652]

[646] Breedlove-1 at 7:9-21.
[647] Breedlove-3 at 2:19-20.
[648] Todd-3 at 4:6-8; 8:19-20.
[649] Breedlove-1 at 8:5-12.
[650] Todd-1 at 10:8-17; Todd-3 at 8:20-23.
[651] Todd-1 at 11:7-12; Todd-3 at 9:13-15.
[652] Todd-1 at 10:12-17; Todd-3 at 8:23-9:8.

Todd explains that LTSA expenses associated with Ninemile 6 and UPS are recovered through the FAC, but that such recovery is non-precedential, therefore ENO must receive Council authorization in order to include NOPS LTSA expenses in the FAC.[653]

ENO notes that recovery of MISO market settlement revenues and expenses associated with either the CT or the RICE Alternative would occur through the currently-approved mechanism, *i.e*., the costs would be included in the Company's FAC, except that administrative expenses and revenues would be recovered through ENO's MISO Cost Recovery Rider.[654]

The Advisors recommend against ENO's requested approach for recovery of LTSA costs. The LTSA costs are primarily fixed costs similar to traditional project fixed maintenance costs, and should be recovered through base rates using appropriate cost allocations, rather than through the FAC as proposed by ENO. LTSA costs include certain major maintenance, and can vary somewhat depending on the starts and actual run hours of the unit. However, they do not tend to fluctuate widely to the extent that fuel costs do.[655]

Indeed, not all variable costs go into the FAC. The primary purpose of the FAC is to recover fuel costs.[656] The LTSA does not directly include any fuel costs.[657] There are some variable costs other than fuel costs that are recovered in ENO's FAC,[658] but on cross-examination, ENO Witness Todd conceded that, not all variable costs are in the FAC.[659] Mr.

[653] Todd-1 at 10:21-11:2.
[654] Todd-1 at 11:16-21; Todd-3 at 9:20-10:3.
[655] Prep-1 24:9-25:5.
[656] Hr'g Tr 12/19/17, 140:25-141:3.
[657] Hr'g Tr. 12/19/17, 145:14-18.
[658] Hr'g Tr. 12/19/17, 143:1-13.
[659] Hr'g Tr. 12/19/17,10-23; 142:9-14.

Todd also admitted that as a general rule, costs that are permitted to be recovered through the FAC are typically costs with wide fluctuation.[660]

Advisors witness Prep reviewed treatment of LTSA costs in other retail jurisdictions and found that the general consensus among regulatory bodies is to recover LTSA costs in base rates.[661] ENO witness Lovorn-Marriage remarks that the Louisiana Public Service Commission has allowed recovery of LTSA costs through Entergy Louisiana, LLC's FAC, but provides no discussion of the circumstances of those approvals other than a general statement that those LTSAs were in connection with combined cycle units and contained terms similar to what ENO expects would be in a NOPS LTSA.[662]

Allowing ENO to recover its LTSA maintenance costs for NOPS through the FAC rider would include more fixed costs in ENO's FAC at a time when the Council should be considering in the Combined Rate Case the elimination of such occurrences in the interest of an equitable cost allocation among the rate classes. The FAC was originally designed to flow variable costs such as fuel through to ratepayers on a per-kWh of usage basis. Continued loading in the FAC of fixed costs that do not vary with kWh use is contrary to this intent and results in improper allocation of those costs. LTSA costs are expected to be regularly occurring and predictable.[663] As such, ENO should be allowed to recover any prudently incurred LTSA costs through the same cost recovery mechanism that the Council ultimately approves for all other NOPS fixed/non-fuel costs.[664]

[660] Hr'g Tr. 12/19/17, 141:18-23.
[661] Prep-1 25:8-14.
[662] Lovorn-Marriage-2 at 7:12-17.
[663] Prep-1 at 24:9-11.
[664] Prep-1 at 24:11-25:2.

The Advisors are not persuaded that it has been demonstrated that LTSA costs would be of the sort that are appropriate for inclusion in the FAC, as opposed to recovery through base rates. Assuming that an LTSA is executed – which, based on the record, is speculative at this point – there is no evidence that the anticipated LTSA costs would fluctuate widely or be so unpredictable as to warrant that they be treated separately from other O&M costs associated with the project. The LTSA costs are primarily fixed costs similar to traditional project fixed maintenance costs, and should be recovered through base rates using appropriate cost allocations, rather than recovery through the FAC as proposed by ENO.[665] The Advisors therefore urge rejection of ENO's request to include LTSA costs in the FAC and recommend their inclusion in base rates as discussed by Advisor witness Prep.

C. Rate Impact

ENO did not initially include an analysis of the impact of NOPS on customer bills, but did so in response to a discovery request by the Advisors. Advisors witness Watson includes a table and explanation of ENO's analysis in his testimony.[666] ENO estimates the typical monthly bill impacts of the two proposed NOPS units as follows:

	RICE Alternative	CT Alternative
Residential (1000 kWh)	$7.19	$5.61
Commercial (9,125 kWh)	$65.62	$51.16
Industrial (91,250 kWh)	$656.19	$511.57

Watson explains that in estimating typical monthly bill impacts, ENO first calculated an incremental supply cost by case and by year (*i.e.*, an incremental revenue requirement impact). ENO then levelized and unitized these incremental supply costs by calculating their present

[665] Prep-1 at 24:6-25:2.
[666] Watson-1 at 13:1-14:2.

value (PV) across 17 years and then dividing that PV value by the PV of forecasted MWh sales across the same timeframe, resulting in a levelized $/kWh bill impact for each case (a single $/kWh value for all rate classes similar to the per-kWh cost allocation methodology in the existing PPCACR Rider). ENO then multiplies its levelized $/kWh bill impact by a typical monthly consumption by rate class to present a levelized $/mo typical bill impact.[667]

Advisors witness Watson disagreed with ENO's methodology and instead estimated the monthly bill impact based on an allocation of fixed costs among the rate classes (based on 2016 base-rate revenues), and an allocation of variable costs based on kWh consumption (*i.e.*, using the cost recovery method suggested by Advisors witness Prep).[668] Advisors witness Watson then estimated typical monthly bill impacts under several scenarios:[669]

[667] Watson-1 at 13:7-14:2.
[668] Watson-1 at 14:14-16.
[669] Watson-1 at 15:2.

Typical Monthly Bill Impact (Reflects a MISO PRA MCP of $6.00/kW-year and an ROE of 9.75%)			
Case	**Residential Typical Bill Impact (1,000 kWh/mo)**	**Commercial Typical Bill Impact (9,125 kWh/mo)**	**Industrial Typical Bill Impact (91,250 kWh/mo)**
Cases w/o Additional DSM Measures			
RICE Alternative	$6.43	$44.87	$333.84
CT Alternative	$6.79	$47.75	$360.26
Cases w/ the Council's 2% DSM Goal			
RICE Alternative	$22.41	$160.13	$1,170.70
CT Alternative	$22.81	$163.31	$1,199.08

The DSM bill impacts were modeled using the costs of achieving the Council's 2% DSM Goal as estimated by Navigant in its June 2017 DSM Potential Study.[670]

ENO disagrees with the Advisors' billing impact estimates. According to ENO witness Cureington, the Council's 2% DSM Goal is unachievable and unsustainable over the long-term planning horizon. He also says that the assumed MISO PRA clearing prices will not remain constant over the planning horizon. Because these assumptions are not reasonable, he says, the Advisors' estimated bill impacts are not reasonable.[671]

ENO's estimate also uses an assumed ROE of 11.1%, so their rate impact estimates are higher than the Advisors' estimates. Watson used an ROE of 9.75%. He does not advocate any specific ROE at this time,[672] but notes that 9.75% is in line with ROEs recently set by retail regulators.[673]

---

[670] Watson-1 at 15:6-8.
[671] Cureington-7 at 8:5–11.
[672] Watson-1 at 17:14–18:8; 18:12; 19:3.
[673] Watson-1 at 17:1-13; 18:12-16.

The Advisors recommend that the Council use witness Watson's billing impact estimates in their evaluation of ENO's application. Setting aside the disagreement over the impact of the Council's 2% DSM Goal and the impact of the MISO market prices, ENO's estimates are based on an ROE that is significantly higher than the typical ROEs that have been approved recently. Inclusion of this higher ROE pushes up the cost estimates, which in turn inflates the billing impact estimates.

D. Monitoring Plan

If the Council approves construction of NOPS, ENO's requested monitoring and reporting requirement should be modified. ENO proposes reporting to the Council quarterly on the status of NOPS and provided a proposed monitoring plan.[674] Advisors witness Rogers generally agrees with the proposal, but recommends that the Council build in the ability to modify the reporting to the extent that desired additional information is available and does not place an undue burden on ENO.[675] Quarterly reports typically provide only summary-level information, and the Council will want to fully understand developments, particularly if there are changes in costs or project schedule, among other things. If the Council elects to construct NOPS, the Advisors recommend that ENO's requested monitoring and reporting requirements be modified as identified by Advisor witness Rogers.

Conclusion

Wherefore, for the foregoing reasons, the Advisors recommend that the Council:

1. Find that the RICE Alternative serves the public convenience and necessity and is in the public interest, and therefore prudent.

[674] Rogers-1 at 3:16-18, 49:13-19.
[675] Rogers-1 at 49:8-12.

2. Confirm that the Company will have a full and fair opportunity to recover all prudently incurred costs.

3. Find that the cost recovery of NOPS project fixed costs can be evaluated during the Council's consideration of the Combined Rate Case to be filed in 2018, and cost recovery shall be accommodated through a two-step rate adjustment. After the Council's complete vetting of the revenue requirement impacts of the NOPS project relative to total ENO operations in the Combined Rate Case, the Council can decide on the timing of any step rate adjustments to reflect NOPS cost recovery that may be appropriate to correlate with NOPS date of commercial operation. If the Council does not establish an FRP in the Combined Rate Case, an evaluation of NOPS cost recovery and related revenue adjustment could occur with a decoupling mechanism consistent with the Council's guidance in Resolution No. R-16-103.

4. Find that any costs associated with an LTSA should be recovered through base rates using appropriate cost allocations.

5. Approve ENO's proposed Monitoring Plan, with an additional provision that the reporting requirement may be adjusted at the request of the Advisors unless ENO can demonstrate that such a request would create an undue burden on the Company.

6. Require that ENO demonstrate its compliance with all applicable laws and regulations by filing with the Council all permits granted, and orders or rulings issued by any agency with jurisdiction over the project, including but not limited to, the EPA and LDEQ.

Respectfully submitted,

Walter J. Wilkerson
Wilkerson & Associates, PLC
650 Poydras Street, Suite 1913
New Orleans, Louisiana 70130
Phone: (504) 522-4572
Facsimilie: (504) 522-0728
Email: wwilkerson@wilkersonplc.com

Clinton A. Vince
Emma F. Hand
Presley R. Reed, Jr.
Dentons US LLP
1900 K Street, N.W.
Washington, D.C. 20006
202-408-6400 (Telephone)

202-408-6399 (Facsimile)
clinton.vince@dentons.com
emma.hand@dentons.com
presley.reedjr@dentons.com

Jerry A. Beatmann, Jr. (Bar No. 26189)
Dentons US LLP
650 Poydras Street, Suite 2850
New Orleans, LA 70130
504-524-5446 (Office)
504-256-6142 (Cell)
jay.beatmann@dentons.com

Certificate of Service

I hereby certify that a copy of the foregoing has been served upon "The Official Service List" via electronic mail and/or U.S. Mail, postage properly affixed this 19th day of January, 2018.

SERVICE LIST

Lora W. Johnson, lwjohnson@nola.gov
Clerk of Council
City Hall - Room 1E09
1300 Perdido Street
New Orleans, LA 70112
(504) 658-1085 - office
(504) 658-1140 – fax

W. Thomas Stratton, Jr., wtstrattonjr@nola.gov
Director, Council Utilities Regulatory Office
City Hall - Room 6E07
1300 Perdido Street
New Orleans, LA 70112
(504) 658-1110 - office
(504) 658-1117 – fax

David Gavlinski, 504-658-1101, dsgavlinski@nola.gov
Interim Council Chief of Staff
City Hall - Room 1E06
1300 Perdido Street
New Orleans, LA 70112

Rebecca Dietz, rhdietz@nola.gov
Bobbie Mason, bfmason1@nola.gov
Law Department
City Hall- 5th Floor
New Orleans, LA 70112

(504) 658-9800 – office
(504) 658-9869 – fax

Beverly Gariepy, bbgariepy@nola.gov
Department of Finance
City Hall - Room 3E06
1300 Perdido Street
New Orleans, LA 70112
(504) 658-1502- office
(504) 658-1705 – fax

ADMINISTRATIVE HEARING OFFICER

Hon. Jeffrey S. Gulin, jgulin@verizon.net
3203 Bridle Ridge Lane
Lutherville, MD 21093
(410) 627-5357

NEW ORLEANS CITY COUNCIL CONSULTANTS

Clinton A. Vince, clinton.vince@dentons.com
Presley Reed, presley.reedjr@dentons.com
Emma F. Hand, emma.hand@dentons.com
DENTONS US LLP
1900 K Street NW
Washington, DC 20006
(202) 408-6400 - office
(202) 408-6399 - fax

Basile J. Uddo (504) 583-8604 cell, buddo@earthlink.net
J. A. "Jay" Beatmann, Jr. (504) 256-6142 cell, (504) 524-5446 office direct, jay.beatmann@dentons.com
c/o DENTONS US LLP
650 Poydras Street
Suite 2850
New Orleans, LA 70130

Walter J. Wilkerson, wwilkerson@wilkersonplc.com
Kelley Bazile, kbazile@wilkersonplc.com
Wilkerson and Associates, PLC
650 Poydras Street - Suite 1913
New Orleans, LA 70130
(504) 522-4572 - office
(504) 522-0728 - fax

Joseph Vumbaco, jvumbaco@ergconsulting.com
Joseph W. Rogers, jrogers@ergconsulting.com
Victor M. Prep, vprep@ergconsulting.com
Byron S. Watson, bwatson@ergconsulting.com
Legend Consulting Group
8055 East Tufts Ave., Suite 1250
Denver, CO 80237-2835
(303) 843-0351 - office
(303) 843-0529 – fax

Errol Smith, ersmith@btcpas.com
Bruno and Tervalon
4298 Elysian Fields Avenue
New Orleans, LA 70122
(504) 284-8733 - office
(504) 284-8296 – fax

ENTERGY NEW ORLEANS, INC.

Gary E. Huntley, ghuntley@entergy.com
Entergy New Orleans, Inc.
Vice-President, Regulatory Affairs
1600 Perdido Street, L-MAG 505B
New Orleans, LA 70112
(504) 670-3680 - office
(504) 670-3615 - fax

Seth Cureington, scurein@entergy.com
Entergy New Orleans, Inc.
Manager, Resource Planning
1600 Perdido Street, L-MAG 505B
New Orleans, LA 70112

504-670-3602 office
504-670-3615 fax

Tim Cragin (504) 576-6523 office, tcragin@entergy.com
Brian L. Guillot (504) 576-2603 office, bguill1@entergy.com
Alyssa Maurice-Anderson (504) 576-6523 office, amauric@entergy.com
Harry Barton, hbarton@entergy.com
Karen Freese (504) 576-4170 office, kfreese@entergy.com
Entergy Services, Inc.
Mail Unit L-ENT-26E
639 Loyola Avenue
New Orleans, LA 70113
(504) 576-5579 – fax

Joe Romano, III (504) 576-4764, jroman1@entergy.com
Suzanne Fontan (504) 576-7497, sfontan@entergy.com
Danielle Burleigh (504) 576-6185, dburlei@entergy.com
Therese Perrault (504-576-6950), tperrau@entergy.com
Entergy Services, Inc.
Mail Unit L-ENT-4C
639 Loyola Avenue
New Orleans, LA 70113
(504)576-6029 – fax

ALLIANCE FOR AFFORDABLE ENERGY

Logan Atkinson Burke, (646) 942-7149, logan@all4energy.org
Forest Wright, forest@all4energy.org
Sophie Zaken, regulatory@all4energy.org
4505 S. Claiborne Ave.
New Orleans, LA 70125

Susan Stevens Miller, (202) 667-4500, smiller@earthjustice.org
Chinyere Osuala, (202) 667-4500, cosuala@earthjustice.org
Al Luna, (202) 667-4500, aluna@earthjustice.org
1625 Massachusetts Ave., NW Ste 702
Washington D.C. 20036

POSIGEN

Benjamin Norwood, bnorwood@posigen.com
Beth Galante, bgalante@posigen.com
819 Central Ave. Suite 210
Jefferson, LA. 70121
(504)293-5665

AIR PRODUCTS AND CHEMICALS, INC.

Ernest L. Edwards Jr, ledwards0526@gmail.com
The Law Offices of Ernest L. Edwards Jr, APLC
300 Lake Marina Avenue unit 5BE
New Orleans, LA 70124
Phone: 504 450-4226

Mark Zimmerman, zimmermr@airproducts.com
Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501
610-481-1288 - office
610-481-2182 – fax

Maurice Brubaker, (636) 898-6725, mbrubaker@consultbai.com
Brubaker & Associates, Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

James R. Dauphinais, (636) 898-6725**,** jdauphinais@consultbai.com
Brubaker & Associates, Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

DEEP SOUTH CENTER FOR ENVIRONMENTAL JUSTICE, INC.

Monique Harden, (504) 517-2534,MoniqueCovHarden@gmail.com
3157 Gentilly Blvd., #145
New Orleans, LA 70122

NEW ORLEANS COLD STORAGE & WAREHOUSE CO., LTD.

Luke Piontek, LPiontek@roedelparsons.com
Judith Sulzer, Jsulzer@roedelparsons.com
Gayle T. Kellner
Christian J. Rhodes
Shelley Ann McGlathery
Roedel, Parsons, Koch, Blache,
Balhoff & McCollister
8440 Jefferson Highway, Suite 301
Baton Rouge, LA 70809

Telephone: (225) 929-7033
Facsimile: (225) 928-4925

GULF STATES RENEWABLE ENERGY INDUSTRIES ASSOCIATION

Jeff Cantin, President, (504) 383-8936, jcantin@gsreia.org
Will Feldman, (818) 631-9884, wfeldman@gsreia.org
400 Poydras St., Suite 900
New Orleans, LA 70130

SIERRA CLUB

Joshua Smith, joshua.smith@sierraclub.org
Sierra Club Environmental Law Program
2101 Webster St., Suite 1300
Oakland, CA. 94612
(412) 977-5560

Robert B. Wiygul, robert@wwglaw.com
Waltzer, Wiygul, & Garside, LLC
1011 Iberville Dr.
Ocean Springs, MS 39564
(228)872-1125

Michael Brown, michael@wwglaw.com
Waltzer, Wiygul, & Garside, LLC
1000 Behrman Hwy
Gretna, LA 70056
(504)340-6330