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July 6, 2017

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

> **_Re: Supplemental and Amending Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief_**
> **_CNO Docket NO.: UD-16-02_**

Dear Ms. Johnson:

Please find enclosed for your further handling an original and three copies of the Public Supplemental and Amending Application of Entergy New Orleans, Inc. ("ENO") for Approval to Construct New Orleans Power Station and Request for Cost Recovery and for Timely Relief. This filing includes the Supplemental and Amending Direct Testimony and Exhibits of Charles L. Rice, Jr., Seth E. Cureington, Jonathan E. Long, Charles W. Long, Bliss M. Higgins, Dr. George Losonsky, Orlando Todd, and Robert A. Breedlove. Please file an original and two copies into the record in the above referenced matter, and return a date stamped copy to our courier.

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

Thank you for your assistance with this matter.

Sincerely,

Brian L. Guillot

Enclosures

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

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

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

Entergy New Orleans, Inc. ("ENO" or the "Company") respectfully submits this Supplemental and Amending Application[1] ("Supplemental Application") to the Council of the City of New Orleans ("Council"), which seeks, among other requests, authorization to proceed with constructing the New Orleans Power Station ("NOPS" or the "Project"), which will consist of either a combustion turbine ("CT") resource with a summer capacity of 226 megawatts ("MW"), or alternatively, seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator sets ("Alternative Peaker").[2] Either facility would be located at ENO's Michoud facility in New Orleans East. In addition to a finding that the construction of NOPS is in the public interest, the Company also requests approvals relating to appropriate cost recovery, a construction monitoring plan, and a procedural schedule to permit a Council decision on this

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[1] The Company hereby files this Supplemental and Amending Application to propose a smaller resource as an alternative to its original CT application. To be clear, however, the original CT is still a prudent option for the Council's consideration; and accordingly, the Company hereby incorporates herein its original Application by reference, including all Direct Testimony filed therewith and the November 2016 Supplemental Testimony filed in support of New Orleans Power Station.

[2] The use of "NOPS" throughout this Supplemental Application and supporting testimony refers to either the original CT or the Alternative Peaker.

Application no later than October 2017. In support of these requests, the Company represents the following:

INTRODUCTION

I.

ENO is an electric and gas utility organized and operating under the laws of the State of Louisiana, with its general office and principal place of business at 1600 Perdido Street, Building 505, New Orleans, Louisiana 70112. The Company is engaged in the manufacturing, production, transmission, distribution, and sale of electricity to residential, commercial, industrial, and governmental consumers throughout Orleans Parish. ENO furnishes electric service to approximately 200,000 retail electric customers in Orleans Parish. ENO is also engaged in the provision of natural gas service throughout New Orleans and serves approximately 107,000 retail gas customers.

II.

In January 2017, as discussed more fully by Company witness Seth E. Cureington, the Company received an updated forecast of projected peak customer demand for the 20-year planning horizon. The updated load forecast was created by Entergy Services, Inc. ("ESI")[3] for the purpose of updating the Company's financial plans, including its sales forecast and financial models. ESI periodically updates its forecast of future customer demand for these reasons, and the information is also used to update the EOCs' long-term capacity needs and long-term transmission planning.

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[3]   ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), ENO, and Entergy Texas, Inc. ("ETI").

As Mr. Cureington discusses, according to the updated load forecast, the Company's projections of customer demand have moderated by an average of 3.4% per year (average of 40 MW per year) compared to the forecast used in the original Application. Accordingly, on February 14, 2017, after the Intervenors in this docket filed their Direct Testimony but before the Council's Advisors filed Direct Testimony, the Company filed a Motion to Suspend the procedural schedule in this docket in order to analyze the implications of the updated forecast and to ensure that the Company takes the best course of action for its customers.

III.

Following the referenced Motion to Suspend, ENO has analyzed the implications of the updated forecast and has concluded that the original unit proposed to the Council, a 226 MW CT, still has significant benefits for customers and should be constructed. The Company also found, however, that the construction of a smaller unit would also create significant benefits and should also be considered by the Council. Accordingly, the Company now files this Supplemental and Amending Application proposing that the Council either (1) approve the originally proposed CT, or (2), approve the alternative smaller resource, which will be discussed throughout this filing.

IV.

As discussed by Mr. Cureington, ENO still emphatically needs a new local resource. The recent deactivations of Michoud Units 2 and 3, which were economic decisions based on maintenance and other operational and economic issues, resulted in the loss of approximately 781 MW of local capacity and created a need. In fact, even based on the Company's updated load forecast, the Company still projects a demand for overall capacity, specifically peaking capacity, over the next 20 years. As Mr. Cureington explains, the Company has an overall capacity need of approximately 100 MW for the first ten years of the planning horizon, which

grows to 248 MW in the second ten years of the planning horizon. The Company is also projected to have a peaking and reserve capacity deficit of approximately 342 MW on average throughout the 20 year planning horizon.

While the Company continues to seek opportunities to offset some of its capacity needs with energy efficiency and demand-side management ("DSM") programs, as well as adding renewable resources to its generation portfolio, such resources are not alternatives to NOPS and cannot satisfy ENO's long-term peaking/reserve capacity deficit. Neither is it feasible for the Company to rely on the Midcontinent Independent System Operator, Inc. ("MISO") capacity market for its long-term capacity needs. Further, as discussed more fully below, the Company has a long-term planning need for a local resource that can support local reliability, reduce reliance on transmission and resources external to Orleans Parish, and facilitate storm restoration.

V.

The Company also requests that the Council issue the approvals requested herein no later than October 31, 2017. This procedural schedule will allow the Company to issue timely notice to proceed ("NTP") to the engineering, procurement, and construction ("EPC") services contractor selected for the Project.

VI.

The Council should also be aware that the current cost estimate for the original CT has increased by $16 million, as discussed by Company witness Jonathan E. Long, bringing the overall cost estimate to approximately $232 million. The new anticipated Commercial Operation Date ("COD"), provided regulatory approval is received by the end of October 2017 and NTP is granted to the EPC contractor by November 1, 2017, is approximately November 2020.

VII.

The current cost estimate for the Alternative Peaker is $210 million. The anticipated COD, provided regulatory approval is received by the end of October 2017 and NTP is granted to the EPC contractor by November 1, 2017, is expected in October 2019.

VIII.

With this Supplemental and Amending Application, the Company is submitting the Supplemental and Amending Direct Testimonies of Charles L. Rice, Jr., Seth E. Cureington, Jonathan E. Long, Charles W. Long, Bliss M. Higgins, George Losonsky, Ph.D., Orlando Todd, and Robert A. Breedlove. The purpose of the testimony of each witness is as follows:

- **Charles L. Rice, Jr.** – Mr. Rice, President and Chief Executive Officer of ENO, provides an overview of the Supplemental Application. He also introduces the testimony of the other witnesses supporting the Supplemental Application.

- **Seth E. Cureington** – Mr. Cureington is the Director, Resource Planning and Market Operations for ENO. Mr. Cureington discusses the circumstances surrounding the updated load forecast referenced in ENO's February 14, 2017 Motion to Suspend, and how the Company is still in need of long-term capacity, and in particular peaking and reserve capacity. He explains why local generation is needed, and the results of modeling conducted on behalf of the Company and the Council's Advisors.

- **Jonathan E. Long** – Mr. Jonathan Long is the Vice President, Capital Projects for ESI. He provides an overview of the updated cost estimate and timeline for the CT. He also provides an overview of the Alternative Technology. He also describes the management approach that the Company intends to employ and the EPC contractor selected for the Alternative Peaker.

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- **Charles W. Long** – Mr. Charles Long is the Director of Transmission Planning for ESI. He describes, from the transmission perspective, the unique characteristics of the Downstream of Gypsy ("DSG") region and how the construction of either the CT or Alternative Peaker will have the effect of avoiding/delaying projects that would otherwise be necessary to maintain reliability. Mr. Long also describes the transmission related reliability benefits associated with constructing the CT and Alternative Peaker.

- **Bliss M. Higgins** – As described above, Ms. Higgins is an expert in air emissions and permitting and has concluded that the CT and the Alternative Peaker will have allowable emissions significantly below those of the former Michoud Plant and that these facilities emissions will comply with the U.S. Environmental Protection Agency ("EPA") National Ambient Air Quality Standards, which were established to be protective of human health, including sensitive populations, with an adequate margin of safety via a lengthy EPA process with extensive and scientific community public involvement.

- **George Losonsky, Ph.D.,** – As described above, Dr. Losonsky is an expert geologist and former Commissioner of the Southeast Louisiana Flood Protection Authority-East. Dr. Losonsky conducted various analyses and concluded that the groundwater withdrawal associated with the CT and Alternative Peaker will not cause incremental subsidence or damage to infrastructure in New Orleans East.

- **Orlando Todd** – Mr. Todd is the Finance Director for ENO. Mr. Todd provides the estimated first-year revenue requirement associated with both NOPS options. He also describes the proposal to recover the costs associated with the Alternative Peaker. In

addition, Mr. Todd explains the proposed Cost Recovery Plan and the importance of timely recovery.

- **Robert A. Breedlove** – Mr. Breedlove is the Director of Plant Support in Fossil Operations. Mr. Breedlove provides the estimated operation and maintenance costs for the Alternative Peaker.

This Supplemental Application, along with the Company's original Application, and the supporting testimony, include the specific data that the Company relied upon in making the decision to construct NOPS, estimates of the costs to construct both NOPS options, the estimated first year, non-fuel revenue requirement associated with both NOPS options, the estimated in-service dates, and the construction schedules and milestones.

OVERVIEW OF RESOURCES

IX.

As described in more detail by Mr. Jonathan E. Long in his Direct Testimony, the Company proposes to construct NOPS, which will consist of either the originally proposed CT or the Alternative Peaker. The technical details regarding the original CT are contained in the Company's original Application.

X.

The Alternative Peaker, as stated above, will consist of seven Wärtsilä RICE generator sets. As explained by Mr. Jonathan E. Long, RICE is a well-known technology used, for example, in automobiles, trucks, marine propulsion, and backup power applications. RICE technology uses the expansion of hot gases to push a piston within a cylinder, converting the linear movement of the piston into the rotating movement of a crankshaft to generate power. In a

power plant, multiple spark-ignited or diesel RICE engines are grouped into blocks of engines, called generating sets, to provide modular electric generating capacity in standardized sizes.

XI.

Based on a study conducted by a qualified engineering firm, WorleyParsons, as described by Mr. Jonathan Long, the RICE units had the lowest levelized cost of electricity on a $/MWh basis compared to alternative CTs in the same output range, as well as other benefits such as very low water usage, a low emissions profile, the ability to support renewable resources, and the inclusion of black-start capability.

XII.

As Mr. Jonathan E. Long also discusses in his Direct Testimony, the current estimated cost to construct the Alternative Peaker is $210 million, which reflects the use of a fixed-price, fixed-duration form of EPC contract, subject to certain defined possible adjustments. The EPC contract accounts for a significant portion of the overall estimated cost of the Project. Other components included in the overall cost estimate are an allowance for funds used during construction ("AFUDC"), transmission interconnection to the switchyard, project contingency, internal construction management, indirect loaders, insurance coverage, expenses related to seeking Council certification, and other non-EPC costs. Charles Long describes the MISO interconnection study process in his Direct Testimony, and provides an update in his Supplemental and Amending Direct Testimony. Interconnection costs are not expected, but MISO's process could identify costs that have not been included in the estimates provided.

XIII.

The estimated costs of operating and maintaining the Alternative Peaker are detailed in the Direct Testimony of Breedlove, and these costs are reflected in the estimated first-year non-

fuel revenue requirement set forth in the Supplemental and Amending Direct Testimony of Mr. Todd.

XIV.

As discussed in the Supplemental and Amended Direct Testimony of Mr. Rice, the construction of the either NOPS project is expected to have a positive impact on the economies of the State of Louisiana and Orleans Parish. Loren C. Scott & Associates, Inc. conducted a study and concluded that the construction and operation of the CT will produce significant economic benefits – totaling hundreds of millions of dollars – in terms of new business sales, household earnings, and jobs in both the State and Parish economies. Benefits result not only from one-time capital expenditures, but also from ongoing operational expenditures that will continue to accrue to the benefit of residents in Orleans Parish as long as the CT is in operation. The Company has engaged Loren C. Scott & Associates, Inc. to perform an analysis of the impacts of the Alternative Peaker, and its economic impact is expected to be similar to the CT's.

PROJECT EXECUTION AND MANAGEMENT

XV.

As explained in the Supplemental and Amending Direct Testimony of Mr. Jonathan Long, Chicago Bridge and Iron, Inc. ("CB&I") would remain the EPC contractor to construct the CT, should the Council choose that option. Regarding the Alternative Peaker, the Company has chosen a different single-source EPC contractor, Burns and McDonnell ("B&M").

XVI.

B&M was selected through a procurement process as a result of its competitive pricing and prior experience with constructing resources that utilize RICE technology. By 2015, B&M had installed a total of 72 RICE engines, with 60 of these being Wärtsilä engines. B&M

constructed a total of 16 power generation facilities utilizing RICE technology. These projects include a 12 engine Wärtsilä plant at the Denton Energy Center in Denton, Texas, which employs the same engines that will be installed at NOPS; and the Southwest Texas Electric Cooperative's Pearsall plant, which is also similar to the Alternative Peaker.

XVII.

Under the fixed-price EPC contract structure, B&M will act as an independent contractor with respect to the engineering, procurement, and construction services defined in the contract's scope of work. B&M also will procure the RICE engines and balance of plant equipment from the original equipment manufacturers ("OEMs"). B&M's procurement of this equipment will allow it full coordination and scheduling of the OEMs in order to meet the fixed-schedule provided in the contract.

XVIII.

As discussed by Mr. Jonathan Long, the Company does not have the in-house capability to provide all of the required EPC services for the Project. The use of an EPC contractor like B&M, which can perform all of these functions under a single contract, is cost-effective and common within the industry for such projects. The Alternative Peaker project will be managed and monitored by the Company through a Project Team, led by a Project Director, with oversight from an Executive Steering Committee ("ESC"). The ESC will provide oversight and strategic direction for the Project and will monitor and provide direction relating to Project performance, key risks, and value drivers that may affect the Project risk profile.

XIX.

As a component of the EPC Agreement, ENO will require B&M to provide opportunities to small and disadvantaged businesses for participation in any subcontracts and purchase orders

let in the performance of its obligations as the EPC contractor. The Company will require B&M to develop and maintain a list of Diverse Subcontractors and Suppliers that will be supplied to ENO on a quarterly basis. Minority-owned businesses, women-owned businesses, veteran-owned businesses, and disabled-veteran-owned businesses, among others, are included within the meaning of "diverse subcontractors and suppliers." B&M will be required to submit a plan for utilizing diverse subcontractors and suppliers to ensure such participation in the construction of the Alternative Peaker.

RESOURCE NEEDS

XX.

As discussed by Mr. Cureington, ENO is still in need of a new local resource in Orleans Parish. The recent deactivations of Michoud Units 2 and 3, which were economic decisions based on maintenance and other operational issues, resulted in the loss of approximately 781 MW of local capacity and created a need. In fact, even based on the Company's updated load forecast, the Company still projects a demand for overall capacity, specifically peaking capacity, over the next 20 years, as discussed above and by Mr. Cureington.

Mr. Charles Long also explains that the City of New Orleans is located in the eastern half of the DSG and Amite South load pockets, and that it is therefore very sensitive to local reliability issues. The City is located in a geographical and electrical peninsula, bordered by water on the north, east, and south. Accordingly, its ability to import power into New Orleans over the transmission grid is limited, which makes the area highly dependent on local generation to meet customer demand. This problem is only amplified by the fact that a large portion of the local fleet that provides reliability in the New Orleans area is aging and deactivating.

XXI.

As discussed more fully by Mr. Cureington, many Amite South and DSG generators have recently been retired, or are nearing the end of their useful lives. Given the ages of many units still in operation, deactivation could happen sooner than planned. The deactivations of Michoud Units 2 and 3, which together made up nearly 800 MW of generating capacity, are perfect examples of this risk. Given the acute sensitivity to reliability issues that ENO's service territory faces, it is prudent for the Company to begin planning for these retirements, which will be decisions made independently of any decision to add generation based on the condition of the particular units at issue. Moreover, Messrs. Cureington and Rice explain that adding a local generator in New Orleans would not only help to address this issue, but would also create a hedge against market and supply related risks in MISO caused by ENO's generation being located outside of the New Orleans Load Zone.

XXII.

Mr. Charles Long also explains that the transmission analysis conducted by the Company indicates that if generation is not added, ENO's system may not remain reliable throughout the planning horizon absent costly transmission upgrades. In fact, if incremental generation is not added, and costly transmission upgrades are not performed, the Company's service territory will face the risk of cascading (or uncontrolled) outages under certain scenarios that would affect most of the New Orleans area. Figure 1 depicts the areas that would be affected by the referenced outages:

Figure 1[4]
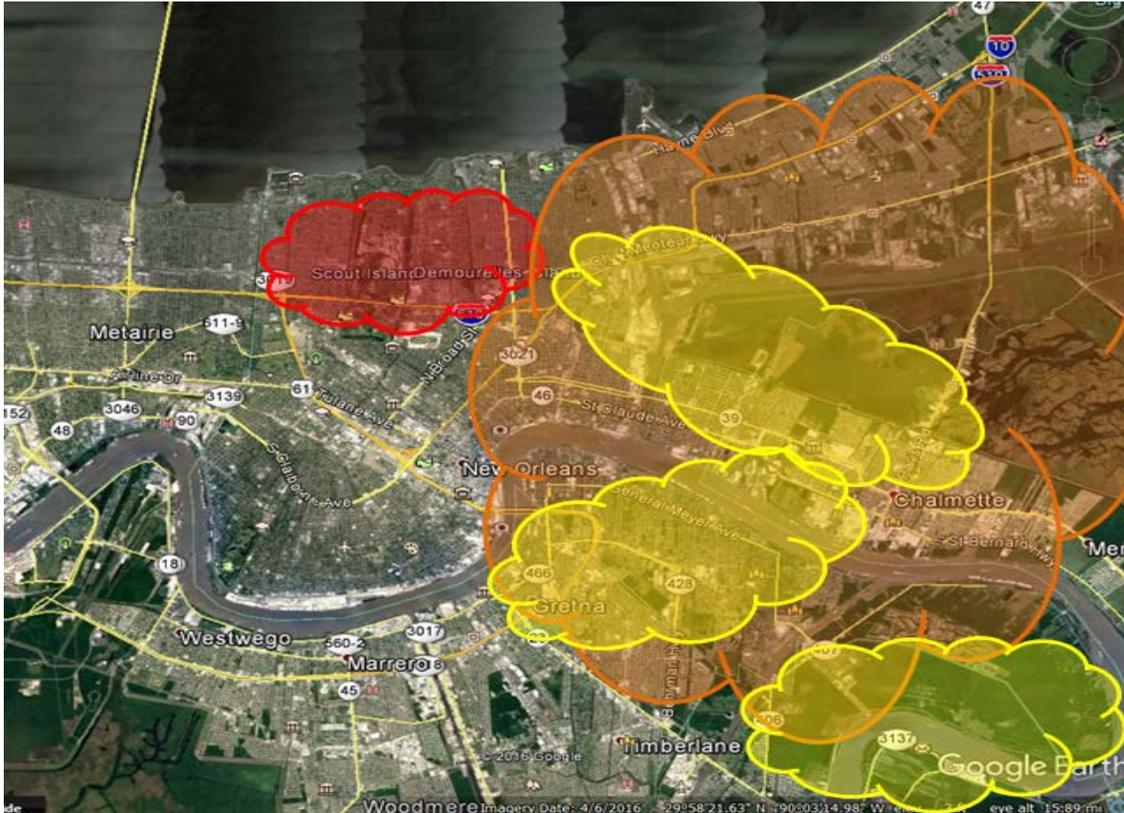
As noted by Mr. Charles Long, adding either the originally proposed CT or the Alternative Peaker would mitigate the potential for these cascading outages.

XXIII.

Messrs. Charles Long and Seth Cureington also explain that a local unit will assist in storm restoration in the event the City of New Orleans becomes islanded (where most of the transmission lines importing power into the city are severed), as it was after Hurricane Gustav. This important benefit of adding local generation cannot be overstated and is consistent with the Council's stated objective to harden the system in preparation for major weather events.

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[4]   *See* Exhibit CWL-6, pg. 4.

Mr. Charles Long also explains that when generating capacity is added to the electric grid, it produces the most transmission-related benefits when located in proximity to the load that it will serve. Locating either NOPS option at the Michoud site will produce the following benefits:

- Increased load-serving capability in the New Orleans area, which is supportive to economic growth;

- Improved ability to serve existing load reliably by reducing the region's dependence on already strained transmission facilities;

- Increased operational flexibility such that necessary maintenance activities for generation and transmission facilities in the area could be planned more efficiently without incurring operational risk during planned outages;

- Increased reactive power, which would improve stability in the DSG region and would thus avoid potential voltage instability and increasing system efficiency by providing reactive power margins to existing customers and supporting future industrial growth; and

- Increased storm restoration benefits, which would help the Company to restore service to customers in a timely manner following a major storm event.

ALTERNATIVE ONE: THE CT

XXIV.

In June 2016, the Company proposed a natural-gas-fueled CT generating facility with a nominal capacity of approximately 226 MW, at summer conditions. Simply put, that CT remains the best option for customers. The Company has an overall capacity need that grows to

approximately 248 MW, and a peaking need of 342 MW on average throughout the 20 year planning horizon. The CT would address a substantial portion of that long-term need.

Moreover, as Mr. Cureington also discusses, the modeling used to estimate the Total Relevant Supply Costs of various portfolios, including those requested by the Council's Advisors at the behest of certain intervenors in this docket who have opposed the construction of NOPS, produced results that were consistent with ENO's original Application in that the CT is the most cost-effective means of addressing the Company's identified long-term planning needs when using the Company's assumptions around capacity prices in MISO. Even under a sensitivity using highly discounted capacity price assumptions, as recommended by intervenors opposed to NOPS, the CT is virtually tied with other portfolios and should therefore prevail given its significant local benefits.

XXV.

It is also important to note that when comparing the CT to the Alternative Peaker, there are some benefits created by the addition of local generation that increase as the size of the local generator increases and which give the CT a slight advantage over the Alternative Peaker because of its 100 MW size advantage. These benefits include the following:

- For reliability purposes, the DSG load pocket is in need of generating capacity to fill the void that will be created by retirements in the aging fleet of local resources. This need favors the addition of more generating capacity, not less.

- The 226 MW CT would eliminate all North American Electric Reliability Corporation ("NERC") reliability issues throughout the 10-year planning horizon, including the cascading outages discussed above and all other reliability issues identified for smaller units in the Company's reliability

analysis.

- As discussed more fully by Mr. Cureington, the larger CT would create a more effective hedge against market and supply related risks in MISO caused by ENO's generation being located outside of the New Orleans Load Zone.

- The larger CT would create larger reliability margins over and above the minimum amount of generation needed for grid stability.

- The larger CT would create more reactive power, more flexibility to take outages, and less dependence on the transmission system than would a smaller unit.

For these reasons, and for the additional reasons provided in testimony supporting this Supplemental and Amending Application, the 226 MW CT remains the best option for customers.

ALTERNATIVE TWO: RICE GENERATOR SETS

XXVI.

In light of the recently updated load forecast, the Alternative Peaker will also provide benefits for ENO customers and should be considered a viable alternative to the originally proposed CT. As discussed above, and more fully by Mr. Jonathan Long, the Alternative Peaker has a low heat rate, low water usage, a low emissions profile, the ability to support renewable resources, and the inclusion of black-start capability.

XXVII.

The Alternative Peaker will also provide many of the same benefits as the larger CT, albeit to a lesser degree because it is 100 MW smaller. To recap, the Alternative Peaker will still add generating in DSG to fill the void that will be created as units in the aging generation fleet

inevitably retire on their own merits, provide a hedge against market and supply related risks in MISO caused by ENO's generation being located outside of the New Orleans Load Zone, add generation to increase the flexibility to take outages to maintain transmission lines and generators, add reactive power, and lessen dependence on the transmission system to meet customer demand. The Alternative Peaker will also provide valuable storm restoration support and would have the ability to aid in islanding the city in an emergency situation.

XXVIII.

Another benefit of the Alternative Peaker, as discussed by Mr. Charles W. Long, is that the unit would also address the cascading, uncontrolled outages under certain contingencies, as discussed above. In fact, if the Alternative Peaker is constructed, then there would only be very minor overloading on the transmission system in planning year 2027. Under this circumstance, the Company would propose to wait until a point-in-time that is closer to the needed upgrades to determine if they are still necessary. Thus, there is a possibility that the Alternative Peaker would also satisfy all NERC reliability criteria.

XXIX.

Also, the Total Relevant Supply Costs of the various portfolios modeled, including under sensitivities around lower than projected capacity prices in MISO, resulted in the Alternative Peaker being competitive with other portfolios that were modeled. Specifically, while the Alternative Peaker was not the lowest cost alternative, its total supply cost ranged from 0.04% lower to 3.99% higher than the "transmission-only" and "100 MW Solar" cases that were modeled (across the entire range of assumptions and sensitivities). Thus, as explained by Mr. Cureington, this result is a virtual tie; and based on ENO's need for a local resource, the Alternative Peaker should be selected over the transmission-only and solar portfolios that were

evaluated given its ability to address local reliability concerns and satisfy a portion of ENO's need for peaking generation.

NON-ALTERNATIVES

XXX.

As Mr. Cureington discusses, renewable resources such as wind and solar are intermittent, as they rely on the wind and sun to produce energy, thus limiting their ability to be counted on to meet peak demands. As a result, renewables must be supported by dispatchable resources such as CT or Alternative Peaker to ensure sufficient resources are available to ramp-up and produce replacement energy when the wind is either not blowing or blowing less than projected, and similarly when cloud cover or unexpected weather limit the output of solar. Finally, because wind and solar are intermittent, these resources would not eliminate the need for quick-start and fast-ramping dispatchable resources. It should also be noted that because they are intermittent, the Company cannot count a megawatt of renewable resource capacity toward meeting a megawatt of its long-term capacity needs. Thus, even if intermittent resources could meet ENO's peaking and reserve needs (which they cannot), the Company would need to acquire/construct significantly more of these resources than its capacity need dictates due to their lower capacity factor.

XXXI.

It should be noted that intermittent resources have a place in ENO's supply portfolio. Indeed, as discussed by Mr. Charles Rice, ENO undertook a Request for Proposals ("RFP") to determine whether there are cost-effective renewable resources available, and has selected three

resources.[5] The RFP was conducted under the supervision of an Independent Monitor. After receiving and reviewing several bids, in May 2017, ENO announced that it had selected three RFP proposals for negotiation of definitive agreements, totaling approximately 45 MW, over twice the original amount sought in the RFP. Of the proposals selected, one is for the acquisition of an approximately 20 MW solar resource to be located in Orleans Parish, the second is for an approximately 5 MW solar self-build rooftop project also to be located in Orleans Parish, and the third involves a 20 MW long-term power purchase agreement from a solar resource to be located near Lafayette, Louisiana. However, without cost-effective storage, which does not exist at this time, it is not possible to utilize intermittent resources to meet ENO's capacity reserve needs and, in turn, ensure reliable service to customers.

XXXII.

The Company is in the process of negotiating contracts with the third-party bidders and firming up other arrangements necessary to allow ENO to prepare the necessary Application(s) with supporting testimony and exhibits to submit to the Council seeking approval to add these projects to ENO's resource portfolio. The contract negotiation process can take several months and is subject to numerous variables that can affect the outcome and timing for completion of negotiations. At this early stage in the process, ENO is tentatively targeting submission of its approval filing(s) sometime in the first quarter of 2018.

XXXIII.

As Mr. Cureington also discusses, achievable DSM resources are not available to meet the Company's peak capacity needs. Indeed, the present load forecast has taken into account all

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[5]   On May 6, 2016, ESI issued a draft request for proposals for renewable generation resources. The RFP will facilitate a market test of the extent, and cost of, renewable resources available to provide benefits in excess of cost to the Company's customers. More information on the Draft RFP can be found on the ESI RFP Website located at: https://spofossil.entergy.com/ENTRFP/SEND/2016ENOIRenewableRFP/Index.htm.

existing energy efficiency and demand side management in ENO's portfolio, and it does not obviate the need for NOPS. Moreover, additional DSM and energy efficiency ("EE") programs are costly to administer and the results therefrom continue to be uncertain. In 2014, the Company engaged ICF International, Inc. ("ICF") to conduct an analysis of the long-term DSM potential achievable in New Orleans. ICF concluded that the achievable amount of DSM in New Orleans is not enough to negate the need for a local resource.

XXXIV.

In order to provide yet another independent evaluation of the long-term DSM potential in New Orleans, the Company recently engaged a second independent consultant, Navigant Consulting, Inc. ("Navigant"), to perform an additional analysis to determine the maximum achievable amount of EE potential savings over a 20-year planning horizon. Using its own methodology and leveraging relevant measures from the stakeholder-informed Arkansas Energy Efficiency Potential Study prepared for the Arkansas Public Service Commission in 2015, Navigant concluded that, under a very aggressive yet maximum achievable scenario, ENO could potentially reduce forecast sales by approximately 0.85%/year over the next 20 years. This level of reduction would cost roughly $400 million, but will not obviate ENO's long-term need for incremental, long-term, local capacity.

ENVIRONMENTAL FACTORS

XXXV.

The Company engaged Dr. George Losonsky, Ph.D., a geologist who formerly served as a Commissioner of the Southeast Louisiana Flood Protection Authority-East, to study the issue of groundwater usage for both plants. Dr. Losonsky conducted various analyses and concluded that the groundwater withdrawal associated with the CT and Alternative Peaker will not cause

incremental subsidence or damage to infrastructure in New Orleans East. Specifically, Dr. Losonsky conducted site-specific calculations to predict a maximum drawdown over a 10-year period, and concluded that the proposed groundwater withdrawal/drawdown rates for the plants in question will be too small to directly affect subsidence or cause damage to buildings and infrastructure at the Michoud site or in New Orleans East.

XXXVI.

The Company also engaged Bliss M. Higgins, who has had a distinguished career at the Louisiana Department of Environmental Quality ("LDEQ"), the agency responsible for implementing all state and federal air quality laws and regulations in Louisiana, a state which is home to a very large and diverse industrial base. Ms. Higgins played a lead role in developing and implementing the Louisiana air toxics standards and program, and was the author of the Louisiana air toxics regulation. She also served as Assistant Secretary of the LDEQ Office of Environmental Services, and was responsible for final permit decision making for all permit actions taken by the Department.

Ms. Higgins' testimony in this proceeding indicates that the allowable emissions for both units in question will be far lower than those of the former Michoud Units. In addition, Ms. Higgins explains the EPA's National Ambient Air Quality Standards ("NAAQS") are designed to be protective of human health, including sensitive populations such as children and the elderly. She explains the lengthy process used by the EPA to establish those standards, and that this process included reviewing the current policy-relevant science, extensive public outreach, public comment, and a public review period. Ms. Higgins further explains that the EPA conducts a Risk/Exposure Assessment in connection with setting the standards, wherein it considers the known or likely effects and risks associated with exposure at recent or current air

quality conditions and at conditions meeting the current NAAQS and alternative NAAQS under considerations.   She also states that the state implements the NAAQS through a State Implementation Plan, which is comprised of the state laws, regulations, policies, guidelines, and programs necessary to govern air quality and specifically as needed to achieve and maintain compliance with the NAAQS across the state.   In Louisiana, the LDEQ performs this implementation role.

In this case, the LDEQ will ultimately determine whether the unit selected by the Council will be permitted, but based on Ms. Higgins' review of the facts, she fully expects for both units to comply with the EPA's standards, and that therefore human health will be protected with "an adequate margin of safety."

COMPLIANCE WITH APPLICABLE COUNCIL RULES AND ORDERS

XXXVII.

For the reasons discussed previously and in detail in the accompanying testimony, both NOPS are in the public interest, and are therefore prudent, and one should be approved by the Council.   As discussed above, either project will add capacity to the Company's generating resource portfolio that can be used in either a reserve or peaking role as necessary or appropriate, and will contribute to meeting the Company's long-term supply needs.   Moreover, either unit would support system reliability by adding necessary capacity within the supply-constrained DSG region.

REGULATORY APPROVALS

XXXVIII.

As part of this decision, the Council would approve an In-Service Cost Recovery Plan, which is discussed by Mr. Orlando Todd.   In the past, the Council has allowed timely recovery of

the costs associated with new resources obtained for the benefit of ENO's customers, such as Union Power Station Power Block 1 and the purchase power agreement ("PPA") with respect to Ninemile 6. Such rate treatment provides an incentive for ENO to continue to undertake large investments or obligations in order to secure benefits for its customers.

ENO expects to commence commercial operation in October 2019 for the Alternative Peaker; or in November 2020 if the CT is selected. At that time, the Company expects the 2018 Combined Rate Case described in Paragraph 8 of the Algiers Transaction Agreement in Principle approved in Council Resolution R-15-194, dated May 14, 2015, to be complete and all of ENO's customers to be subject to a single set of Council-approved base rates and riders. As a result of that proceeding, the Company further expects that the recovery of the capacity costs associated with the Ninemile 6 Unit and associated with Union Power Station Power Block 1 will be realigned from the Purchased Power and Capacity Acquisition Cost Recovery Rider ("PPCACR Rider") to base rates. Finally, the Company assumes that ENO will be subject to a formula rate plan ("FRP") following the Combined Rate Case. These are the principal regulatory assumptions that are the context for ENO's proposed cost recovery plan.

XXXIX.

ENO proposes that the non-fuel revenue requirement associated with either project initially be recovered contemporaneous with commercial operation of the project through the PPCACR Rider, which would be modified for such purpose, or an alternative exact cost recovery rider. This rider would use the Company's weighted-average cost of capital, including its actual capital structure, at the time the selected project commences commercial operation to determine the return on the Company's investment in the project, and the return on equity resulting from the Combined Base Rate Case. These costs would be recovered from all of the Company's

customers, including Algiers customers, which today do not pay charges pursuant to the PPCACR Rider. Assuming that the Council adopts a 2018 FRP in the Combined Base Rate Case, in the next FRP proceeding, the selected project's non-fuel revenue requirement would be realigned so as to be recovered through the FRP Rate Adjustment but outside the FRP bandwidth formula. In the FRP proceeding after that, the selected project's associated revenues and non-fuel revenue requirement would be included in the FRP bandwidth formula and recovered through the FRP Rate Adjustment.

XL.

Once the selected project commences commercial operation, ENO will begin incurring expenses related to the selected project that are not expected to be reflected in ENO's base rates at the time. If the Council takes no action to address recovery of these expenses, then those expenses will have an adverse effect on ENO's financial condition. In the event that there is no FRP in place after the Combined Rate Case, ENO proposes that the selected project's non-fuel revenue requirement be recovered through the PPCACR Rider or a similar exact cost recovery rider until such time that ENO's base rates are reset.

XLI.

As part of its requests, the Company proposes a Monitoring Plan whereby the Company would make periodic progress reports to the Advisors and the Council during the construction phase. The Monitoring Plan will serve as an "early warning system," and the Company commits to providing the Council in the quarterly reports an affirmation as to whether continuing the selected project is, in their opinion, in the public interest. The Company requests that the Council require the Advisors to acknowledge the report, in writing, and submit any questions regarding the report within 30 days. As explained in the Direct Testimony of Ms. Shauna

Lovorn-Marriage, in the original Application, if circumstances change significantly after Council approval such that the Company believes it to be in the public interest to cease construction and/or cancel the selected project, it will make a filing in this proceeding seeking Council approval of that recommendation. In this Application, the Company seeks approval of this procedure.

REQUEST FOR TIMELY TREATMENT

XLII.

The Company also requests that the Council issue the approvals requested herein no later than October 31, 2017. This procedural schedule will allow the Company to issue timely NTP to the EPC contractor selected for the Project. The Company proposes a timeline that leads to a COD date of October 2019 for the Alternative Peaker; and November 2020 for the CT. Failure to issue NTP on November 1, 2017 will result in a day-for-day slip of those expected CODs. In addition, the estimated cost to construct the Alternative Peaker assumes that the Company is able to issue NTP no later than ███████████ following receipt of acceptable approvals from the Council. The inability of the Company to issue NTP by ██████████ would cause price escalation under the EPC contract, as discussed in the Direct Testimony of Mr. Jonathan E. Long.

XLIII.

Thus, in order to facilitate an October 2017 decision, the Company proposes the following Procedural Schedule:

Discovery	Issue Date of Procedural Schedule Resolution to 15 days prior to hearing
Direct Testimony of Intervenors	August 31, 2017
Direct Testimony of Advisors	September 15, 2017
Rebuttal Testimony of ENO	September 29, 2017
Evidentiary Hearing	October 6, 2017
Hearing Officer to Certify Record	October 16, 2017
Council Decision	No later than October 31, 2017

SERVICE OF NOTICES AND PLEADINGS

XLIV.

The Company requests that notices, correspondence, and other communications concerning this Joint Application be directed to the following persons:

Gary E. Huntley
Vice President, Regulatory and
Governmental Affairs
Entergy New Orleans, Inc.
1600 Perdido Street
New Orleans, Louisiana 70112

Timothy S. Cragin
Brian L. Guillot
Alyssa Maurice-Anderson
Harry M. Barton
Entergy Services, Inc.
639 Loyola Avenue
Mailing Unit: ENT-26E
New Orleans, Louisiana 70113

REQUEST FOR CONFIDENTIAL TREATMENT

XLV.

The confidential information and documents included with the Supplemental Application marked Highly Sensitive Protected Materials or Confidential may be reviewed by appropriate representatives of the Council and its Advisors pursuant to the provisions of the Official Protective Order adopted in Council Resolution R-07-432. As such, these confidential materials shall be exempt from public disclosure, subject to the provisions of Council Resolution R-07-432.

PRAYER FOR RELIEF

XLVI.

WHEREFORE, Entergy New Orleans, Inc. respectfully requests that the Council, subject to the fullest extent of its jurisdiction, grant relief and give its approval as follows:

1. 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 prudent;

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

3. Find that the retail non-fuel revenue requirement associated with the selected NOPS (to be determined in a subsequent revenue requirement filing) project is deemed eligible for recovery in the first billing cycle of the month following commercial operation of the selected NOPS, dollar-for-dollar for at least the initial twelve-months of operation via applicable PPCACR Rider, which would be modified for such purpose, or an alternative exact cost recovery rider. Following the first twelve-months, the associated non-fuel revenue requirement shall be realigned to ENO's FRP, if applicable, or otherwise remain in the approved exact recovery rider;

4. Approve recovery, though the applicable FAC, of the energy costs and expenses incurred under the selected NOPS' LTSA, if applicable;

5. Approve the Monitoring Plan under which the Company will: (i) report to the Council Advisors on a quarterly basis the status of the selected NOPS, including

schedule, costs, and other critical associated activities, and (ii) receive written acknowledgment from the Council Advisors;

6. Rule that, with respect to the selected NOPS, the Company has complied with, or is not in conflict with, the provisions of all applicable Council Resolutions;

7. Grant a waiver of any applicable requirement to the extent that such a waiver may be required to facilitate approval of the transaction described in this Application;

8. Develop and implement appropriate procedures to facilitate a Council decision on the Application no later than October 31, 2017; and

9. Order such other general and equitable relief as to which the Company may show itself entitled.

Respectfully Submitted:

By: _____

Timothy S. Cragin, Bar No. 22313
Brian L. Guillot, Bar No. 31759
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ATTORNEYS FOR ENTERGY NEW ORLEANS, INC.

I, the undersigned counsel, hereby certify that a copy of the above and foregoing has been served on the persons listed below by facsimile, by hand delivery, by electronic mail, or by depositing a copy of same with the United States Postal Service, postage prepaid, addressed as follows:

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Council of the City of New Orleans
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

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Joshua Smith
Sierra Club Environmental Law Program
2101 Webster St., Suite 1300
Oakland, CA. 94612

Michael Brown
Waltzer, Wiygul, & Garside, LLC
1000 Behrman Hwy
Gretna, LA 70056

New Orleans, Louisiana, this 6th day of July, 2017.

_____

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

CHARLES L. RICE, JR.

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JULY 2017

TABLE OF CONTENTS

| | | **I.** | **INTRODUCTION AND PURPOSE OF TESTIMONY** |

1   **I.**   **INTRODUCTION AND PURPOSE OF TESTIMONY**

2   Q1. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

3   A.   My name is Charles L. Rice, Jr. I am President and Chief Executive Officer of Entergy

4   New Orleans, Inc. ("ENO" or the "Company"). My business address is 1600 Perdido

5   Street, Building 505, New Orleans, Louisiana 70112.

6

7   Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

8   A.   I am testifying on behalf of ENO.

9

10 Q3. ARE YOU THE SAME CHARLES L. RICE WHO FILED DIRECT TESTIMONY IN

11   THIS DOCKET ON BEHALF OF ENO?

12 A.   Yes.

13

14 Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

15 A.   My Supplemental and Amending Direct Testimony ("Supplemental Direct Testimony")

16   supports the Supplemental and Amending Application ("Supplemental Application") in

17   this proceeding, which seeks, among other things, approval to proceed with a project to

18   construct New Orleans Power Station ("NOPS"), which will consist of either a

19   combustion turbine ("CT") resource with a summer capacity of 226 megawatts ("MW"),

20   or alternatively, seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine

21   ("RICE") Generator sets ("Alternative Peaker").

22

1

1 Q5. WHY IS ENO FILING A SUPPLEMENTAL AND AMENDING APPLICATION?

2 A. In January 2017, as discussed more fully by Company witness Seth E. Cureington, the

3 Company received an updated forecast of projected customer demand for the 20 year

4 planning horizon. The updated load forecast was created by Entergy Services, Inc.

5 ("ESI")[1] for the purpose of updating the Company's financial plans, including its sales

6 forecast and financial models. ESI periodically updates its forecast of future customer

7 demand for these reasons, and the information is also used to update the EOCs' long-term

8 capacity needs and long-term transmission planning.

9 As Mr. Cureington discusses, according to the updated load forecast, the

10 Company's projections of customer demand has moderated by an average of 3.4% per

11 year (average of 40 MWs per year) compared to the forecast used in the original

12 Application. Accordingly, on February 14, 2017, after the Intervenors in this docket filed

13 their direct testimony but before the Council's Advisors filed direct testimony, the

14 Company filed a Motion to Suspend the procedural schedule in this docket in order to

15 analyze the implications of the updated forecast and to ensure that the Company takes the

16 best course of action for its customers.

17 Following the referenced Motion to Suspend, ENO has analyzed the implications

18 of the updated forecast and has concluded that the original unit proposed to the Council, a

19 226 MW CT, still has significant benefits for customers and should be constructed. The

20 Company also found, however, that the construction of a smaller unit would also create

---

[1] ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), ENO, and Entergy Texas, Inc. ("ETI").

1   significant benefits and should also be considered by the Council. Accordingly, the

2   Company now files this Supplemental Application requesting that the Council either (1)

3   approve the originally proposed CT, or (2) approve an alternative smaller resource, which

4   will be discussed throughout this filing.

5

6 Q6. HAS ENO KEPT CUSTOMERS INFORMED OF THE DEVELOPMENTS

7   DESCRIBED ABOVE?

8 A.   Yes. Since ENO filed its original Application regarding NOPS in June 2016, my staff

9   and I have endeavored to keep ENO's customers well informed regarding the Company's

10   plans to replace the Michoud units, located in New Orleans East, which were more than

11   50 years old. Throughout the course of this proceeding, I have personally attended 12

12   public community meetings throughout the City of New Orleans in an attempt to engage

13   the community about the proposed plant. Consistent with this effort, following the

14   Motion to Suspend, I sent an email to ENO customers explaining that the Company

15   requested to temporarily suspend the procedural schedule in this docket so that it could

16   evaluate the implications of the updated load forecast. In April 2017, I sent an additional

17   email updating customers about ENO's progress and its investigation into a smaller

18   alternative resource, which is now being proposed as an option for the Council's

19   consideration. That email previewed some of the benefits for customers that the

20   Alternative Peaker will offer, which are described in more detail below, and in the

21   various testimonies supporting this Supplemental Application.

22

1   Q7.   PLEASE PROVIDE AN OVERVIEW OF YOUR SUPPLEMENTAL DIRECT

2   TESTIMONY AND THE RELIEF SOUGHT BY ENO.

3   A.   My testimony begins by describing the two proposed power plant alternatives and the

4   associated benefits created by each. I explain that while ENO recommends approval of

5   the originally proposed CT, the selection of the smaller Alternative Peaker will also

6   create significant benefits for customers. I also explain that the testimonies and exhibits

7   included with this filing demonstrate that the Company has a current need for long-term

8   peaking/reserve resources, that the Company has a reliability need for local generating

9   capacity, that the project is the lowest reasonable cost alternative, considering relevant

10   risk factors, to meet those needs, and that the Company's construction of NOPS, either

11   with the CT or the Alternative Peaker, would therefore serve the public convenience and

12   necessity. I also introduce the witnesses supporting the Application and provide a

13   requested timeline for Council approvals.

14

15   **II.**   **ALTERNATIVE ONE: THE ORIGINALLY PROPOSED CT**

16   Q8.   AT THE OUTSET, PLEASE DISCUSS WHETHER THE COMPANY STILL HAS A

17   NEED FOR LOCAL GENERATION.

18   A.   As discussed by Mr. Cureington, ENO still emphatically needs a new local resource. The

19   recent deactivations of Michoud Units 2 and 3, which were economic decisions based on

20   maintenance and other operational issues, resulted in the loss of approximately 781 MW

21   of local capacity and created a need. In fact, even based on the Company's updated load

22   forecast, the Company still projects an overall need for capacity, and specifically peaking

23   and reserve capacity, over the next 20 years. As Mr. Cureington explains, the Company

1   has an overall capacity need of approximately 100 MW for the first ten years of the

2   planning horizon, which grows to 248 MW in the second ten years of the planning

3   horizon. The Company is also projected to have a peaking and reserve capacity deficit of

4   approximately 342 MW on average throughout the 20 year planning horizon.

5   Moreover, as Company witness Charles W. Long explains, the City of New

6   Orleans is located in the eastern half of the Down Stream of Gypsy ("DSG") and Amite

7   South load pockets, and is therefore very sensitive to local reliability issues. The City is

8   located in a geographical and electrical peninsula, bordered by water to the north, east,

9   and south. Accordingly, the City's ability to import power over the transmission grid is

10   limited, which makes the area highly dependent on local generation to meet customer

11   demand. This problem is amplified by the fact that a large portion of the local fleet that

12   provides reliability in the New Orleans area is aging and deactivating. As discussed more

13   fully by Mr. Cureington, many Amite South and DSG generators have recently been

14   retired, or are nearing the end of their useful lives. Given the ages of many units still in

15   operation, deactivation could happen sooner than planned. The deactivations of Michoud

16   Units 2 and 3, which together made up nearly 800 MW of generating capacity, are perfect

17   examples of this risk. Given the acute sensitivity to reliability issues that ENO's service

18   territory faces, it is prudent for the Company to begin planning for these retirements,

19   which will be decisions based on the condition of the particular units at issue and made

20   independently of any decision to add generation.

21   In addition, the Company has conducted a transmission analysis that indicates that

22   if a plant is not built at the Michoud facility, ENO's system may not remain reliable

23   throughout the planning horizon absent costly transmission upgrades.   In fact, if

1   incremental generation is not added, and costly transmission upgrades are not performed,

2   the Company's service territory will face the risk of cascading (or uncontrolled) outages

3   under certain scenarios that would affect most of the New Orleans area. Figure 1 depicts

4   the areas that would be affected by the referenced outages:

5   **Figure 1**
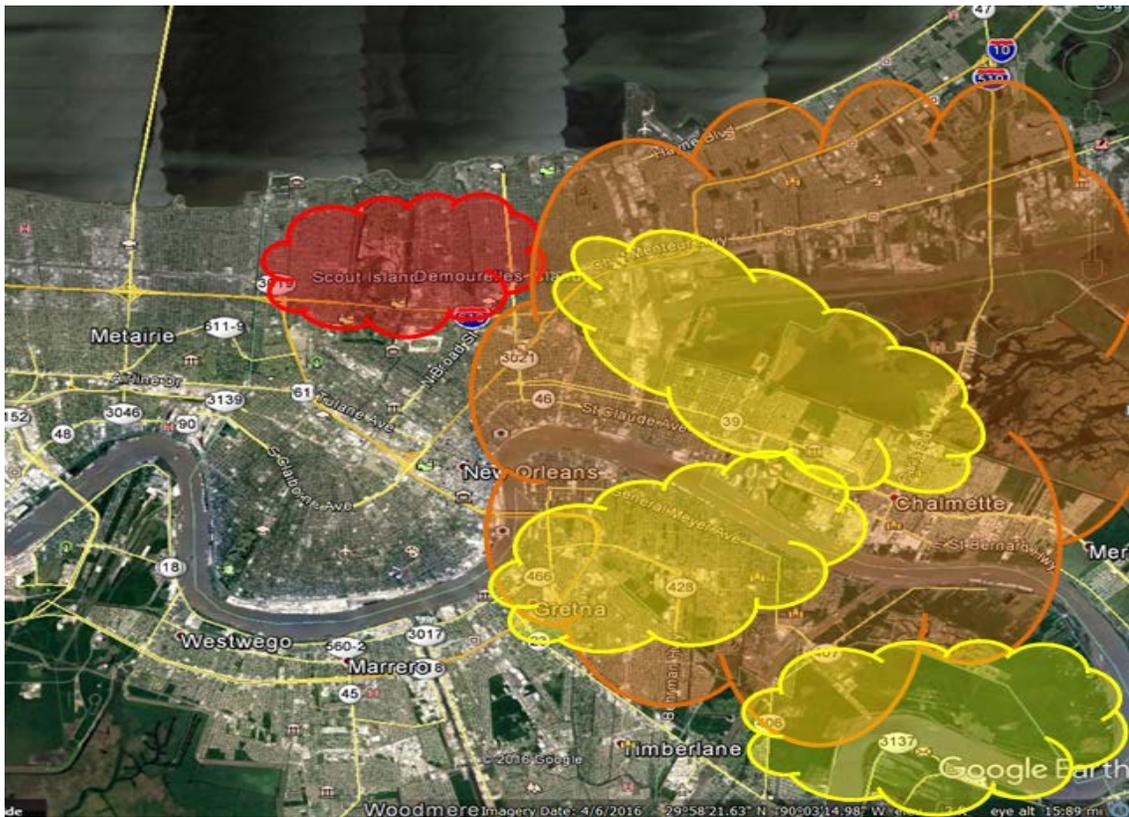
6

7   As noted by Mr. Charles Long, adding either the originally proposed CT or the

8   Alternative Peaker, which will be discussed below, will mitigate the potential for these

9   outages. A local unit will also assist in storm restoration and in the event the City of New

10   Orleans becomes islanded, meaning that the transmission lines importing power into the

11   city are severed, as they were in Hurricane Gustav. This important benefit of adding local

12   generation cannot be overstated and is consistent with the Council's stated objective to

1   harden the system in preparation for major weather events. In summary, a local unit (*i.e.*,

2   the CT or the Alternative Peaker) is still very much needed and the Company is

3   committed to its construction in order to provide substantial benefits for customers.

4

5   Q9.   DOES THE COMPANY STILL RECOMMEND APPROVAL OF THE ORIGINALLY

6   PROPOSED CT?

7   A.   Yes. In June 2016, the Company proposed a natural-gas-fueled CT generating facility

8   with a nominal capacity of approximately 226 MW, at summer conditions. Simply put,

9   that CT remains the best option for customers. As mentioned, the Company has an

10   overall capacity need that grows to approximately 248 MW, and a peaking need of 342

11   MW on average throughout the 20 year planning horizon. The CT would substantially

12   address these long-term needs.

13   Moreover, as Mr. Cureington also discusses, the modeling used to estimate the

14   Total Relevant Supply Costs of various portfolios, including those requested by the

15   Council's Advisors, produced results that were consistent with ENO's original

16   Application in that the CT is the most cost-effective means of addressing the Company's

17   identified long-term planning needs when using the Company's assumptions around

18   capacity prices in Midcontinent Independent System Operator, Inc. ("MISO"). Even

19   under a sensitivity using highly discounted capacity price assumptions, the CT is virtually

20   tied with other portfolios and should therefore prevail given its significant local benefits.

21   It is also important to note that when comparing the CT to the Alternative

22   Peaker, there are some benefits created by the addition of local generation that increase as

23   the size of the local generator increases and which give the CT a slight advantage over

1   the Alternative Peaker because of its 100 MW size advantage. These benefits include the

2   following:

3   -   For reliability purposes, the DSG load pocket is in need of generating capacity

4   to fill the void that will be created by retirements in the aging fleet of local

5   resources. This need favors the addition of more generating capacity, not less.

6   -   The 226 MW CT would eliminate all North American Electric Reliability

7   Corporation ("NERC") reliability issues throughout the 10-year planning

8   horizon, including the cascading outages discussed above and all other

9   reliability issues identified for smaller units in the Company's reliability

10   analysis.

11   -   As discussed more fully by Mr. Cureington, the larger CT would create a more

12   effective hedge against market and supply related risks in MISO caused by

13   ENO's generation being located outside of the New Orleans Load Zone.

14   -   The larger CT would create larger reliability margins over and above the

15   minimum amount of generation needed for grid stability.

16   -   The larger CT would create more reactive power, more flexibility to take

17   outages, and less dependence on the transmission system than would a smaller

18   unit.

19   For these reasons, and for the additional reasons provided in this Supplemental and

20   Amending Application, the 226 MW CT remains the best option for customers. In light

21   of the recently updated load forecast, however, the Alternative Peaker, as discussed more

22   fully below, will also provide benefits for ENO customers and should be considered a

23   viable alternative to the originally proposed CT.

1

2 Q10.   WHAT IS THE CURRENT COST ESTIMATE AND PROJECTED COMMERCIAL

3   OPERATION DATE FOR THE CT?

4 A.   The Council should be aware that the current cost estimate for the CT has increased by

5          $16 million, as discussed by Mr. Jonathan Long, bringing the overall cost estimate to

6   approximately $232 million. The new anticipated Commercial Operation Date ("COD"),

7   provided regulatory approval is received by the end of October 2017 and Notice to

8   Proceed ("NTP") is granted to the engineering, procurement, and construction ("EPC")

9   contractor by November 1, 2017, is approximately November 2020.

10

11   **III.   ALTERNATIVE TWO: RICE GENERATOR SETS**

12 Q11.   PLEASE DESCRIBE THE ALTERNATIVE PEAKER BEING PROPOSED BY THE

13   COMPANY.

14 A.   As explained by Mr. Jonathan Long, the Company engaged WorleyParsons, a qualified

15   engineering firm, to conduct a study regarding the Company's potential options for a

16   smaller resource. The analysis indicated that RICE technology was the best option to

17   meet ENO's needs. As Mr. Jonathan Long explains, RICE is a well-known technology

18   used in automobiles, trucks, marine propulsion, and backup power applications. RICE

19   technology uses the expansion of hot gases to push a piston within a cylinder, converting

20   the linear movement of the piston into the rotating movement of a crankshaft to generate

21   power. In a power plant, multiple spark-ignited or diesel RICE engines are grouped into

22   blocks of engines, called generating sets, to provide modular electric generating capacity

1   in standardized sizes.   Please see Figure 2 for an example of an engine hall consisting of

2   RICE engines:

3   **Figure 2**

4

5   Based on the study conducted by WorleyParsons, as described by Mr. Jonathan Long, the

6   RICE units had the lowest levelized cost of electricity on a $/MWh basis compared to the

7   alternatives considered, as well as other benefits such as low water usage, a low

8   emissions profile, the ability to support renewable resources, and the inclusion of black-

9   start capability.

10

1   Q12.   IS THE ALTERNATIVE PEAKER PROPOSED TO BE LOCATED AT THE SAME

2   SITE AS THE ORIGINALLY PROPOSED CT?

3   A.   Yes. The Alternative Peaker is proposed to be located at the Michoud facility in New

4   Orleans, Louisiana.   Figure 3 illustrates the exact location of the Alternative Peaker:

5   **Figure 3**

6

1

2　Q13.　WHAT IS THE CURRENT COST ESTIMATE AND PROJECTED COMMERCIAL

3　　　　OPERATION DATE FOR THE ALTERNATIVE PEAKER?

4　A.　The current cost estimate for the Alternative Peaker is $210 million. The anticipated

5　　　　COD, provided regulatory approval is received by the end of October 2017 and NTP is

6　　　　granted to the EPC contractor by November 1, 2017, is expected in October 2019.

7

8　Q14.　PLEASE ELABORATE ON THE BENEFITS ASSOCIATED WITH THE

9　　　　ALTERNATIVE PEAKER.

10　A.　As discussed more fully by Mr. Jonathan Long, the RICE units have a heat rate that is

11　　　　significantly lower than the retired Michoud units' heat rates and also lower than the

12　　　　proposed CT's. A unit's heat rate refers to the fuel required to generate a unit of

13　　　　electricity. Thus, the lower a plant's heat rate, the less fuel is required to generate

14　　　　electricity and the more efficient the unit. In general, this is a benefit to customers since

15　　　　fuel is a pass-through cost.

16　　　　　The Alternative Peaker also utilizes a very low amount of water. As discussed by

17　　　　Mr. Jonathan Long, the RICE engines will use water to cool the engines due to

18　　　　evaporation in the generation process and for other uses at the site. The RICE engines,

19　　　　however, will use much less ground water than the retired Michoud units and the

20　　　　originally proposed CT.

21　　　　　The technology is also a great choice to back-up renewable generation. As this

22　　　　Council is well aware, ENO has committed to adding up to 100 MW of renewable

23　　　　resources to its generation portfolio, and the details of ENO's plans are provided below.

1   As discussed in the testimonies of Messrs. Seth E. Cureington and Charles Long,

2   however, renewable resources cannot meet a peaking capacity need because they are

3   intermittent and not dispatchable, meaning they cannot produce power when the sun isn't

4   shining or the wind isn't blowing and the Company cannot ramp up production when

5   needed to meet demand. In order to address this problem, many utilities around the

6   country have added RICE units to their portfolios because these units are able to start and

7   achieve full load in a very short period of time, start and stop multiple times in a single

8   day, and maintain emissions profiles over a range of operating outputs.

9   In addition, the unit will also include black-start capability, which will enable the

10   Company to start the unit even when there is no power on the electric grid. This will give

11   the Company the ability to restore electric service, should a complete loss of service

12   occur. This could be a tremendous benefit if New Orleans is electrically "islanded" from

13   the rest of the interconnected transmission grid, as it was after Hurricane Gustav.

14

15   Q15.   ARE THERE ADDITIONAL BENEFITS ASSOCIATED WITH THE ALTERNATIVE

16   PEAKER?

17   A.   Yes. As mentioned above, the Alternative Peaker will provide many of the same benefits

18   as the larger CT, albeit to a lesser degree. To recap, the Alternative Peaker will add

19   generation in DSG to fill the void that will be created as units in the aging generation

20   fleet inevitably retire on their own merits, provide a hedge against market and supply

21   related risks in MISO caused by ENO's generation being located outside of the New

22   Orleans Load Zone, add generation to increase the flexibility to take outages to maintain

23   transmission lines and generators, add reactive power, and lessen dependence on the

1   transmission system to meet customer demand. The Alternative Peaker will also provide

2   valuable storm restoration support and would have the ability to serve load in the city in

3   an emergency situation.

4   Another benefit of the Alternative Peaker, as discussed by Mr. Charles Long, is

5   that the unit would also address the possibility of cascading, uncontrolled outages under

6   certain contingencies, as discussed above.   In fact, if the Alternative Peaker is

7   constructed, there would only be very minor overloading on the transmission system in

8   planning year 2027.   Under this circumstance, the Company would propose to wait until

9   a point-in-time that is closer to the needed upgrades to determine if they are still

10   necessary.   Thus, the Alternative Peaker could potentially also satisfy all NERC

11   reliability criteria.

12   Also, as Mr. Cureington discusses, the Company modeled the Total Relevant

13   Supply Costs of various portfolios, including those requested by the Council's Advisors.

14   Under every scenario, including under sensitivities around lower than projected capacity

15   prices in MISO, the Alternative Peaker was competitive with other portfolios that were

16   modeled. Specifically, while the Alternative Peaker was not the lowest cost alternative,

17   its total supply cost ranged from .04% lower to 3.99% higher than the "transmission-

18   only" and "100 MW Solar" cases that were modeled (this result was across the entire

19   range of assumptions and sensitivities).   Thus, as explained by Mr. Cureington, this

20   result is a virtual tie, and based on ENO's need for a local resource, the Alternative

21   Peaker should prevail over the transmission only and solar portfolios given its ability to

22   address local reliability concerns and satisfy a portion of ENO's need for peaking

23   generation.

1

2   Q16.   WILL THE COMPANY USE A THIRD-PARTY EPC CONTRACTOR FOR THE

3   PROJECT?

4   A.   Yes.   The Company has selected Burns and McDonnell ("B&M") to provide EPC

5   services for the Alternative Peaker as a result of a procurement process discussed by Mr.

6   Jonathan Long. B&M was selected through this process because of competitive pricing

7   and prior experience with constructing units using RICE technology. By 2015, B&M had

8   installed a total of 72 RICE engines, with 60 of these being Wärtsilä engines. B&M has

9   constructed a total of 16 power generation facilities utilizing RICE technology. One of

10   these projects is a 12 engine Wärtsilä plant at the Denton Energy Center in Denton,

11   Texas, which employs the same engines that will be installed at NOPS. The Southwest

12   Texas Electric Cooperative's Pearsall plant is yet another plant constructed by B&M that

13   is similar to the Alternative Peaker.

14

15   Q17.   IS THE PROJECT EXPECTED TO PROVIDE BENEFITS IN ADDITION TO THE

16   PLANNING BENEFITS DISCUSSED IN THE TESTIMONIES OF MESSRS.

17   CUREINGTON AND CHARLES LONG?

18   A.   Yes. In June 2016, Loren C. Scott & Associates, Inc. studied the effect that construction

19   of the CT is expected to have on the economies of the State of Louisiana and Orleans

20   Parish. That study concluded that the construction and operation of the CT will produce

21   significant economic benefits – totaling hundreds of millions of dollars – in terms of new

22   business sales, household earnings, and jobs in both the State and regional economies.

23   Benefits result not only from one-time capital expenditures, but also from ongoing

1   operational expenditures that will continue to accrue to the benefit of residents in the

2   region and State as long as the CT is in operation. The Company has engaged Loren C.

3   Scott & Associates, Inc. to perform an analysis of the impacts of the Alternative Peaker,

4   but its economic impact is expected to be similar to the CT's.

5

6   Q18.   WHY IS THE COST ESTIMATE OF THE ALTERNATIVE PEAKER SIMILAR TO

7   THE ESTIMATE PROVIDED FOR THE CT?

8   A.   As previously stated, the larger CT comes with economies of scale given its larger size,

9   and the relationship that the Company has maintained with its manufacturer (Mitsubishi

10   Hitachi Power Systems America, Inc. ("MHPSA")) and EPC contractor (Chicago Bridge

11   & Iron, Inc. ("CB&I")). It should be noted that the EOCs have selected the same CT, the

12   G-Frame, for use in multiple power plants across the Entergy fleet, including NOPS and

13   three additional 2x1 combined-cycle gas turbine ("CCGTs") being proposed in other

14   service territories. Moreover, CB&I has been selected to construct these CCGTs.

15   Accordingly, the relatively similar pricing between the CT and the smaller Alternative

16   Peaker reflects more on the economies of scale that the Company has leveraged by

17   proposing to purchase seven G-Frame turbines and using the same EPC contractor to

18   construct each unit, than it does on the cost of the RICE units, which will employ a

19   different technology and use a different EPC contractor. It should also be noted however,

20   that although the Alternative Peaker costs more than the CT on a $/kW basis, as

21   discussed more fully above, the Alternative Peaker has valuable benefits such as black-

22   start capability, a lower heat-rate, and lower water usage.

1   **IV.   ENVIRONMENTAL FACTORS**

2   Q19.   HAS ENO STUDIED THE POTENTIAL ENVIRONMENTAL IMPACTS OF THE CT

3   AND THE ALTERNATIVE PEAKER?

4   A.   Yes. I would like to first take this opportunity to state that the Company has operated

5   power plants at its Michoud Facility for over 50 years and the recent deactivations of

6   Michoud Units 2 and 3 resulted in the loss of approximately 781 MW of local generation.

7   Put simply, it was never a long-term solution to not fill the void left by the retirement of

8   those units, as some Intervenors in this docket have suggested. Following the prudent

9   decision to deactivate Michoud Units 2 and 3 based on their conditions, the Company has

10   worked to execute on its plan to replace that generation with a newer, more efficient unit,

11   since one is absolutely needed for long-term reliability. The Company originally

12   proposed the CT, which had lower emissions and much lower groundwater usage than the

13   retired Michoud Units. To further support its application, the Company has hired well-

14   respected experts in the fields of air emissions and geology who have concluded that the

15   emissions from the proposed CT are reasonable, based on standards developed by the

16   Environmental Protection Agency ("EPA"), and that groundwater usage will be minimal

17   and not cause subsidence and/or property damage.

18   In selecting the Alternative Peaker, the Company considered the fact that it will

19   also have emissions that meet EPA standards and will use a negligible amount of

20   groundwater that also, like the CT, will not cause subsidence or property damage. The

21   Company has done its best to communicate these findings to the community at large

22   throughout the pendency of its Application in this docket, and will continue to do so

23   throughout this supplemental phase.

1

2   Q20.   HAS ENO STUDIED THE POTENTIAL IMPACT OF GROUNDWATER USAGE

3   FOR BOTH THE CT AND THE ALTERNATIVE PEAKER?

4   A.   Yes.   The Company engaged Dr. George Losonsky, Ph.D., P.G., a geologist who

5   formerly served as a Commissioner of the Southeast Louisiana Flood Protection

6   Authority-East, to study the issue of groundwater usage for both plants. Dr. Losonsky

7   conducted various analyses and concluded that the groundwater withdrawal associated

8   with the CT and Alternative Peaker will not cause incremental subsidence or cause

9   damage to infrastructure in New Orleans East. Dr. Losonsky conducted site-specific

10   calculations to predict a maximum drawdown over a 10-year period, and concluded that

11   the proposed groundwater withdrawal/drawdown rates for the plants in question will be

12   too small to directly affect subsidence or cause damage to buildings and infrastructure at

13   the Michoud site or in New Orleans East.

14

15 Q21.   HAS ENO STUDIED THE EMISSIONS IMPACT OF THE PROPOSED UNITS?

16 A.   Yes. The Company engaged Bliss M. Higgins, who has had a distinguished career at the

17   Louisiana Department of Environmental Quality ("LDEQ"), the agency responsible for

18   implementing all state and federal air quality laws and regulations in Louisiana, a state

19   which is home to a very large and diverse industrial base. Ms. Higgins played a lead role

20   in developing and implementing the Louisiana air toxics standards and program and was

21   the author of the Louisiana air toxics regulation. She also served as Assistant Secretary

22   of the LDEQ Office of Environmental Services, and was responsible for final permit

23   decision making for all permit actions taken by the Department.

18

1   Ms. Higgins' testimony in this proceeding indicates that the allowable emissions

2   for both units in question will be far lower than those for the retired Michoud Units.   In

3   addition, Ms. Higgins explains that the EPA's National Ambient Air Quality Standards

4   ("NAAQS") standards are designed to be protective of human health including sensitive

5   populations, such as children and the elderly. She explains the lengthy process used by

6   the EPA to establish those standards, and that this process included a review of the

7   current policy-relevant science, extensive public outreach, public comment, and a public

8   review period.   Ms. Higgins further explains that the EPA conducts a Risk/Exposure

9   Assessment in connection with setting the standards, wherein it considers the known or

10   likely effects and risks associated with exposure at recent or current air quality conditions

11   and at conditions meeting the current NAAQS and alternative NAAQS under

12   considerations.   She also states that the state implements the NAAQS through a State

13   Implementation Plan ("SIP"), which is composed of the state laws, regulations, policies,

14   guidelines, and programs necessary to govern air quality and achieve and maintain

15   compliance with the NAAQS across the state. In Louisiana, the LDEQ performs this

16   implementation role.

17   In this case, the LDEQ will ultimately determine whether the unit selected by the

18   Council will be permitted, but based on Ms. Higgins's review of the facts, she fully

19   expects both units to comply with the EPA's standards, and that therefore human health

20   will be protected with "an adequate margin of safety."

1   **V.**   **ENO'S 100 MW RENEWABLE COMMITMENT**

2   Q22.   ENO'S SUPPLEMENTAL APPLICATION AND SUPPORTING TESTIMONY

3   INDICATE THAT COUNCIL APPROVAL OF NOPS WILL HELP SUPPORT THE

4   ADDITION OF RENEWABLES TO ENO'S RESOURCE PORTFOLIO. DOES ENO

5   HAVE ANY PLANS TO ADD RENEWABLES TO ITS RESOURCE PORTFOLIO?

6   A.   Yes. ENO has committed to adding renewable resources to its portfolio and believes that

7   doing so will benefit customers, including but not limited to adding environmentally

8   clean resources that also provide fuel diversity and a hedge against natural gas exposure.

9   I have previously committed on behalf of ENO to pursue up to 100 MW of renewable

10   resources and I renew that commitment here.

11

12   Q23.   HAS ENO TAKEN ANY CONCRETE ACTION TOWARDS FULFILLING THAT

13   COMMITMENT?

14   A.   Yes. ENO recently conducted and concluded a formal Request for Proposals ("RFP")

15   seeking proposals for up to 20 MW of renewable resources. The RFP was conducted

16   under the supervision of an independent monitor. After receiving and reviewing several

17   bids, in May 2017, ENO announced that it had selected three RFP proposals for

18   negotiation of definitive agreements, totaling approximately 45 MW, over twice the

19   original amount sought in the RFP. Of the proposals selected, one is for the acquisition

20   of an approximately 20 MW solar resource to be located in Orleans Parish, the second is

21   for an approximately 5 MW solar self-build rooftop project also to be located in Orleans

1   Parish, and the third involves a 20 MW long-term power purchase agreement from a solar

2   resource to be located near Lafayette, Louisiana.

3

4   Q24.   WHAT IS THE CURRENT STATUS OF THE PROJECTS SELECTED FROM THE

5   RFP?

6   A.   The Company is in the process of negotiating contracts with the third-party bidders and

7   firming up other arrangements necessary to allow ENO to prepare an Application (or

8   Applications, if the projects are to be considered separately) with supporting testimony

9   and exhibits to submit to the Council seeking approval to add these projects to ENO's

10   resource portfolio.   The contract negotiation process can take several months and is

11   subject to numerous variables that can affect the outcome and timing for completion of

12   negotiations. At this early stage in the process, ENO is tentatively targeting submission of

13   its approval filing (or filings) sometime in the first quarter of 2018.

14

15   Q25.   YOU MENTIONED A COMMITMENT TO SEEK UP TO 100 MW OF RENEWABLE

16   RESOURCES.   DOES THE COMPANY HAVE ANY PLANS WITH REGARDS TO

17   FULFILLING THE REMAINDER OF THAT COMMITMENT?

18   A.   The Company is currently exploring available avenues for fulfilling the remainder of its

19   100 MW commitment.

20

1   Q26.   FROM TIME TO TIME, SOME REPRESENTATIVES OF INTERVENORS HAVE

2   SUGGESTED THAT ENO IS OPPOSED TO RENEWABLES. ARE YOU OR ENO

3   OPPOSED TO ADDING RENEWABLES?

4   A.   Absolutely not. The Company would like to add renewables to its portfolio and it is

5   taking the actions necessary to do just that. The Company prefers to add renewables to

6   its portfolio in a responsible manner for customers and all stakeholders ensuring grid

7   reliability and considering risks.

8

9   **VI.   COUNCIL APPROVALS AND TIMELINE**

10   Q27.   WHEN DOES ENO REQUEST THE COUNCIL GRANT THE NECESSARY

11   REGULATORY APPROVALS?

12   A.   ENO asks that the Council take the steps needed to establish a Procedural Schedule such

13   that the Council would issue a decision no later than October 31, 2017. This time table

14   will provide adequate time for the Council, its Advisors and any stakeholders to review

15   and provide comment on the Supplemental Application, while also permitting ENO to

16   commence construction in time to achieve its target substantial completion date. In order

17   to facilitate a October 2017 decision, the Company proposes the following Procedural

18   Schedule:

Discovery	Issue Date of Procedural Schedule Resolution to 15 days prior to hearing
Direct Testimony of Intervenors	August 31, 2017
Direct Testimony of Advisors	September 15, 2017
Rebuttal Testimony of ENO	September 29, 2017
Evidentiary Hearing	October 6, 2017
Hearing Officer to Certify Record	October 16, 2017
Council Decision	No later than October 31, 2017

19

1   **VII.   INTRODUCTION OF WITNESSES**

2   Q28.   PLEASE INTRODUCE THE WITNESSES WHO HAVE FILED SUPPLEMENTAL

3   AND AMENDING DIRECT TESTIMONY ON BEHALF OF ENO AND IDENTIFY

4   THE SUBJECTS THAT EACH ADDRESSES.

5   A.   In addition to my testimony, ENO's Supplemental Application is supported by the

6   testimony of the following witnesses:

7   •   **Seth E. Cureington** – Mr. Cureington is the Director, Resource Planning and

8   Market Operations for ENO.   Mr. Cureington discusses the circumstances

9   surrounding the updated load forecast referenced in ENO's February 14, 2017

10   Motion to Suspend, and how the Company is still in need of long-term capacity,

11   and in particular peaking and reserve capacity.   He explains why local generation

12   is needed, and the results of modeling conducted on behalf of the Company and

13   the Council's Advisors.

14 •   **Jonathan E. Long** – Mr. Jonathan Long is the Vice President, Capital Projects

15   for ESI.   He provides an overview of the updated cost estimate and timeline for

16   the CT.   He also provides an overview of the Alternative Peaker, the

17   management approach that the Company intends to employ, and the EPC

18   contractor selected for the Alternative Peaker.

19 •   **Charles W. Long** – Mr. Charles Long is the Director of Transmission Planning

20   for ESI.   He describes, from the transmission perspective, the unique

21   characteristics of the DSG region and how the construction of either the CT or

22   Alternative Peaker will have the effect of avoiding/delaying projects that would

23   otherwise be necessary to maintain reliability.   Mr. Long also describes the

1   transmission related reliability benefits associated with constructing the CT and

2   Alternative Peaker.

3   • **Bliss M. Higgins** – As described above, Ms. Higgins is an expert in air emissions

4   and permitting and has concluded that the CT and the Alternative Peaker will

5   have allowable emissions significantly below those of the former Michoud Plant

6   and that these facilities emissions will comply with the U.S. Environmental

7   Protection Agency ("EPA") National Ambient Air Quality Standards, which

8   were established to be protective of human health, including sensitive

9   populations, with an adequate margin of safety via a lengthy EPA process with

10   extensive and scientific community public involvement.

11   • **Dr. George Losonsky, Ph.D., P.G.,** – As described above Dr. Losonsky is an

12   expert geologist and former Commissioner of the Southeast Louisiana Flood

13   Protection Authority-East.   Dr. Losonsky conducted various analyses and

14   concluded that the groundwater withdrawal associated with the CT and

15   Alternative Peaker will not cause incremental subsidence or cause damage to

16   infrastructure in New Orleans East.

17   • **Orlando Todd** – Mr. Todd is the Finance Director for ENO. Mr. Todd provides

18   the estimated first-year revenue requirement associated with the Project. He also

19   describes the proposal to recover the costs associated with the Alternative Peaker

20   and the importance of timely recovery.

21   • **Robert A. Breedlove** – Mr. Breedlove is the Director of Plant Support in Fossil

22   Operations.   Mr. Breedlove provides the estimated operation and maintenance

1   costs for the Alternative Peaker.

2

3   **VIII.   CONCLUSION**

4   Q29.   PLEASE SUMMARIZE YOUR SUPPLEMENTAL DIRECT TESTIMONY.

5   A.   ENO is requesting the Council's timely consideration of its Supplemental Application for

6   approval to construct NOPS, which will consist of either a CT resource with a summer

7   capacity of 226 MW, or alternatively, the Alternative Peaker with a capacity rating of

8   approximately 128 MW. Both the CT and the Alternative Peaker have significant

9   benefits, as described in this Supplemental Application and supporting testimonies.

10   Either plant will improve supply conditions in the Company's service area by providing a

11   long-term resource capable of supporting reliable service to New Orleans during periods

12   of peak demand and unplanned events, and either will mitigate market- and supply-

13   related risks. As stated above, either plant will have the effect of eliminating the risk of

14   cascading outages in New Orleans and the ability to provide reliability benefits such as

15   support for restoration efforts following major weather events. The environmental

16   allegations that have been levied against the proposed units are not accurate, as discussed

17   by the Company's technical reports and expert testimony in this proceeding. In short, the

18   testimonies and exhibits included with this filing support the approval of either the CT or

19   the Alternative Peaker by this Council.

20

21   Q30.   DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

22   A.   Yes.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **CHARLES L. RICE, JR.,** who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.
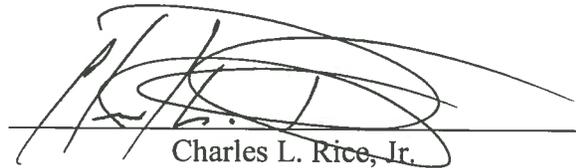
_____
Charles L. Rice, Jr.

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 27th DAY OF JUNE, 2017 ,
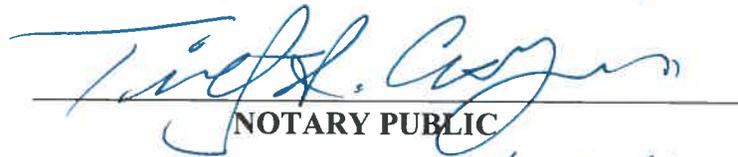
_____
NOTARY PUBLIC

My commission expires: _at death_

TIMOTHY S. CRAGIN
NOTARY PUBLIC (La. Bar No. 22313)
Parish of Orleans, State of Louisiana
My Commission is issued for Life

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

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

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

SETH E. CUREINGTON

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

Entergy New Orleans, Inc.
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JULY 2017

TABLE OF CONTENTS

EXHIBIT LIST

1   **I. INTRODUCTION**

2   Q1.   PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

3   A.   My name is Seth E. Cureington. My business address is 1600 Perdido Street, New

4   Orleans, Louisiana 70112.

5

6   Q2.   ARE YOU THE SAME SETH E. CUREINGTON WHO FILED DIRECT TESTIMONY

7   (JUNE 2016) AND SUPPLEMENTAL DIRECT TESTIMONY (NOVEMBER 2016) IN

8   THIS DOCKET?

9   A.   Yes.

10

11   Q3.   ON WHOSE BEHALF ARE YOU TESTIFYING?

12   A.   I am testifying before the Council of the City of New Orleans ("CNO" or the "Council")

13   on behalf of Entergy New Orleans, Inc. ("ENO" or the "Company").

14

15   **II. PURPOSE OF TESTIMONY**

16   Q4.   WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL AND AMENDING DIRECT

17   TESTIMONY?

18   A.   My Supplemental and Amending Direct Testimony ("Supplemental Direct Testimony")

19   supports the Supplemental and Amending Application ("Supplemental Application") in

20   this proceeding, which seeks, among other things, approval to construct the New Orleans

21   Power Station ("NOPS"), which will consist of either a combustion turbine ("CT")

22   resource with a summer capacity of 226 megawatts ("MW"), or alternatively, seven

1   Wärtsilä 18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator sets

2   ("Alternative Peaker").   My testimony proceeds as follows:

3   • I first explain the circumstances surrounding the updated load forecast referenced

4   in ENO's February 14, 2017 Motion to Suspend, and I explain how the Company

5   is still in need of long-term capacity, and in particular peaking and reserve

6   capacity.   I also explain that renewable resources, demand-side management

7   ("DSM") programs, and/or reliance on the short-term Midcontinent Independent

8   System Operator, Inc. ("MISO") capacity market are not viable alternatives to the

9   construction of either the original CT or the Alternative Peaker.

10   • Second, I explain how having a generating resource in the Company's service

11   area (*i.e*., Orleans Parish) can help to mitigate market and supply related risks,

12   which would benefit customers.

13   • Next, I describe the results of the Company's updated AURORAxmp Electric

14   Market Model ("AURORA") modeling, which takes into account the updated

15   load forecast mentioned above, to model the CT, the Alternative Peaker, and a

16   "transmission only" approach (which ENO does not consider a viable option for

17   meeting the identified needs).

18   • I then summarize the Council Advisors' Recommendations,[1] which at the behest

19   of certain Intervenors who are opposed to NOPS, requested ENO to perform

---

[1]   Advisors' Recommendations with Respect to ENO's New Orleans Power Station Supplemental Filing, Docket No. UD-16-02 ("Advisors' Recommendations") (March 23, 2017).

1   AURORA modeling and analyses using different assumptions (the "Requested

2   Portfolios"). I also provide the results of these analyses.

3   • Finally, I explain why the assumptions referenced above in the Requested

4   Portfolios are not reasonable, citing to a new, independent examination of the

5   achievable Energy Efficiency ("EE") potential in ENO's service territory,

6   explaining why modeling capacity prices in the manner proposed by Intervenors

7   opposed to NOPS is arbitrary, and explaining why renewable resources are not

8   reasonable alternatives to dispatchable resources for meeting the Company's

9   peaking and reserve needs.

10

11   Q5.   PLEASE SUMMARIZE THE CONCLUSIONS REACHED IN YOUR TESTIMONY.

12   A.   As mentioned above, and as discussed more fully below, my testimony explains that

13   ENO's most recent load forecast (Highly Sensitive Protected Materials ("HSPM")

14   Exhibit SEC-10)[2] has moderated by an average of 3.4% per year (average of 40 MW per

15   year) compared to the forecast used in the original Application. Accordingly, I include

16   an updated Load and Capability ("L&C") analysis based on the revised forecast as HSPM

17   Exhibit SEC-11, which indicates that the Company continues to have an overall need for

18   long-term capacity, including a substantial need for peaking and reserve capacity.

19   My testimony also discusses the modeling used to estimate the Total Relevant

20   Supply Cost for three Reference Cases (sometimes referred to as "Reference Portfolios").

---

[2]   The details regarding how DSM programs and customer-owned distributed energy resources are
incorporated into the forecast are included in my workpapers.

1   Specifically, ENO modeled a portfolio that included the originally proposed CT (since

2   that option is still before the Council), another with the Alternative Peaker, and a third

3   that included incremental transmission upgrades necessary to mitigate North American

4   Electric Reliability Corporation ("NERC") violations but no long-term peaking resource

5   addition.   In addition, based on requests by certain Intervenors opposed to NOPS, the

6   Council's Advisors requested that ENO model certain other portfolios incorporating

7   different assumptions, including what is likely an unrealistic assumption of DSM

8   program implementation.   Specifically, the Recommendations requested that ENO

9   determine a least-cost portfolio using AURORA based on an assumed implementation of

10   the Council's DSM goal,[3] and to the extent the least-cost portfolio included the

11   Alternative Peaker, to develop a second least-cost portfolio without the Alternative

12   Peaker. To comply with that request, the Company modeled four portfolios with the

13   following incremental resource additions: (1) the Alternative Peaker, (2) the 226 MW

14   CT, (3) 100 MW of additional solar (for a total of 200 MW of solar), and (4) 300 MW of

15   wind resources.

16   Table 1 provides a summary of the Total Relevant Supply Cost results for both

17   the Reference Cases and Requested Portfolios using ENO's projected MISO capacity

18   prices and a reference gas price forecast.

19

---

[3]   *See* Advisors' Recommendations at p. 1, n.2.

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1 **Table 1**

2

3
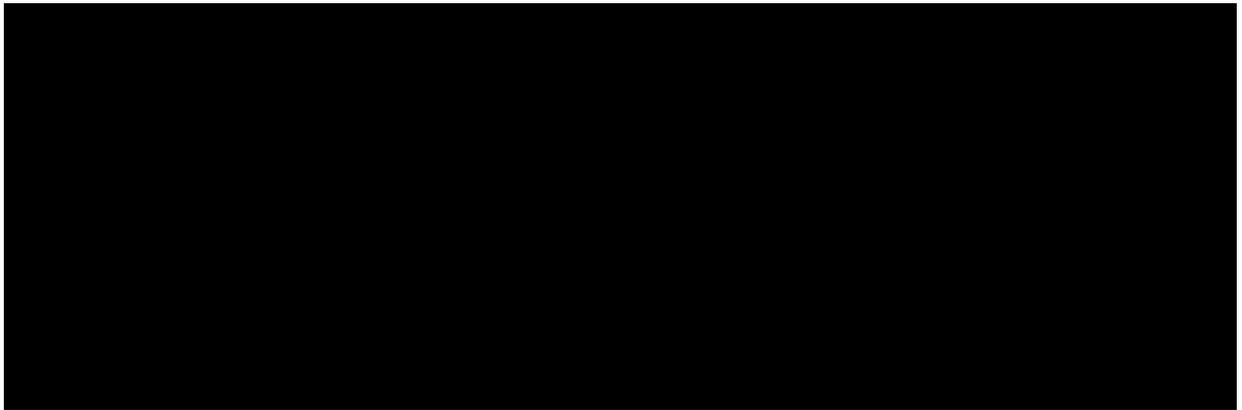
4
5

6   The results shown in Table 1 are consistent with ENO's original Application in that the

7   CT is the most cost-effective means of addressing the Company's identified long-term

8   planning needs while considering risk. Moreover, as explained below, although the

9   portfolios that include the Alternative Peaker are ranked below the CT portfolios, the

10   Alternative Peaker is a reasonable alternative to the CT. It should be noted at the outset,

11   however, that portfolios that involve building transmission alone and/or adding

12   renewable capacity are not viable planning alternatives to building a local, dispatchable

13   peaking resource.

14

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   **III.   UPDATED LOAD FORECAST AND IMPLICATIONS**

2   Q6.   PLEASE DESCRIBE THE CIRCUMSTANCES THAT PROMPTED ENO TO FILE A

3   REQUEST TO SUSPEND THE PROCEDURAL SCHEDULE IN THIS CASE.

4   A.   On February 14, 2017, after the Intervenors filed their Direct Testimony,[4] but before the

5   Council's Advisors filed their Direct Testimony, the Company filed a Motion to Suspend

6   the procedural schedule in order to analyze the implications of an updated load forecast

7   developed by Entergy Services, Inc. ("ESI"),[5] a service company to the EOCs, for

8   purposes of updating the Company's financial plans, including the sales forecast and

9   financial models. ESI periodically updates its forecast of future customer demand for

10   these reasons, and the information is also used to update the EOCs' long-term capacity

11   needs and long-term transmission planning. As discussed more fully by Company

12   witness Charles Rice, once ENO reviewed the results of the updated load forecast and

13   determined that there could be implications to this proceeding (*i.e.*, that the Company's

14   forecast of peak demand had moderated), it requested to suspend the proceeding in order

15   to evaluate the best course of action for its customers.

16

---

[4]   It should be noted that while the Company disagrees with most of the arguments put forward by the Intervenors
in their Direct Testimony, the Company will reserve its right to address each argument advanced by the Intervenors
in rebuttal. To the extent that the Advisors' Recommendations, referenced above, are based on recommendations
made by the Intervenors' Direct Testimony, however, I will, in some cases, point out why those suggested
assumptions are unreasonable and should not be relied upon for prudent long-term resource planning.

[5]   ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning,
accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy
Arkansas, Inc. ("EAI"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), Entergy New Orleans,
Inc., and Entergy Texas, Inc. ("ETI").

1   Q7.   WHAT IS THE EFFECT OF THE FORECASTED CHANGE IN PEAK LOAD?

2   A.   The Company's original Application was based on the then-current peak load forecast,

3   which was included in my HSPM Exhibit SEC-4. Based on that load forecast, and the

4   Company's existing long-term supply and demand-side resources, the Company

5   projected an overall need for approximately 134 MW of capacity by 2020, and up to 205

6   MW by 2030. That forecast projected a peaking and reserve deficit of 377 MW in 2020,

7   growing to 383 MW in 2030.

8   Under the updated load forecast, the Company continues to have an overall need

9   for additional long-term capacity, including a substantial need for peaking and reserve

10   capacity.   As shown in Table 2, the Company now projects an overall need for

11   approximately 99 MW of capacity by 2026, growing to 248 MW by 2036. The Company

12   also has a persistent peaking and reserve deficit of approximately 342 MW on average in

13   each year of the 20-year planning horizon. Table 2 provides an updated summary of the

14   Company's projected capacity position:

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1

Table 2

(MW)[6]	2026			2036		
	Need	**Resources**	**Surplus/ (Deficit)**	**Need**	**Resources**	**Surplus/ (Deficit)**
Base Load	536	455	(81)	552	406	(146)
Load Following	308	628	320	317	569	252
Peaking & Reserve	426	88	(338)	438	84	(354)
Total	1,270	1,171	(99)	1,307	1,059	(248)

2

3   Q8.   AS A GENERAL MATTER, IS IT NORMAL TO EXPECT CHANGES IN LOAD

4   FORECASTS OVER TIME?

5   A.   Yes. Forecasts are subject to uncertainty; however, the Company relies on industry-

6   standard tools and techniques to reduce that uncertainty to the extent possible. The

7   Company estimates peak demand, but ultimately must be prepared to serve whatever

8   level of load materializes, when it materializes.

9

10 Q9.   WHAT CAUSED THE CHANGES FROM ENO'S PRIOR LOAD FORECAST TO

11   THE UPDATED FORECAST DESCRIBED HEREIN?

12 A.   The decline in the Company's projected peak load was driven primarily by a decline in

13   projected sales among the residential and commercial customer classes. Actual weather

14   normalized sales in 2016 were approximately 2.1% lower than 2015 due primarily to a

15   decline in residential and commercial usage per customer ("UPC"). While the Company

16   continues to experience growth in the total number of customers served, the decline in

---

6   Figures may not foot as compared to Exhibit SEC-11 due to rounding.

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   UPC more than offset that growth in 2016. Despite a small reduction in sales versus the

2   prior load forecast, projected Industrial class peaks increased slightly due to the projected

3   shift forward in the Company's peak load when compared to the prior forecast. Projected

4   Governmental class sales and peak load is forecasted to be lower when compared to the

5   prior forecast primarily due to delays and modifications associated with the new Veterans

6   Affairs hospital project. The impact of the decline in UPC in 2016 among the residential

7   and commercial classes explains approximately 90% of the change in the Company's

8   current forecast of peak load when compared to the prior forecast.

9

10   Q10.   DUE TO THE INHERENT UNCERTAINTY IN ANY FORECAST, IS IT POSSIBLE

11   THAT THE UPDATED LOAD FORECAST COULD BE UNDERSTATED?

12   A.   Yes. The load forecast is based on a "confidence interval" that captures 95% of the

13   potential load outcomes. While this means that there is a statistical possibility that actual

14   load could be lower than forecast, there is an equal statistical risk that actual load could

15   be higher than forecast, which would subject customers to the price risks of the short-

16   term capacity market and reliability risks if ENO has planned only for the forecasted load

17   and, as a result, lacks sufficient long-term resources to serve the actual load.

18

19   Q11.   ARE THERE OTHER CIRCUMSTANCES THAT COULD INCREASE ENO'S NEED

20   FOR GENERATING CAPACITY?

21   A.   Yes. I explained in my Direct Testimony that several of the existing legacy units

22   included in the Company's portfolio are approaching the end of their useful lives and are

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   subject to deactivation earlier than expected.[7] Table 3 below identifies the approximately

2   60 MW of allocated capacity associated with legacy units scheduled for deactivation

3   within the planning horizon. If even a portion of this capacity is deactivated sooner than

4   scheduled, the Company's resource needs would increase sooner than forecasted, further

5   exposing ENO's customers to market and supply-related risks, including short-term

6   capacity market prices that are expected to increase as equilibrium approaches.

7

Table 3

Algiers PPA Unit	In-Service	Age In 2017	ENO Allocated MW
Little Gypsy 2	1966	51	7.6
Little Gypsy 3	1969	48	9.5
Buras	1971	46	0.2
Ninemile 4	1971	46	12.4
Ninemile 5	1973	44	14.0
Sterlington 7A	1974	43	0.9
Waterford 1	1975	42	7.5
Waterford 2	1975	42	7.6
Total Allocated Capacity			59.7

8

9   Q12. IS THERE SIMILAR RISK WITH THE COMPANY'S COAL RESOURCES?

10   A.   Yes. The Company's portfolio currently includes approximately 33 MW of coal-fired

11   generating capacity originating from long-term power purchase agreements with EAI for

12   the White Bluff and Independence generating facilities. The planning assumptions

13   reflected in HSPM Exhibit SEC-11 include that Independence Unit 1 remains active

14   through the planning horizon. White Bluff Units 1 and 2 are assumed to deactivate by

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[7]   *See* Cureington Direct at 22.

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   ███, if not sooner, based on EAI's current assumption that the White Bluff units will be

2   allowed to continue operating without having to add expensive emissions control

3   technology. However, if such control technology is required for continued operations,

4   operation of the White Bluff units may no longer be economic and could be deactivated

5   sooner than assumed. Similar to the risk I describe above regarding the aging legacy gas-

6   fired fleet, if the White Bluff units deactivate sooner than planned, the Company's

7   resource needs would grow more quickly than forecasted, further exposing ENO's

8   customers to market and supply-related risks.

9

10   Q13.   WHAT HAS THE COMPANY CONCLUDED WITH RESPECT TO ITS LONG-TERM

11   RESOURCE NEEDS IN LIGHT OF THE UPDATED LOAD FORECAST?

12   A.   Even based on the Company's updated load forecast, it still has a need that would support

13   the construction of the CT proposed in this docket. The Company's planning principles

14   outlined in my Direct Testimony support a balanced approach to resource planning that

15   considers both cost and risk to customers in the provision of safe and reliable electric

16   service. To that end, ENO's analysis is based on a forecast of demand for the next 20

17   years, and while ENO is projected to have an overall capacity need of approximately 100

18   MW for the first ten years of the planning horizon, that need is projected to more than

19   double in the second ten years of the planning horizon. As stated, ENO is projected to

1   have an overall capacity need of approximately 248 MW, the majority of which could be

2   addressed by the CT.[8]

3   Although ENO prefers to add long-term resources that would most cost-

4   effectively meet the resource needs identified over the planning horizon, the Council

5   could alternatively approve construction of a smaller resource now and defer the

6   projected need to obtain additional long-term capacity until a later date. Accordingly, the

7   Company has proposed a smaller Alternative Peaker that would meet a portion of ENO's

8   long-term capacity needs and mitigate exposure to market and supply related risks, while

9   still adding generation in a strategic location of the electric grid that would produce

10   reliability benefits and avoid the costly transmission upgrades discussed more fully by

11   Company witness Charles W. Long. Thus, should the Council approve the Alternative

12   Peaker, it would address the overall capacity need identified in the first half of the

13   planning horizon, in which case ENO would continue to evaluate alternatives to fill the

14   unmet resource needs projected for the second half of the planning horizon.

15

---

[8] The identified need assumes replacement capacity upon the assumed deactivation of Union Power Station
Power Block 1 in 2033. I make the simplifying assumption in HSPM Exhibit SEC-11 to include the capacity
associated with Union Power Station Power Block 1 through the remainder of the planning horizon.

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1 Q14. TABLE 1 SHOWS A SUBSTANTIAL NEED FOR PEAKING AND RESERVE

2   CAPACITY DESPITE THE MODERATION IN LOAD SHOWN IN THE UPDATED

3   FORECAST. WILL THE TECHNOLOGY SELECTED FOR THE ALTERNATIVE

4   PEAKER HELP TO ADDRESS THAT NEED EVEN THOUGH IT DOES NOT

5   EMPLOY CT TECHNOLOGY?

6 A.   Yes. HSPM Exhibit SEC-11 indicates that ENO will have a peaking and reserve capacity

7   deficit in 2017 of approximately 332 MW, which deficit is expected to persist throughout

8   the twenty-year planning horizon. As more fully discussed by Company witness

9   Jonathan E. Long, the units that would comprise the Alternative Peaker are able to start

10   and achieve full load in a very short period of time, and start and stop multiple times in a

11   single day. Both of these characteristics are critical during periods of peak demand and

12   unplanned events like generation or transmission outages because the proposed units can

13   supply electricity almost simultaneously with customer demand. Thus, the Alternative

14   Peaker would improve supply conditions in the Company's service area by providing a

15   long-term resource capable of supporting reliable service to New Orleans during periods

16   of peak demand and unplanned events, and it would mitigate market and supply related

17   risks.

18

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1 Q15. ENO HAS CONTINUOUSLY EMPHASIZED THE IMPORTANCE OF MEETING ITS

2 NEED FOR PEAKING CAPACITY. IS IT COMMON PRACTICE FOR UTILITIES

3 TO DEPLOY PEAKING RESOURCES?

4 A. Yes. Prudent resource planning considers not only overall capacity needs, but also the

5 need for capacity to serve specific supply roles, such as base load, load following,

6 peaking, and reserve. Having an appropriate amount of capacity suitable to serve each of

7 these supply roles allows the Company to reliably and cost-effectively serve the time-

8 varying level of customer load. Supply role requirements are considered as general

9 guidelines for portfolio planning purposes and do not necessarily address other planning

10 criteria (*e.g*., locational considerations). The Company's peaking requirement is defined

11 as the level of load that is served in the highest 15% of the hours of the year. Finally, a

12 planning reserve target also helps to maintain reliable service over a range of planned and

13 unplanned circumstances.

14 Each supply resource has its own unique cost and performance characteristics that

15 allow it to be functionally and economically suited to serve a given supply role. This is

16 generally true for all load-serving entities. In order to reliably meet customers' needs at

17 the lowest reasonable cost, the Company must maintain a portfolio of long-term

18 resources that includes the appropriate amounts and types of capacity. At this time, the

19 Company has a need for long-term resources, including resources capable of operating in

20 a peaking and reserve role. Table 4 provides a non-exhaustive, illustrative list of the

21 amount of peaking resources owned by several major utilities.

22
23 **Table 4**

Utility	CT/Peaking Resources	Total MW
Georgia Power	32	1,000+
Florida Power & Light	9	1,000+
LADWP	12	1,000+
San Diego Gas & Electric	24	750
Alabama Power	10	750
Southern California-Edison	5	245
Mississippi Power	3	226

1

2 Q16. DOES THE COMPANY CONTINUE TO BELIEVE THAT DSM, RENEWABLE

3   RESOURCES, AND THE MISO CAPACITY MARKET ARE NOT REASONABLE

4   ALTERNATIVES FOR ADDRESSING THE IDENTIFIED LONG-TERM PEAKING

5   AND RESERVE CAPACITY NEEDS?

6 A.   Yes. Although there are benefits associated with renewable resource alternatives, such as

7   hedging exposure to volatility in the price of natural gas, the intermittent nature of

8   renewable resources limits the Company's ability to rely on them to meet peak demand.

9   Thus, should the Company need to call on such resources to ramp up production when

10   customer demand peaks or an unplanned event occurs, those resources would not provide

11   that dispatch capability.

12   Moreover, because renewable resources receive a lower capacity credit in MISO,

13   the Company cannot count a megawatt of renewable resource capacity equal to a

14   megawatt of gas-fired generation in planning to meet its long-term capacity needs. So

15   even if those intermittent resources could meet the Company's long-term need for

16   peaking and reserve capacity (which they cannot), the Company would need to acquire

17   significantly more capacity than its need dictates due to the lower capacity credit. This

18   means that while renewable resources have significant benefits (ENO is currently taking

1   measures to add up to 100 MW of solar to its portfolio), many utilities, as discussed by

2   Mr. Jonathan Long, have found that intermittent resources need to be backed up by

3   traditional resources, and the Alternative Peaker is an ideal resource to function in such a

4   role.

5   Regarding DSM resources, insufficient cost-effective incremental DSM programs

6   are available beyond the Company's currently-approved Energy Smart programs to meet

7   the entirety of the Company's long-term needs. During the 2015 IRP process, the

8   Company engaged ICF International ("ICF") to conduct an analysis of the long-term

9   DSM potential achievable in New Orleans. Based on the results of ICF's study, the

10   achievable amount of DSM in New Orleans constitutes only approximately 14% of

11   ENO's projected need for long-term peaking and reserve capacity by 2019 (leaving a

12   remaining deficit of 290 MW). As discussed more fully bellow, the Company recently

13   engaged a second independent consultant, Navigant Consulting, Inc. ("Navigant"), to

14   perform an additional analysis to determine the maximum achievable amount of EE

15   potential savings over a 20-year planning horizon. Using its own methodology and

16   leveraging relevant measures from the stakeholder-informed Arkansas Energy Efficiency

17   Potential Study that it prepared for the Arkansas Public Service Commission in 2015,

18   Navigant concluded that, under an aggressive scenario, ENO could potentially reduce

19   forecast sales by roughly 17% over the next 20 years, which averages to 0.85%/year.[9]

20   As discussed more fully in my Direct Testimony, reliance on the MISO capacity

21   market to meet long-term resource needs is also not a viable nor prudent alternative.

---

[9] The Navigant Report is attached as Exhibit SEC-14. The year by year incremental savings are shown in Table 1.

1   ENO's planning assumption is that market equilibrium (where supply, including third

2   party resources, and demand balance) in MISO South will occur around 2022. As market

3   equilibrium approaches, capacity prices will reflect new build prices, which are

4   significantly higher than today's capacity prices.   Deferring construction of a new

5   resource comes with considerable risk given the long lead time necessary to gain

6   regulatory approvals, obtain necessary permits, and plan and construct new resources.

7   There is also risk around both the potential cost premiums for parts and equipment as

8   other utilities seek to build modern, gas-fired resources, and the sharply higher and more

9   volatile capacity prices expected as the capacity market approaches equilibrium.

10   Moreover, as discussed more fully below, reliance on the MISO capacity market will not

11   mitigate the local reliability considerations that are addressed by adding local generation

12   in Orleans Parish.   Accordingly, continued reliance on MISO's capacity market

13   constitutes a risky gamble, and as discussed more fully below, would expose ENO's

14   customers to congestion risk in the energy market as well.

15

16   **IV. THE IMPORTANCE OF LOCAL PEAKING CAPACITY**

17   Q17. PLEASE   BRIEFLY   SUMMARIZE   THE   COMPANY'S   NEED   FOR   LOCAL

18   GENERATION.

19   A.   As discussed in detail in my original Direct Testimony, and in the Direct Testimony of

20   Charles W. Long, ENO's service area is located inside the Down Stream of Gypsy

21   ("DSG") and Amite South load pockets.   These regions are heavily dependent on a

22   limited amount of local generators to ensure reliability and to meet customer demand

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   because of geographic limitations on transmission import capability. As a result, the

2   Company must now take steps to add new resources as the existing generation fleet that

3   maintains reliability in DSG and Amite South ages and units continue to deactivate. This

4   point is illustrated by the recent retirements of ENO's Michoud Units 2 and 3, which

5   together made up nearly 800 MW of generating capacity. Moreover, ELL's recent

6   decision to retire Little Gypsy Unit 1 and Ninemile Unit 3 is also instructive. These

7   decisions, like all deactivation decisions, were made independently (*i.e.*, not tied to any

8   other investment decisions) based on unit condition and the economics of each respective

9   unit, but it is simply a reality that as legacy units grow older and continue to deactivate, a

10   void will be created that needs to be proactively addressed.

11   For example, some of the remaining legacy units located in Amite South and DSG

12   are currently committed during a significant number of hours throughout the year in order

13   to meet MISO's commitment rules in these load pockets. The legacy units, however, are

14   all over 40 years old, nearing the end of their useful lives, and are less efficient than

15   either the CT or the Alternative Peaker. The planned deactivations of those units are also

16   assumed to occur during the planning horizon and could occur sooner than expected

17   given the age of these units.[10]

18   The point here is that legacy generation in the Amite South and DSG load pockets

19   will not operate in perpetuity and should not be over-relied upon in maintaining reliable

20   and economic service. This means that to meet the reliability needs of New Orleans,

21   which has a concentrated load squarely within the DSG load pocket and no

---

[10]   Namely, Little Gypsy Units 2 (414 MW) (1966) and 3 (517 MW) (1969), Ninemile Units 4 (699 MW) (1971) and 5 (721 MW) (1973), and Buras (12 MW) (1971).

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   corresponding generation within the Company's service area, incremental generation

2   needs to be added.

3   Failure to add incremental generation inside the Company's service area will

4   exacerbate reliance on an already heavily-loaded transmission system to import

5   electricity to serve load, which will increase risks to customers associated with, among

6   other things, maintaining reliable service at the lowest reasonable cost, storm restoration,

7   transmission upgrade costs, increased transmission and generation maintenance cost,

8   outage frequency, and the flexibility to schedule transmission and generation outages.

9   The need to balance the reliance on transmission with in-region generation in developing

10   long-term resource plans was illustrated when transmission lines used to serve Amite

11   South and DSG load were severed by Hurricane Gustav, leaving the City of New Orleans

12   "islanded" from the rest of the interconnected transmission grid and, thus, completely

13   reliant on aging in-region generation at a critical time to customers.

14

15   Q18. HAS ELL TAKEN STEPS TO ADDRESS THE AGING LEGACY GENERATION IN

16   THE DSG AND AMITE SOUTH REGIONS?

17   A.   Yes. ELL, a utility that also serves load in these regions, has begun the process of

18   building new generation to ensure reliability for its customers. This is evidenced by

19   ELL's plan to build a 980 MW combined-cycle gas turbine ("CCGT") in Montz,

20   Louisiana, which will be called the St. Charles Power Station ("SCPS"). The current cost

21   estimate for that facility is approximately $870 million. In fact, my understanding is that

22   in the Louisiana Public Service Commission ("LPSC") docket related to SCPS, several

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   intervenors in that case advanced the argument that LPSC-jurisdictional customers should

2   not be obligated to pay the full costs of the plant because it will have reliability benefits

3   for ENO, which currently has a limited amount of local generation, and accordingly does

4   not ensure its own reliability. But contrary to those intervenors' statements, ENO and the

5   Council are committed to doing their part to add local generation to address reliability.

6   As previously discussed in ENO's original Application, the Council has already

7   ordered ENO in Resolution R-15-524, to "use reasonable diligent efforts to pursue the

8   development of at least 120 MW of new-build peaking generation capacity within the

9   City of New Orleans."[11] That Resolution also emphasizes a commitment for ENO "to use

10   diligent efforts to have at least one future generation facility located in the City of New

11   Orleans."[12] NOPS, if approved, would comply with each of these directives from the

12   Council. R-15-524 also directed ENO to "fully evaluate Michoud or Paterson, along with

13   any other appropriate sites in the City of New Orleans, as the potential site for a CT or

14   other peaking unit to be owned by ENO."[13] The construction of NOPS at the Michoud

15   site, as discussed in my Direct Testimony, complies with that portion of the directive as

16   well and adds incremental generating capacity in the City of New Orleans, as directed by

17   the Council.

18

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[11]   *See* R-15-524 at 12.

[12]   *Id*.

[13]   *Id*.

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   Q19.   WILL AN IN-REGION RESOURCE LIKE NOPS MITIGATE MARKET AND

2   SUPPLY RELATED RISKS?

3   A.   Yes. The Company no longer has a source of generating capacity inside its service area

4   that can respond to planned and unplanned events, which increases customers' exposure

5   to Locational Marginal Prices ("LMP") in the MISO wholesale energy market. In MISO,

6   load serving entities purchase all of the energy necessary to serve their load from the

7   MISO market at the LMP for the zone within which the load is situated ("Load Zone

8   LMP"). Generators are paid the LMP at their location for any energy produced

9   ("Generator LMP"). Because the New Orleans Load Zone is situated squarely within the

10   DSG load pocket, the New Orleans Load Zone LMP tends to be higher than Load Zone

11   LMPs that are not located in a load pocket due to congestion on the transmission system

12   relied upon to serve load in DSG. This situation can be exacerbated during unplanned

13   outages of a transmission line or a generator that can lead to significant increases in

14   congestion, which puts upward pressure on the New Orleans Load Zone LMP.

15   In ENO's case, because all of its generation is located outside of the New Orleans

16   Load Zone, its customers' exposure to increases in the New Orleans Load Zone LMP is

17   only partially mitigated by the revenues received for its remote generation, which are

18   generally lower than ENO's payment obligations. While Auction Revenue Rights and

19   Financial Transmission Rights ("ARR" and "FTR") can provide an effective hedge

20   against congestion between the Company's remote generation resources and the New

21   Orleans Load Zone LMP, a local source of generation inside the load zone is necessary to

22   help mitigate congestion risk during unplanned events such as the forced outage of an

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   existing source of generation.   For example, if an event (planned or unplanned) occurred

2   that caused New Orleans Load Zone LMPs to sharply increase, a local source of

3   generation inside the load zone that MISO could dispatch would provide a source of

4   revenues ($/MWh) that would be priced substantially the same as the New Orleans Load

5   Zone LMP.

6

7   Q20. IS THERE EVIDENCE FROM THE COMPANY'S REAL-TIME OPERATIONS

8   THAT INDICATES THAT AN ADDITIONAL PEAKING AND RESERVE

9   CAPACITY RESOURCE IS NEEDED UNDER NORMAL OPERATING

10   CONDITIONS?

11   A.   Yes. Looking at the Company's real-time generation compared to load for the Summer

12   months of June 1 – August 31, 2016, ENO was short the necessary generation at various

13   times throughout that period, leading to unhedged market purchases of energy

14   approximately ▇▇▇ of the time. Moreover, the Company's largest hourly purchase of

15   energy was over ▇▇▇ MW. Having NOPS in the Company's portfolio would provide a

16   hedge against real-time shortages in generation that expose customers to the Load Zone

17   LMP. Figure 1 below illustrates the timing and duration of the Company's real-time

18   short position last summer.

1

Figure 1

6   Q21.   COULD LOCAL GENERATION MITIGATE RISK ASSOCIATED WITH MEETING

7   THE LOCAL CLEARING REQUIREMENT FOR LOCAL RESOURCE ZONE 9?

8   A.   Yes. The MISO capacity market includes ten Local Resource Zones ("LRZs"). For each

9   LRZ, there is a minimum and maximum amount of capacity located in the zone that may

10   clear the capacity auction. These zonal constraints can lead to different prices in different

11   LRZs. For example, generally if there is a surplus of capacity in a zone, then the price in

12   that zone may be lower than in neighboring zones, and if there is a scarcity of capacity in

13   a zone, then the price there may be higher than the price in neighboring zones. The

14   import and export limits for each zone are also important factors in the determination of

15   zonal constraints that can lead to price separation between LRZs.

1   Capacity market settlements are zonal – loads are charged the auction clearing

2   price for the LRZ in which they are located, and generators are paid the auction clearing

3   price for the LRZ in which they are located. This creates the potential for price

4   separation, which is a risk for load serving entities ("LSEs") that do not own or contract

5   for enough generating capacity located in the same zone as their load. With

6   approximately ▮% of its capacity located outside of LRZ 9, ENO is such an LSE, and in

7   the event of price separation, ENO's capacity resources outside of LRZ 9 may be paid

8   less than ENO's load is charged. Price separation between LRZ 9 and LRZ 8 and 10 has

9   not occurred in the first four capacity auctions that included MISO South. However,

10   because the capacity import limit for LRZ 9 is significantly less than the planning reserve

11   margin requirement set by MISO, there exists a risk of price separation between LRZ 9

12   and LRZ 8 and 10 that could be triggered by changes in the amount of capacity resources

13   located in LRZ 9 and a corresponding increase in the need to import capacity. The

14   addition of NOPS would mitigate customers' exposure to the risk of price separation by

15   providing an additional source of capacity in LRZ 9.

16

17 Q22. WHAT OTHER BENEFITS ARE ASSOCIATED WITH THE ADDITION OF A NEW

18   AND MODERN SOURCE OF GENERATION IN THE LOAD POCKET?

19 A.   Historically, the legacy generating units located in the Amite South and DSG load

20   pockets have been dispatched throughout the year to maintain reliability of the bulk

21   electric grid in the region. Within DSG, the units at ELL's Ninemile generating facility

22   provide the only source of local generation to serve in this role. Throughout the year,

1   MISO commits the units at Ninemile to maintain reliability in DSG, and while the new

2   Ninemile Unit 6 is a highly efficient combined-cycle generating unit, the legacy Ninemile

3   4 and 5 units are approximately 45 years old and are less efficient than the CT or

4   Alternative Peaker. When the Ninemile units are committed by MISO for reliability

5   (referred to by MISO as "Voltage and Local Reliability" or "VLR"), ENO's customers

6   share in the variable cost to operate those units. Once NOPS is in service, it will provide

7   an additional, more efficient source of generation to support reliability in DSG and is

8   expected to displace some amount of generation currently provided by Ninemile 4 and 5,

9   lowering costs for ENO's customers.

10

11   Q23.   DOES   A   LOCAL   RESOURCE   PROVIDE   BENEFITS   DURING   STORM

12   RESTORATION OR IN RESPONSE TO SIGNIFICANT UNPLANNED OUTAGES?

13   A.   Yes.   Having additional local generation will reduce the Company's reliance on

14   transmission assets that are likely to be out of service immediately following a significant

15   unplanned outage or weather event (*e.g*., hurricanes). For example, as mentioned above,

16   Hurricane Gustav severed all of the transmission lines serving the region, including the

17   Company's service area, which left the area "islanded," or separated from the rest of the

18   interconnected transmission grid. In an islanded situation, the Company is completely

19   reliant on local generation, which currently means generation outside of Orleans Parish.

20   If the generators located outside of Orleans Parish or the transmission lines that import

21   power to New Orleans are in a forced outage, then the City would be completely without

22   power. Having a local unit in New Orleans mitigates that risk. Moreover, as discussed

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
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1   by Mr. Charles Long, the Alternative Peaker has black-start capability, meaning that it

2   can start and operate without transmission support and could be critical to supplying

3   power within the City as well as assisting in restoring the electric grid.

4

5   **V.   SUPPLEMENTAL TOTAL SUPPLY COST ANALYSES**

6   Q24. PLEASE DESCRIBE THE ROLE OF PRODUCTION COST MODELING IN

7   RESOURCE   PLANNING   AND   EVALUATING   SPECIFIC   RESOURCE

8   ALTERNATIVES.

9   A.   Once a resource need is established, as it has been for ENO, and one or more resources

10   are identified as potential alternatives capable of meeting that resource need, production

11   cost modeling and simulations are used to assess the variable supply cost effects of

12   adding a particular resource or set of resources to a utility's resource portfolio. These

13   variable supply cost effects can then be used as inputs into a broader economic analysis,

14   in which spreadsheet models are used to layer on projected capacity costs, non-fuel

15   operating costs, and revenues in order to determine the Total Relevant Supply Cost

16   associated with the addition of a specific resource or set of resources to the utility's

17   portfolio.

18

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

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1   **A.**   **The Company's Reference Cases**

2   Q25.   PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S UPDATED AURORA

3   MODELING RUNS.

4   A.   The Company conducted AURORA[14] production cost modeling on each of three

5   Reference Cases across sensitivities for natural gas and MISO capacity prices. As shown

6   in HSPM Exhibit SEC-12, the first Reference Case (labeled "ENO Case 1" in the tables

7   and exhibits) evaluates the addition of the Alternative Peaker. The second Reference

8   Case (labeled "ENO Case 1G" in the tables and exhibits) evaluates the addition of the

9   originally proposed 226 MW G-frame CT. The third Reference Case (labeled "ENO

10   Case 2" in the tables and exhibits) evaluates the scenario in which no peaking resource is

11   added, *i.e.*, a "transmission-only" scenario. The scenarios requested by the Council's

12   Advisors at the behest of Intervenors opposed to NOPS will be discussed below.

13

14   Q26.   WHAT COMMON ASSUMPTIONS WERE UTILIZED IN THE COMPANY'S

15   REFERENCE CASES?

16   A.   Uniform assumptions adopted in each of the ENO Reference Cases are presented in

17   HSPM Exhibit SEC-12 and include the Business Plan 17 Update ("BP17U") forecast of

18   load and commodity prices including reference CO_2, the planned addition by ENO of up

19   to 100 MW of solar resources, the continuation of the Energy Smart program, and full

20   deployment of Advanced Metering Infrastructure. Sensitivity analyses were conducted

---

[14]   *See* Cureington November 2016 Supplemental Direct at 4-5 for further explanation of the AURORA production cost model.

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
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1   for each portfolio using low and high case natural gas price forecasts as well as a

2   sensitivity using 60% of the Company's MISO capacity price forecast.[15]

3

4   Q27. WHAT WERE THE RESULTING TOTAL RELEVANT SUPPLY COSTS OF THE

5   COMPANY'S REFERENCE CASES?

6   A.   The resulting model outputs for each portfolio were incorporated into the Total Relevant

7   Supply Cost analysis, which is attached as HSPM Exhibit SEC-13. The results based on

8   the reference, low and high gas price forecasts are summarized in Figure 2 below:

9   **Figure 2**
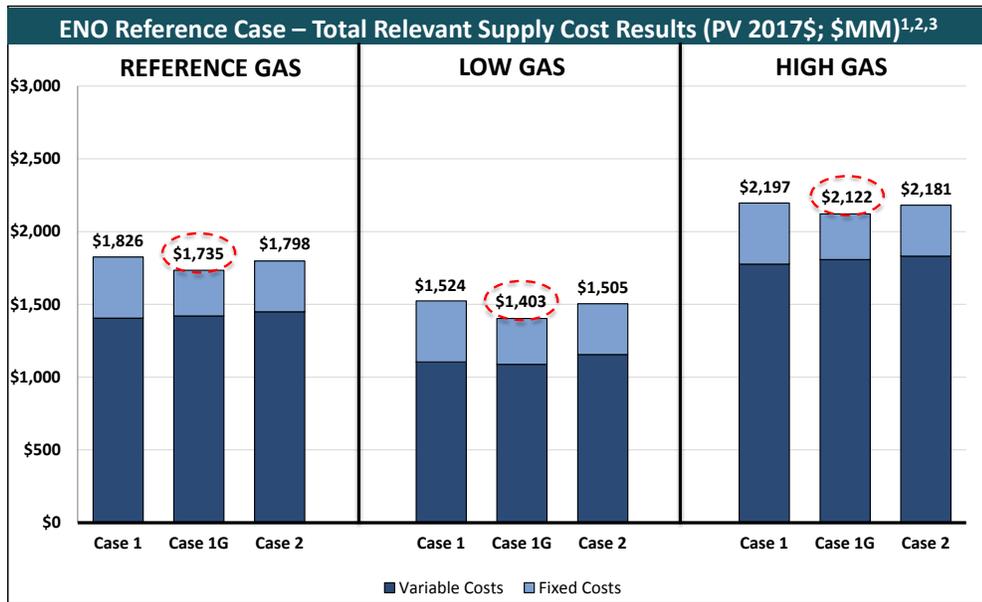
Notes:
1. The Fixed Cost component is the sum of DSM costs, Incremental Resource costs, Transmission costs and Capacity Purchases/(Sales).
2. The Capacity Purchases/(Sales) are based on the MISO South Capacity Price Curve as of May 2016.
3. The 20 year evaluation period of this analysis is (2017 – 2036).

10

11

---

[15]   *See* Advisors' Recommendations at 3.

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
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1 Q28. WHAT WERE THE RESULTS OF THE COMPANY'S REFERENCE CASES UNDER

2   THE REQUESTED CAPACITY PRICE SENSITIVITY?

3 A. Figure 3 below summarizes the results of the Company's Reference Cases using both

4   high and low gas prices as well as projected MISO capacity prices that are 60% of the

5   Company's Reference Case MISO capacity price assumptions.

6   **Figure 3**
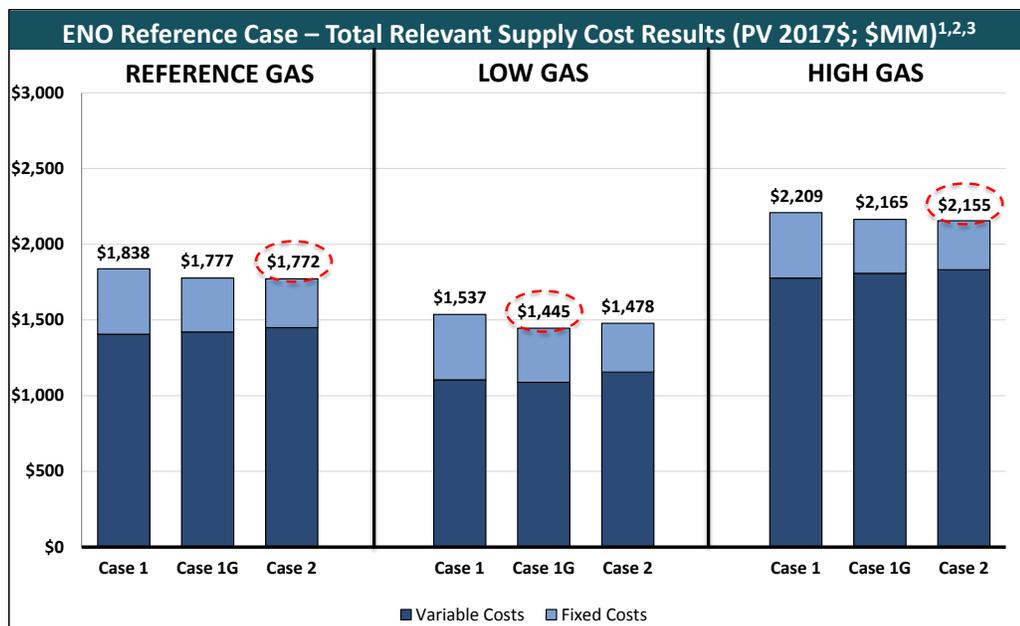
Notes:
1. The Fixed Cost component is the sum of DSM costs, Incremental Resource costs, Transmission costs and Capacity Purchases/(Sales).
2. The Capacity Purchases/(Sales) are based on the MISO South Capacity Price Curve as of May 2016 **at 60% of CONE**.
3. The 20 year evaluation period of this analysis is (2017 – 2036).

9 Q29. DO YOU HAVE ANY COMMENTS ON THE TRANSMISSION-ONLY SCENARIO?

10 A. Yes. I believe that this scenario (ENO Case 2) understates the Total Relevant Supply

11   Costs because it is essentially a "do-nothing" approach in which transmission upgrades

12   are made solely to maintain NERC reliability requirements. It does not address the

13   additional resources required to meet the identified needs of ENO's customers, and it

1   does not address the market and supply related risks I discuss above. It also does not

2   address the risk to customers associated with undue exposure to the short-term market

3   price for capacity in MISO, which is expected to approach equilibrium. Thus, Case 2 is

4   not a viable alternative for meeting ENO's long-term resources needs but rather reflects a

5   gamble that equilibrium is not on the horizon, capacity prices will remain low, market

6   and supply related risks will not materialize, and none of the aging in-region generation

7   necessary to support reliability in New Orleans or the coal-fired generation in ENO's

8   portfolio will deactivate early. Such a chain of assumptions is contrary to the Company's

9   reasoned expectations. Moreover, even if transmission projects were undertaken to

10 facilitate additional import capability into Amite South and DSG, as the market

11 approaches equilibrium there may not be excess capacity to purchase. Effectively, the

12 transmission-only scenario would leave ENO's customers exposed to significant risks.

13   Importantly, New Orleans is already totally dependent on transmission to serve

14 the needs of its customers. The goal of a prudent local resource plan should be to ensure

15 some amount of local generation is available to make the region less dependent on

16 transmission, not more dependent. This is particularly true in the case of the Amite South

17 and DSG load pockets. Adding more transmission in lieu of in-region generation makes

18 the city more vulnerable to planned and unplanned events such as major storms, while a

19 local generator would reduce that vulnerability. A dispatchable generator increases

20 flexibility to take outages necessary to maintain vital transmission lines. Adding more

21 transmission also does not add reactive power; a generator does.[16]

---

[16]   Mr. Charles Long describes the need for and benefits of reactive power.

1   Accordingly, although the transmission-only approach appears economically

2   competitive under the reduced capacity price sensitivity, which as discussed more fully

3   below, is not a reasonable scenario; and it simply does not make sense to proceed with

4   that option in lieu of building a local generator. New Orleans is already over-reliant on

5   transmission to serve load. Moreover, as discussed by Mr. Charles Long, the terrain in an

6   urban environment with swampy soil conditions like New Orleans makes transmission

7   very difficult and costly to construct. As Mr. Charles Long discusses, the Company has

8   not included detailed design-level transmission estimates because the Company has

9   always planned to mitigate potential NERC violations with a local source of generation

10   located at the Michoud site. If design-level estimates become necessary, it is very likely

11   that projects to mitigate NERC violations will be more costly and will take a considerable

12   amount of time to develop, seek approval, and then construct. Accordingly, for all of

13   these reasons, Case 2 will not meet the Company's objective to deploy resources

14   necessary to meet long-term resource needs in the provision of safe and reliable service at

15   the lowest reasonable cost.

16

17   **B.   The Requested Portfolios**

18   Q30. PLEASE DESCRIBE THE REQUESTED PORTFOLIOS.

19   A.   On March 23, 2017, as aforementioned, the Council's Advisors filed Recommendations

20   with Respect to ENO's New Orleans Power Station Supplemental Filing, which

21   requested that the Company model certain assumptions advanced by Intervenors opposed

22   to NOPS. While legal counsel has advised me that ENO is under no legal obligation to

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
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1   conduct analyses using assumptions advanced by intervenors opposed to the resource at

2   issue, , the Company has performed the requested analyses to the best of its ability in

3   order to facilitate a more timely review of this proceeding.

4   It should be noted that it was requested that the Company utilize AURORA's

5   capacity expansion feature in one of the Requested Portfolios, but the scope of the

6   modeling did not allow that feature to be used.[17]   Instead, the Company attempted to

7   simulate the results of the capacity expansion feature.   Accordingly, the Company

8   conducted AURORA modeling on four portfolios using inputs and assumptions requested

9   in the Advisors' Recommendations at the request of Intervenors.   The Company also

10   performed the same sensitivities for natural gas and MISO capacity prices as was done

11   for the ENO Reference Cases described above.

12   The first Requested Portfolio (labeled "Case 3" in the tables and exhibits)

13   evaluates the addition of the Alternative Peaker.   The second Requested Portfolio

14   (labeled "Case 3G" in the tables and exhibits) evaluates the addition of the originally

15   proposed 226 MW G-frame CT. The third Requested Portfolio (labeled "Case 4A" in the

16   tables and exhibits) evaluates the addition of an incremental 100 MW of solar.[18]   The

17   fourth Requested Portfolio (labeled "Case-4B" in the tables and exhibits) evaluates the

18   addition of 300 MW of wind resources.

19

---

[17]   The capacity expansion algorithm component of the AURORA model would not perform the necessary
iterations through the entire 20-year planning horizon in order to converge on a solution for a particular resource.

[18]   The "incremental" 100 MW of solar in Case 4A is in addition to the 100 MW of solar resources that are
assumed in all of the supplemental AURORA modeling, for a total of 200 MW of solar in Case 4A.

1   Q31.   WHAT COMMON ASSUMPTIONS WERE UTILIZED IN THE REQUESTED

2   PORTFOLIOS?

3   A.   Uniform assumptions adopted in each of the Requested Portfolios include the BP17U

4   forecast of load adjusted for the estimated impact of the Council's 2% DSM Goal,

5   BP17U commodity prices including reference case CO_2, the planned addition by ENO of

6   up to 100 MW of solar resources, and full deployment of Advanced Metering

7   Infrastructure. Sensitivity analyses were conducted for each portfolio using low and high

8   case natural gas price forecasts as well as a sensitivity using sixty percent of the

9   Company's MISO capacity price forecast, which accommodates certain Intervenors'

10   arguments that "updated MISO capacity price forecast of net CONE" should be

11   modeled.[19]

12

13 Q32.   WHAT WERE THE RESULTING TOTAL RELEVANT SUPPLY COSTS OF THE

14   REQUESTED PORTFOLIOS?

15 A.   Figure 4 below summarizes the results of the Requested Portfolios across reference, low

16   and high gas prices.

---

[19]   *See* Advisors' Recommendations at 3.
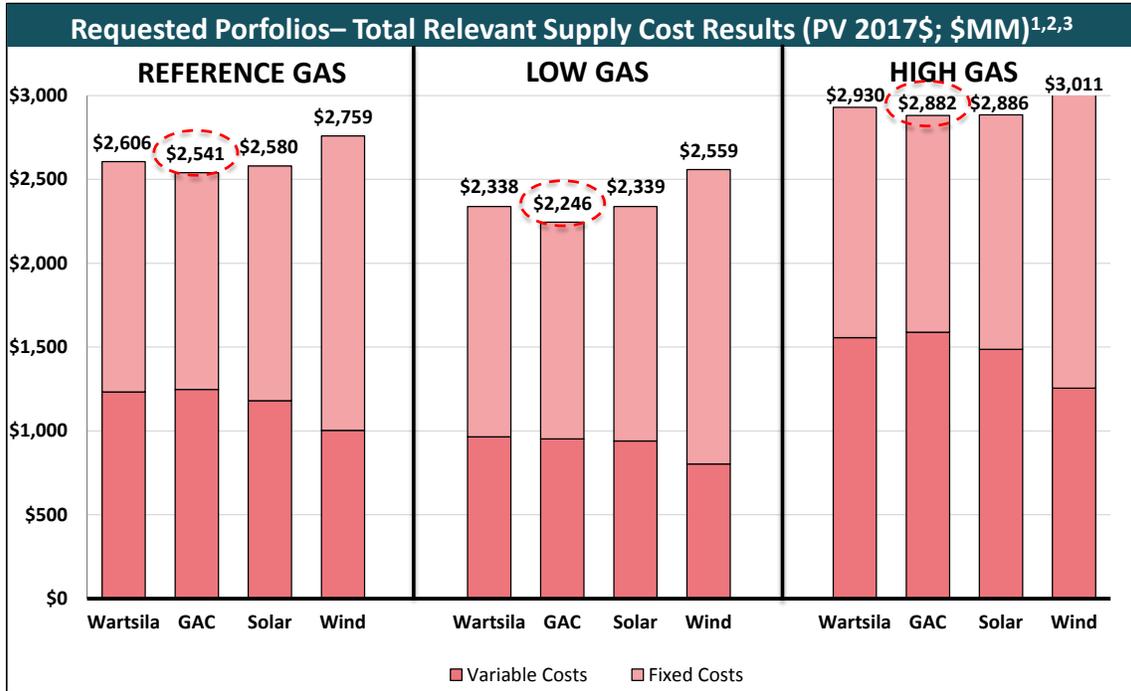
Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

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1 **Figure 4**

Requested Porfolios– Total Relevant Supply Cost Results (PV 2017$; $MM)[1,2,3]

Notes:
1. The Fixed Cost component is the sum of DSM costs, Incremental Resource costs, Transmission costs and Capacity Purchases/(Sales).
2. The Capacity Purchases/(Sales) are based on the MISO South Capacity Price Curve as of May 2016.
3. The 20 year evaluation period of this analysis is (2017 – 2036).

2

3

4 Q33. WHAT WERE THE RESULTS OF THE REQUESTED PORTFOLIOS UNDER THE

5 SENSITIVITY ANALYSES?

6 A. Figure 5 below summarizes the results of the Requested Portfolios using both high and

7 low gas prices as well as projected MISO capacity prices that are 60% of the Company's

8 Reference Case MISO capacity price assumptions.
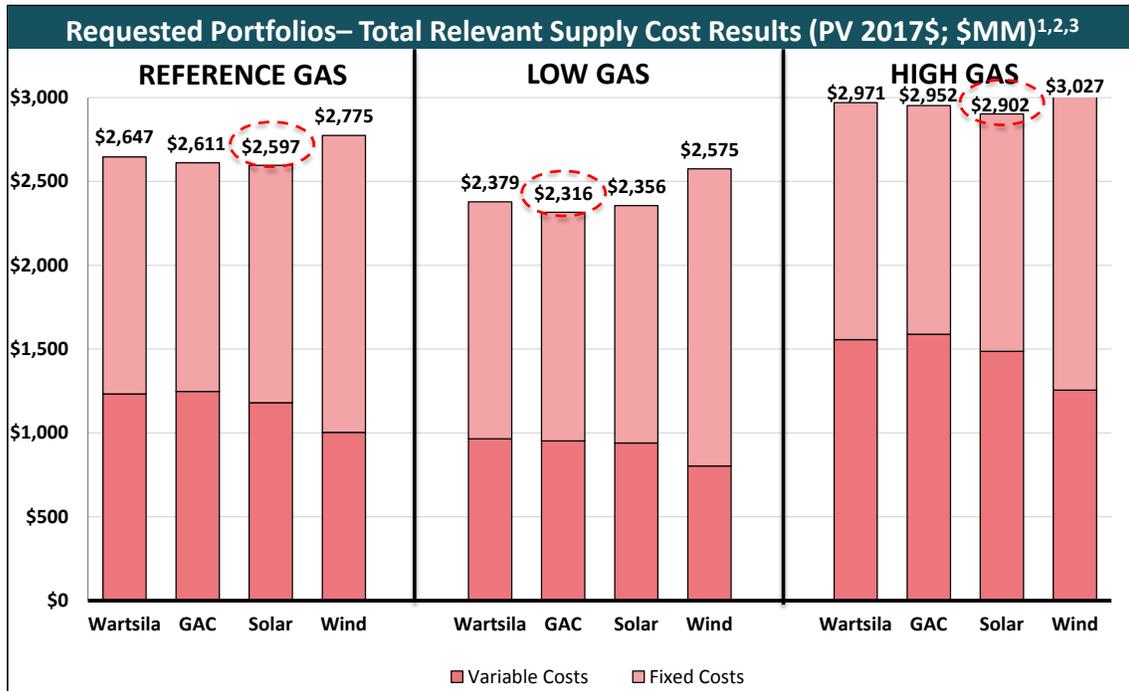
Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
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1

Figure 5

Requested Portfolios– Total Relevant Supply Cost Results (PV 2017$; $MM)[1,2,3]

Notes:
1. The Fixed Cost component is the sum of DSM costs, Incremental Resource costs, Transmission costs and Capacity Purchases/(Sales).
2. The Capacity Purchases/(Sales) are based on the MISO South Capacity Price Curve as of May 2016 at 60% CONE.
3. The 20 year evaluation period of this analysis is (2017 – 2036).

2

3

4 Q34. DO YOU HAVE CONCERNS WITH THE ASSUMPTIONS ASSOCIATED WITH

5   THE REQUESTED PORTFOLIOS THAT AFFECT HOW THOSE RESULTS

6   SHOULD BE CONSIDERED IN EVALUATING THE COMPANY'S APPLICATION

7   TO CONSTRUCT NOPS?

8 A.   Yes. As mentioned, the Requested Portfolios include several assumptions that were

9   recommended by certain Intervenors in their direct testimony filed in January 2017.

10   First, the Requested Portfolios include the Council's DSM Goal referenced in Council

11   Resolution R-15-599, which describes a goal of "increasing the projected savings from

12   the Energy Smart program by 0.2% per year, until such time as the program generates

1   kWh savings at a rate equal to 2% of annual kWh sales."[20]   Accordingly, for the

2   Requested Portfolios, the Company adjusted the BP17U load forecast by reducing sales

3   each year by 0.2% until a 2.0% incremental reduction, as measured over the prior three-

4   year average sales, was achieved. After that, it reduced sales each year by 2.0% of the

5   prior three-year average sales. In this manner, ENO's forecasted load was significantly

6   reduced during the planning period.

7

8   Q35.   IS THE COUNCIL'S DSM GOAL ACHIEVABLE?

9   A.   Not likely, and in any event it would not be cost-effective. The Company retained

10   Navigant to assess the upper bounds of EE potential that could be achieved by ENO in a

11   cost-effective manner. In the event that the upper bound of annual incremental cost-

12   effective achievable savings potential was something less than 2.0%, Navigant was also

13   asked to evaluate whether it would be theoretically possible, regardless of cost, to achieve

14   2.0% per year annual incremental savings. Finally, Navigant was asked to estimate the

15   costs associated with achieving a 2.0% annual incremental savings level and sustaining it

16   at that level over the study period. Those costs were incorporated into the Total Relevant

17   Supply Cost analyses for the Requested Portfolios. Navigant's report is attached as

18   Exhibit SEC-14.

19

---

[20]   *See* Resolution No. R-15-199.

1   Q36.   WHAT DID NAVIGANT CONCLUDE?

2   A.   Navigant concluded that "with a comprehensive portfolio of efficiency measures,

3   aggressive marketing and incentives, and realistic assumptions, ENO could cost-

4   effectively reduce forecast load by roughly 17% over the next 20 years, an average of

5   0.85%/year."[21] Navigant further concluded that, while it achieved 2.0% in one year

6   using unrealistic assumptions and including measures that are not cost-effective, even

7   then it is not sustainable and declines after 2023 due to market saturation of the

8   measures.[22] Navigant further added that "the high ramp rate of this scenario is likely

9   unrealistic and would be difficult to achieve under real-world conditions."[23]

10   Based on Navigant's assessment, I believe that the results of the Requested

11   Portfolios are skewed because they assume a level of load reduction that is over twice the

12   level that could be achieved using aggressive assumptions and cost-effective measures.

13   The aggressive savings potential level itself (an average of 0.85% per year) is more than

14   double what ENO is actually achieving currently (approximately 0.4% per year), which

15   further indicates that a 2.0% savings goal in not realistically or cost-effectively

16   achievable. Finally, the benchmarking survey included in Navigant's Report in Figure 9

17   show that 2.0% is nowhere near the average annual achievable "potential savings" of

---

[21]   *See* SEC-14 at 3.

[22]   *Id*. at 3, 13, and 21.

[23]   *Id*. at 3.

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
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1   other utilities in the South, which ranges from 0.53% to 1.07%.[24] And actual savings for

2   utilities in the South in 2015 tended not to achieve their potential savings.[25]

3

4   Q37.   PLEASE ELABORATE ON NAVIGANT'S CONCLUSIONS REGARDING THE

5   ENERGY   EFFICIENCY   POTENTIAL   FOR   ACHIEVING   2.0%   ANNUAL

6   INCREMENTAL SAVINGS.

7   A.   Navigant concluded that achieving 2.0% annual incremental savings is theoretically

8   possible, but only for one year, and in order to achieve that result they had to assume that

9   100% of participant costs are covered by incentives, include program marketing

10   effectiveness values that are "higher than realistic," and use a total resource cost ("TRC")

11   screening level that was greater than or equal to 0.3, which means that many of the

12   measures included in the portfolio are not cost effective.[26] Further, the 2.0% savings

13   potential level was only achieved in 2023, and then it tailed off significantly as the

14   potential savings available from the measures were exhausted.[27] Moreover, the estimated

15   costs of that scenario exceed $1.4 billion over the 20-year period.[28] In contrast, the

16   estimated costs of the very aggressive, yet maximum achievable scenario were

17   approximately $400 million.[29] While the Company supports developing and pursuing

---

[24]   *See* Exhibit SEC-14 at Figure 9, p. 28.

[25]   *See* Exhibit SEC-14 at Figure 10, p. 29.

[26]   *See* Exhibit SEC-14 at 13.

[27]   *See* Exhibit SEC-14 at 21-22.

[28]   *See* Exhibit SEC-14 at 5. The estimated costs to theoretically sustain potential savings at the 2.0% level over the 20-year period were $2.3 billion. *Id.*

[29]   *See* Exhibit SEC-14 at 5.

1   cost-effective DSM, based on Navigant's conclusions, the Council's DSM goal requires

2   theoretical assumptions about unknown measures that have not yet been proven in actual

3   market conditions, and thus lead me to conclude that the goal is simply not achievable at

4   this time.[30] Accordingly, the results of the Requested Portfolios do not constitute a

5   reasonable basis for evaluating the resource options available to meet ENO's resource

6   needs because they utilize an unrealistically low load forecast.

7

8   Q38.   IS   THE REQUESTED RECOMMENDATION TO ASSUME A CAPACITY PRICE

9   FORECAST THAT IS "NET CONE" REASONABLE FOR PURPOSES OF ENO'S

10   MODELING?

11   A.   No. The Company's forecast assumes that as equilibrium approaches (where supply and

12   demand are in balance) and the market tightens, capacity prices in MISO will trend

13   towards, and eventually equal the cost of new entry ("CONE"). Apparently in response

14   to the position taken by certain Intervenors who have opposed the construction of NOPS,

15   the Advisors requested that the Company use a different methodology to project capacity

16   prices called "Net CONE," or the cost of new entry reduced by "potential energy market

17   revenues."[31] Simply put, this is not the methodology used by MISO to calculate capacity

18   prices, which is conceded by Mr. Luckow, the Intervenors' witness who advanced this

19   theory in his testimony, admitting that assuming capacity prices trend towards CONE is

---

[30]   As I explained in my November 2016 Supplemental Direct Testimony at page 9, the 2015 ICF International
DSM Potential Study also supports the conclusion that achieving 2.0% annual incremental savings is not achievable
in a cost-effective manner.

[31]   Luckow Direct at 17.

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
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1   "logical in theory—and this is why such markets use CONE as a basis for setting price

2   rules."[32]   The testimony goes on to state, however, that in "other capacity markets," net

3   CONE is used.[33]

4   The first problem with this assumption is that it appears to be completely

5   arbitrary. In fact, in order to reduce ENO's assumption around capacity prices to align

6   with his theory, Mr. Luckow randomly picked a value within the range of historic

7   capacity prices in PJM, a completely different regional transmission organization

8   ("RTO"), with different market dynamics.[34] To the extent it has any analytical basis, in

9   so far as the Intervenors have described Net CONE, at best it is a theoretical argument

10   that relies on academic conjecture about bidding behavior and auction outcomes. In

11   contrast, the Company's projection is based on a reasonable trajectory toward CONE,

12   which represents a "logical" assumption that prices will approach CONE as the market

13   tightens.

14   Assuming that the prices that ENO will have to pay for future capacity are

15   something less than CONE assumes that either the market will not approach equilibrium,

16   and/or that there is a completely efficient capacity market. Yet in the 2015 State of the

17   Market Report for the MISO Electricity Markets (published June 2016), MISO's

18   independent market monitor noted that the "PRA continues to reflect a poor

19   representation of the demand for capacity, which undermines its ability to provide

---

[32]   *Id.*

[33]   *Id*.

[34]   *Id*. at 18-19.

1   efficient economic signals."[35] The Report went on to say that "MISO's capacity market is

2   not designed to provide efficient prices and incentives to govern investment and

3   retirement decisions."[36] Mr. Luckow's theory rests on the existence of an "efficient

4   capacity market," which MISO is not; and on the belief that significant merchant

5   generation investment is likely in MISO South, which is not likely given the capacity

6   market structure. In short, the Company modeled sensitivities around reduced capacity

7   prices, as requested by the Advisors, but the Company does not endorse these reduced

8   capacity prices because based on its analysis, equilibrium is expected to occur sometime

9   around 2022 and there is no reasonable basis to assume future capacity prices at net

10   CONE.

11

12   Q39.   ARE ADDITIONAL RENEWABLE RESOURCES APPROPRIATE FOR MEETING

13   ENO'S PEAKING AND RESERVE CAPACITY NEEDS?

14   A.   No.   During periods of peak demand, generating resources must be able to respond

15   quickly to changing conditions on the electric system in order to maintain reliability by

16   starting on short notice and responding to dispatch signals to quickly ramp up or down

17   (*i.e.*, "dispatchable"). Fossil-fueled resources like the CT and Alternative Peaker are

18   technologically suited for peaking and reserve roles precisely because they are

19   dispatchable. That capability supports local area reliability and, as Mr. Jonathan Long

---

[35]   2015 State of the Market Report at 16. Available at
https://www.misoenergy.org/Library/Repository/Report/IMM/2015%20State%20of%20the%20Market%20Report.pdf.

[36]   *Id*. at 20.

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
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1   describes, facilitates the integration of renewable resources in or near the Company's

2   service area by providing a quick start resource capable of coming online and ramping

3   quickly to address the intermittency associated with renewables.

4

5   Q40.   PLEASE ELABORATE ON THE ISSUES ASSOCIATED WITH RENEWABLES

6   SUCH AS WIND AND SOLAR AND WHY THEY ARE NOT VIABLE

7   ALTERNATIVES TO MEET PEAKING AND RESERVE NEEDS.

8   A.   Renewable resources such as wind and solar are intermittent because they rely on the

9   wind and sun to produce energy, thus limiting the Company's ability to rely on them to

10   meet customer demand. In other words, the generating capacity of renewables such as

11   wind and solar are not dispatchable because the available capacity is solely a function of

12   the amount of wind and sunlight available at a given time and thus cannot be counted on

13   for meeting peak demand. As a result, renewables must be supported by dispatchable

14   resources that can ramp up and produce replacement energy when the wind is either not

15   blowing or blowing less than projected. Dispatchable resources are similarly required

16   when the sun sets (which is typically when the Company's load approaches its summer

17   peak) or cloud cover and unexpected weather limits the output of solar throughout the

18   day. Based on my own experience, I can state that thunderstorms and severe weather in

19   summer afternoons and evenings, which coincides with the Company's peak demand, are

20   common occurrences in New Orleans.

21   In the case of wind resources, the greatest potential lies in areas remote from the

22   Company's service area requiring significant transmission upgrades to deliver those

1   resources to New Orleans. Moreover, wind resources typically peak during late evening

2   and early morning hours when the Company's load is typically the lowest, which could

3   complicate the dispatch of vital baseload resources that typically operate 24 hours a day,

4   7 days a week. Another important consideration for wind and solar resources is the land

5   intensity of those resources. Based on the Company's own experience, solar resources

6   can require approximately 7-10 acres of land per MW, as evidenced by the Company's 1

7   MW solar pilot project in New Orleans East. Wind resources can require over 60 acres

8   of land per MW, making it a practical impediment to develop wind resources in or around

9   the Company's service area. Accordingly, even if wind and solar resources were capable

10   of serving in a peaking or reserve supply-role (which they are not), the practical

11   impediments to development prevent them from meeting the Company's need for a local

12   peaking and reserve capacity resource.

13

14   Q41. DOES THIS MEAN THAT INTERMITTENT RESOURCES SUCH AS SOLAR AND

15   WIND HAVE NO PLACE IN ENO'S SUPPLY PORTFOLIO?

16   A.   Not at all. To the extent there are cost-effective sources of renewable energy available to

17   the Company, they could provide benefits to customers in the form of increased diversity

18   of supply, a hedge against exposure to volatility in commodity prices (*e.g.,* natural gas),

19   and other environmental attributes. Moreover, the Company has committed to pursuing

20   up to 100 MW of renewable resources, and it has included that planned capacity in each

21   of the AURORA simulations described above.

22

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Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

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1   **C.   Evaluation of the Modeling Results**

2   Q42. CONSIDERING THE ISSUES YOU DESCRIBED WITH RESPECT TO THE

3   REQUESTED PORTFOLIOS, DO THE TOTAL RELEVANT SUPPLY COST

4   ANALYSES CONTINUE TO SUPPORT THE COMPANY'S APPLICATION TO

5   CONSTRUCT NOPS?

6   A.   Yes. As I explained above, the 226 MW CT (Case 1G) is the most cost-effective

7   resource alternative under low, reference and high gas price projections and using the

8   Company's MISO capacity price forecast. While the Reference Case with the

9   Alternative Peaker (Case 1) is projected to result in a higher Total Relevant Supply Cost

10   when compared to Case 1G, the increase is comparable to the transmission-only case

11   (Case 2). Even under the discounted capacity price assumption, which I explained above

12   is arbitrary, Case 1G is the most cost-effective alternative in the low gas sensitivity case

13   and is virtually tied with Case 2 in the reference and high gas scenarios. While Case 1 is

14   projected to result in a higher cost when compared to Case 1G in the reference and high

15   gas scenarios, the increase is comparable to that of Case 2 in the low gas scenario. As I

16   have explained, deploying a dispatchable unit in New Orleans mitigates market and

17   supply related risks, especially as the market reaches equilibrium. Further, Mr. Charles

18   Long explains the additional local reliability benefits, which will not be not realized

19   under a transmission-only scenario. Accordingly, for these reasons, and for all of the

20   additional reasons described above in my testimony, when confronted with comparatively

21   equal Total Relevant Supply Costs for these two portfolios, the additional benefits of a

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Supplemental and Amending Direct Testimony of Seth E. Cureington
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1   local, dispatchable resource clearly favors NOPS over the non-viable, transmission-only

2   option.

3   Furthermore, the Requested Portfolios results favor Case 1G in all of the gas price

4   scenarios when using the Company's forecasted capacity prices. Those results change

5   slightly when using a discounted capacity price forecast that is 60% of the reference case,

6   but even in that scenario Case 1G is the most cost-effective alternative in the low gas

7   case. Case 1G and Case 1 have a slightly higher cost when compared to Case 4A in the

8   reference and high gas cases; however, the increase is comparable to that of Case 4A in

9   the low gas scenario. Thus, given the identified planning needs, even in the Requested

10   Portfolios, the benefits of adding local, dispatchable generation prevail.

11

12   Q43. IF THE 226 MW CT, THE ALTERNATIVE PEAKER, AND THE INCREMENTAL

13   100 MW SOLAR PORTFOLIOS ARE ROUGHLY EQUAL IN TERMS OF TOTAL

14   RELEVANT SUPPLY COSTS, AS IN THE REQUESTED PORTFOLIOS, ARE

15   THERE ADDITIONAL CONSIDERATIONS THAT FAVOR ONE OVER THE

16   OTHER?

17   A.   Yes. Traditional gas-fired generating units like the CT and Alternative Peaker are

18   preferred to meet current and projected long-term peaking and reserve capacity needs due

19   to their lower installed cost and operational flexibility when compared to other

20   dispatchable resource alternatives. As stated, renewable resources like solar and wind are

21   intermittent and must be backed up with dispatchable resources to ensure sufficient

22   resources are available to ramp up and produce replacement energy when it is cloudy,

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Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

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1   late in the day, or the wind is not blowing. Furthermore, the Company's summer peaks

2   occur late in the day when customers are returning home from work and turning on lights

3   and appliances and lowering thermostat settings. Given that profile, solar is not an ideal

4   peaking resource as it is often unavailable or declining (*i.e*., the sun is setting) right when

5   it is needed most. Moreover, as I described above, having a local, dispatchable resource

6   actually supports the addition of future renewable resources.

7   I also described in my Direct Testimony how MISO grants solar resources less

8   capacity credit in its Resource Adequacy ("RA") process, which means that it takes more

9   MW of solar generation than an equivalent MW of CT generation for the same RA credit.

10   Thus, the additional capacity provided by a 226 MW CT at a Total Relevant Supply

11   Costs comparable to the 100 MW of solar should not be overlooked in its contribution to

12   meeting ENO's RA requirements in MISO and the Company's long-term resource needs.

13   For all these reasons, given that the 100 MW solar portfolio and the 226 MW CT

14   are virtually tied in terms of Total Relevant Supply Costs, the 226 MW CT is the better

15   resource for meeting ENO's identified long-term planning needs while considering risk.

16

17   Q44. IS THE COMPANY RECOMMENDING THE ALTERNATIVE PEAKER AS A

18   REASONABLE ALTERNATIVE TO THE 226 MW CT?

19   A.   The Company has included the Alternative Peaker as a reasonable alternative to the

20   originally proposed 226 MW CT, recognizing that it represents a higher installed cost per

21   kW and higher projected operating cost. Mr. Jonathan Long explains that the Alternative

22   Peaker has lower water usage, a low emissions profile, an enhanced ability to support

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Seth E. Cureington
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   renewable resources (because of its ability to start and achieve full load in a very short

2   period of time, and its ability to start and stop multiple times in a single day), a lower heat

3   rate, and the inclusion of black-start capability.[37]   Further, this option is only 2.3% more

4   expensive on average than the transmission-only alternative in the Company's Reference

5   Cases, and a mere 1.3% more expensive on average than the Requested 100 MW solar

6   portfolio, but it will add a local source of dispatchable generation capable of providing

7   real and reactive power and mitigating market and supply-related risks when compared to

8   the transmission-only and solar portfolios (albeit to a lesser degree than the CT), which

9   makes the Alternative Peaker a reasonable alternative to the 226 MW CT and a better

10   option than transmission-only and solar alternatives.

11

12   Q45. DID   THE   ADVISORS   REQUEST   THAT   ENO   PROVIDE   ADDITIONAL

13   JUSTIFICATION FOR ANY NEW RESOURCE THAT RESULTS IN CERTAIN

14   LEVELS OF EXCESS CAPACITY?

15   A.   Yes, but the underlying concern, which has been raised by the Intervenors opposed to

16   NOPS, is not reasonable because it implies that a utility has the ability to add exactly the

17   amount of incremental capacity that it projects that it will need each year. That is simply

18   not feasible, and it is also not unusual for utilities engaged in prudent long-term resource

19   planning to find that their existing and planned capacity does not exactly align with peak

20   load requirements every year.   The important point is that the Company is projected to

21   be approximately 100 MW short of capacity over the first ten years of the planning

---

[37]   *See* Jonathan Long Supplemental at 6, 7.

1   horizon, and more than double that amount over the second ten years, and both the 226

2   MW CT and the Alternative Peaker reasonably address ENO's capacity deficit, with the

3   Alternative Peaker projected to leave the Company slightly short at the end of the

4   planning period and the CT leaving the Company a bit long. Neither of those results are

5   unusual or unreasonable. Further, neither alternative completely addresses ENO's short-

6   term or long-term peaking and reserve deficit.

7

8   Q46.   SHOULD THE COUNCIL CONSIDER THE RESULTS OF THE ANALYSES

9   CONDUCTED IN THE COMPANY'S NOVEMBER 2016 SUPPLEMENTAL FILING

10   AS WELL?

11   A.   The results of the November 2016 analyses are consistent with ENO's position that the

12   226 MW CT is a cost-effective resource alternative for addressing the Company's

13   identified long-term resource planning needs while considering risk. The more recent

14   analyses included with this Supplemental Testimony are based on different assumptions,

15   which are described above, but continue to support that NOPS is cost-effective for

16   addressing the Company's identified long-term resource planning needs while

17   considering risk.

18

19   **VI.   CONCLUSION**

20   Q47.   DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

21   A.   Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **SETH CUREINGTON**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

_____
Seth Cureington

**SWORN TO AND SUBSCRIBED BEFORE ME
THIS 27TH DAY OF JUNE, 2017**

_____
NOTARY PUBLIC

My commission expires: _at death_

TIMOTHY S. CRAGIN
NOTARY PUBLIC (La. Bar No. 22313)
Parish of Orleans, State of Louisiana
My Commission is issued for Life

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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

EXHIBIT SEC-10

through

EXHIBIT SEC-13

PUBLIC VERSION

JULY 2017

Entergy New Orleans – Energy Efficiency Potential Study

Prepared for:

Entergy New Orleans

Submitted by:

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Reference No.: 195598
June 26, 2017

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

DISCLAIMER

This report was prepared by Navigant Consulting, Inc. (Navigant) for Entergy New Orleans (ENO). The work presented in this report represents Navigant's professional judgment based on the information available at the time this report was prepared. Navigant is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. NAVIGANT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

1. EXECUTIVE SUMMARY

Introduction and Background

The New Orleans City Council (Council) recently issued a resolution that stated: "the Council believes it would be reasonable in the development of subsequent Energy Smart Program Years (Program Year 7 and beyond) for the Company to incorporate in its Energy Smart and IRP filings for evaluation by the Advisors, Intervenors, and the Council the goal of increasing the projected savings from the Energy Smart program by 0.2% per year, until such time as the program generates kWh savings at a rate equal to 2% annual kWh sales."[1] The purpose of this report is to provide an independent assessment of the EE savings potential for the ENO territory and to assess whether it is possible to achieve the 2% reduction goal in the ENO territory in a cost-effective manner.

Approach to Estimating Market Potential

Using Navigant's Demand Side Management Simulator (DSMSim™) model, Navigant calculated achievable energy efficiency potential across ENO's territory. As outlined in Figure 1, the central inputs to the model include characterizing the ENO territory market, characterizing the energy efficiency measures for inclusion in the analysis and solidifying financial model assumptions.

Figure 1. Energy Efficiency Potential Study Approach for ENO

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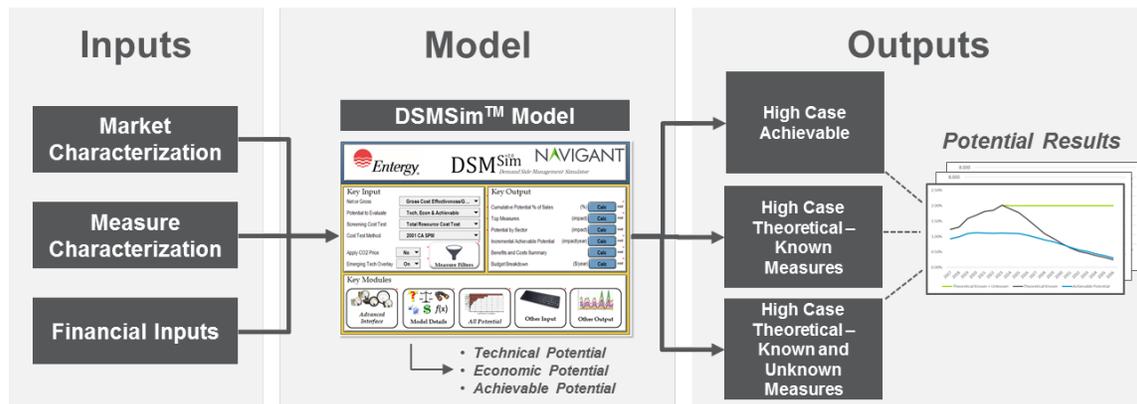
[1] Resolution NO. R-15-599, Docket NO. UD-08-02, Council Review of Energy Smart Program Year 4 and Energy Smart Programs' Sources and Uses of Funds, and Available Funding Sources. December 10, 2015.

Source: Navigant

Market Characterization

Navigant worked with ENO to understand the breakdown of total electricity consumption by customer sector, based on ENO's forecast. Total electricity demand is projected to increase from 5,586 GWh in 2017 to 6,628 GWh in 2036, with almost proportional increases in residential and commercial and industrial (C&I) consumption. This electric consumption forecast serves as the basis of the energy efficiency market potential analysis. Details are provided in Appendix A.

Measure Characterization

This potential study leveraged the database of electric measures characterized as part of the 2015 Arkansas Energy Efficiency Potential study, which was conducted by Navigant.[2] The 2015 study used the Arkansas Technical Reference Manual (TRM) to specify the effective useful life (EUL) and how to calculate energy savings for each measure listed in the TRM. Because there is not a New Orleans or Louisiana TRM, using the Arkansas TRM was deemed appropriate by the Navigant team. Navigant developed estimates of implementation costs, estimates of measure density, baseline density and technical applicability in addition to calculating per unit savings based on the TRM. Electric-only impacts are captured as part this ENO analysis, and gas savings do not impact the cost-benefit evaluation of measures (i.e. if implementation of an electric measure increases or decreases gas use).

The Arkansas measure assumptions serve as a basis for this study given the relatively few changes in technology performance or measure costs since the 2015 study. In cases where material changes to measures have occurred, Navigant updated the underlying measures' assumptions to reflect more recent inputs.

Financial Inputs

Appendix A. Model Global Assumptions key global assumptions used in the analysis for all three scenarios. The significance of these global assumptions is that they serve as key financial and valuation parameters (e.g., inflation and discount rates, avoided costs, etc.) used in the calculation of the achievable potential.

Estimating Achievable Potential

Navigant evaluated three potential scenarios as part of this study which included the following:

- **Scenario 1: High Case Achievable**: Represents Navigant's best estimate regarding a level of EE potential that could be achievable by ENO with an aggressive roll-out of EE programs.

- **Scenario 2: High Case Theoretical – Known Measures**: Represents a theoretical level of potential under a set of conditions that may not be realistic. This theoretical scenario yields a

---

[2] Navigant Consulting, Inc., Arkansas Energy Efficiency Potential Study, June 1, 2015, http://www.apscservices.info/pdf/13/13-002-U_212_2.pdf

2.0% per year annual incremental savings potential as a percentage of utility sales in at least one year of the simulation horizon.

- **Scenario 3: High Case Theoretical – Known and Unknown Measures**: Identical to Scenario 2 with the exception that the incremental savings as a percentage of sales is assumed to be held at 2.0% per year after 2024, the year in which Scenario 2 reaches 2.0%.

Additional information about these scenarios is provided in Chapter 3.

Key Findings

Key study findings include the following:

- The High Case Achievable Scenario illustrates 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. The cost of these savings is roughly $16 million/year in 2017 and $25 million/year in 2024. Costs decline thereafter as the market for known measures saturates. This portfolio is cost effective with a Total Resource Cost (TRC) ranging from 1.7-2.0 over the simulation horizon.

- The High Case Theoretical – Known Measures Scenario calculates the potential savings and program cost for a scenario where a peak incremental savings as a percentage of forecast sales equals 2.0%, which occurs in 2023 and declines thereafter due to market saturation of known measures. In this scenario, forecast load could be reduced by 23.4% over the 20-year simulation horizon, an average of 1.17%/year. Costs for this scenario are considerably higher than in the High Case Achievable Scenario due to higher incentive levels and increases in marketing expenditures. Annual expenditures to achieve this ramp up are roughly $59 million in 2017, rising to about $112 million in 2023 and declining thereafter due to market saturation. However, the high ramp rate of this scenario is likely unrealistic and would be difficult to achieve under real-world conditions.

- The High Case Theoretical – Known and Unknown Measures Scenario calculates the potential savings and costs for a portfolio that ramps up to 2.0%/year of incremental savings by 2023, and holds that level of incremental savings through 2036. This scenario requires the assumption that emerging efficiency measures, not currently known, will enter the market at a cost roughly equivalent to the modeled costs in 2023, escalated for inflation. This scenario is therefore the most theoretical and costly of all three scenarios, and requires assumptions that are highly theoretical and have not been proven in actual market conditions.

The incremental potential savings as a percentage of sales,[3] and the calculated budgets required, for each of the three scenarios analyzed are provided below in Table 1 and Table 2.

---

[3] Navigant used a fixed forecast which does not change with each increment of efficiency achieved year over year.

Table 1. Incremental Potential by Scenario As a Percentage of Forecasted Sales

Year	Achievable	Theoretical Known Measures	Theoretical Known + Unknown Measures
2017	0.92%	1.23%	1.23%
2018	0.99%	1.30%	1.30%
2019	1.09%	1.58%	1.58%
2020	1.13%	1.69%	1.69%
2021	1.11%	1.81%	1.81%
2022	1.10%	1.85%	1.85%
2023	1.11%	2.01%	2.01%
2024	1.10%	1.90%	2.00%
2025	1.10%	1.77%	2.00%
2026	1.04%	1.55%	2.00%
2027	0.96%	1.33%	2.00%
2028	0.89%	1.09%	2.00%
2029	0.83%	0.94%	2.00%
2030	0.74%	0.77%	2.00%
2031	0.65%	0.63%	2.00%
2032	0.57%	0.52%	2.00%
2033	0.51%	0.46%	2.00%
2034	0.44%	0.38%	2.00%
2035	0.38%	0.32%	2.00%
2036	0.31%	0.25%	2.00%

Table 2. Estimated Total Budget by Scenario

Year	Achievable	Theoretical Known Measures	Theoretical Known + Unknown Measures
2017	$16,337,839	$59,178,008	$59,178,008
2018	$18,497,144	$64,668,401	$64,668,401
2019	$20,693,198	$77,904,113	$77,904,113
2020	$22,242,507	$85,198,537	$85,198,537
2021	$22,604,926	$94,963,854	$94,963,854
2022	$23,269,646	$99,948,935	$99,948,935
2023	$24,540,273	$111,776,522	$111,776,522
2024	$24,855,094	$110,115,415	$112,248,420
2025	$24,577,105	$103,770,105	$114,462,735
2026	$23,869,782	$95,241,648	$116,931,982
2027	$22,715,858	$85,292,210	$119,535,115
2028	$22,491,790	$76,982,709	$122,477,648
2029	$21,262,691	$66,801,521	$125,236,611
2030	$19,569,272	$57,773,006	$128,062,123
2031	$17,918,234	$50,518,123	$131,014,890
2032	$16,306,604	$44,381,172	$134,102,404
2033	$14,820,661	$39,347,486	$137,104,595
2034	$13,493,010	$35,351,082	$140,266,300
2035	$12,327,376	$32,199,756	$143,532,518
2036	$11,391,712	$30,363,460	$147,103,475

2. INTRODUCTION

Background

The New Orleans City Council (Council) recently issued a resolution that stated: "the Council believes it would be reasonable in the development of subsequent Energy Smart Program Years (Program Year 7 and beyond) for the Company to incorporate in its Energy Smart and IRP filings for evaluation by the Advisors, Intervenors, and the Council the goal of increasing the projected savings from the Energy Smart program by 0.2% per year, until such time as the program generates kWh savings at a rate equal to 2% annual kWh sales."[4] The purpose of this report is to provide an independent assessment of the EE savings potential for the ENO territory and to assess whether it is possible to achieve the 2% reduction goal in the ENO territory in a cost-effective manner.

Organization of Report

This report is organized as follows:

- Section 3 describes the approach to estimating achievable potential and the scenarios evaluated.
- Section 4 describes the results of the high case achievable, high case theoretical known measures, and high case theoretical known and unknown measures scenarios.
- Section 5 benchmarks this study's achievable potential results against neighboring states and utilities.
- Section 6 provides program recommendations for immediate and future implementation.
- Appendix A provides additional modeling assumptions.

Caveats and Limitations

The caveats and limitations associated with the results of this study are detailed in this section.

Forecasting Limitations

Navigant obtained future energy sales forecast from ENO. This forecast contains assumptions, methodologies, and exclusions. Navigant has leveraged the assumptions underlying these forecasts, as much as possible, as inputs into the development of the Reference Case stock and energy demand projections. Where sufficient and detailed information could not be extracted, Navigant developed independent projections of commercial building stock. These independent projections were developed based on secondary data resources and in collaboration with ENO. These secondary resources and any underlying assumptions are referenced throughout this report.

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[4] Resolution NO. R-15-599, Docket NO. UD-08-02, Council Review of Energy Smart Program Year 4 and Energy Smart Programs' Sources and Uses of Funds, and Available Funding Sources. December 10, 2015.

Program Design

The results of this study provide a big picture view of future savings potential in ENO's service territory. However, this study is not considered a detailed program design tool. The nature of potential studies is for long-term planning and hence estimates should not be applied to short-term DSM planning activities.

Measure Characterization

Efficiency potential studies may employ a variety of primary data collection techniques (e.g., customer surveys, on-site equipment saturation studies, and telephone interviews), which can enhance the accuracy of the results, though not without associated cost and time requirements. Due to the limited timeline for the development of this potential study for the ENO territory, Navigant utilized the measure characterization from a 2015 EE potential study conducted by Navigant for Entergy Arkansas and six other investor-owned utilities in that state.[5] Additional reasons for leveraging this study include similar energy efficiency measure mixes, comparable climate, and the existence of an established Technical Reference Manual (TRM), (which Louisiana and New Orleans currently do not have). To ensure the analysis accounted for differences in ENO's territory in 2017, Navigant made several key adjustments to the Arkansas-based EE measures to reflect 2017 markets and ENO's unique conditions.

Furthermore, the team considers the measure list used in this study to appropriately focus on those EE measures likely to have the highest impact on savings potential over the potential study time horizon. However, there is always the possibility that emerging technologies may arise that could increase savings opportunities over the forecast horizon, and broader societal changes may affect levels of energy use in ways not anticipated in the study.

Net Savings Study

Navigant and ENO agreed to show savings from this study at the net level, rather than gross, consistent with the existing reporting requirements and savings goals established as net of free-ridership. This means all savings reported in this study account for the effect of possible free ridership.

Unknown Measures

The High Case Theoretical – Known and Unknown Measures scenario assumes a hypothetical suite of currently unknown measures will become available in the future at an assumed aggregate cost ($/kWh basis) that is extrapolated from the modeled output. These specific measures (e.g., possible future emerging technologies not currently on the market) have not been identified as part of this study and would potentially permit maintaining the modeled level of savings.

Study Uncertainty

---

[5] Navigant Consulting, Arkansas Energy Efficiency Potential Study, June 1, 2015,
http://www.apscservices.info/pdf/13/13-002-U_212_2.pdf

The forecasting nature of potential studies have inherent uncertainty. Potential studies include thousands of data points and assumptions, including utility forecasting, measure parameters, existing saturation levels, avoided costs, program assumptions, measure costs, and other inputs. Eliminating uncertainty is impossible, but the use of best available data minimizes the impact of these uncertainties.

3. APPROACH TO ESTIMATING ACHIEVABLE POTENTIAL

This section describes the methodology Navigant employed for estimating energy savings across the ENO service territory, including measure characterization, reference case forecast, and the definition of technical, economic, and achievable potential.

Estimating Achievable Potential

Figure 2 shows a graphical representation of technical, economic, and achievable potential. Navigant follows methodologies for conducting energy efficiency potential studies that have been developed and refined over the years through industry experience and guidebooks.[6] This study defines technical potential as the total energy savings available, assuming all installed measures can *immediately* be replaced with the "efficient" measure/technology—wherever technically feasible—regardless of the cost, and market acceptance. Economic potential is a subset of technical potential, using the same assumptions as technical potential, but including only those measures that have passed the benefit-cost test chosen for measure screening. Achievable potential is a subset of economic potential that considers the likely rate of DSM acquisition, given factors like the rate of equipment turnover, simulated incentive levels, consumer willingness to adopt efficient technologies, and the likely rate at which marketing activities can facilitate technology adoption. The goal of this study is to calculate the electric achievable potential in ENO service territory.

Figure 2. Technical, Economic, and Achievable Potential
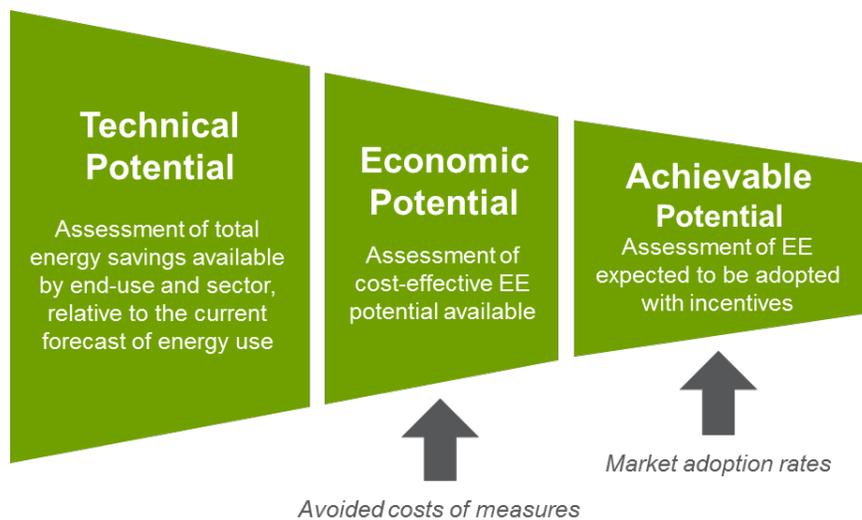
Source: Navigant

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[6] For more general information on methods and approaches used for energy efficiency potential studies, please see USEPA/USDOE joint report titled *Guide for Conducting Energy Efficiency Potential Studies: A Resource of the National Action Plan for Energy Efficiency*, November 2007.

Market Characterization

Figure 3 shows the breakdown of total electricity consumption by customer sector forecasted for 2017, based on ENO's load forecast. Approximately, 40% of electricity consumption comes from the residential sector – equivalent to 2,346 GWh – while 60% comes from the commercial and industrial (C&I) sector – equivalent to 3,510 GWh.

Figure 3. 2017 Electricity Consumption by Sector (Total = 5,586 GWh)
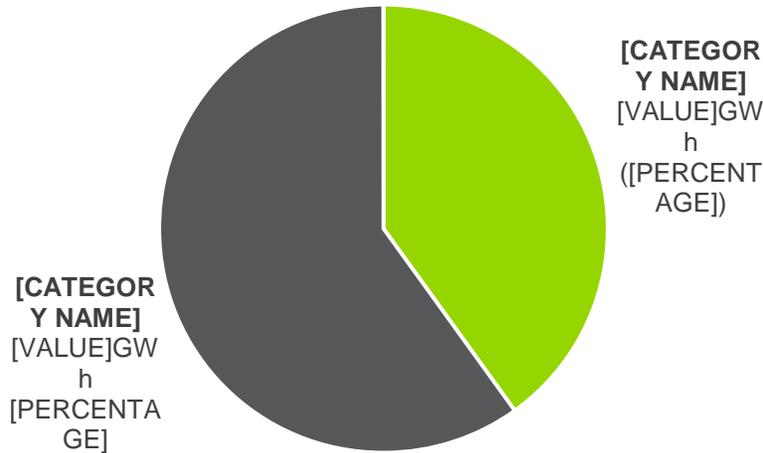
Source: ENO Load Forecast

Figure 4 shows the forecast of residential and C&I electricity consumption through 2036. Total electricity demand is projected to increase from 5,586 GWh in 2017 to 6,628 GWh in 2036, with almost proportional increases in residential and C&I consumption. Residential consumption increases 6% to 2,476 GWh in 2036, while C&I consumption increases 7% to 3,752 GWh in 2036. Table 3. 2017-2036 ENO Electricity Consumption Forecast by Sector (GWh) shows the ENO's tabular load forecast. Figure 4 shows ENO's load forecast in tabular form.

Figure 4. 2017-2036 ENO Electricity Consumption Forecast by Sector
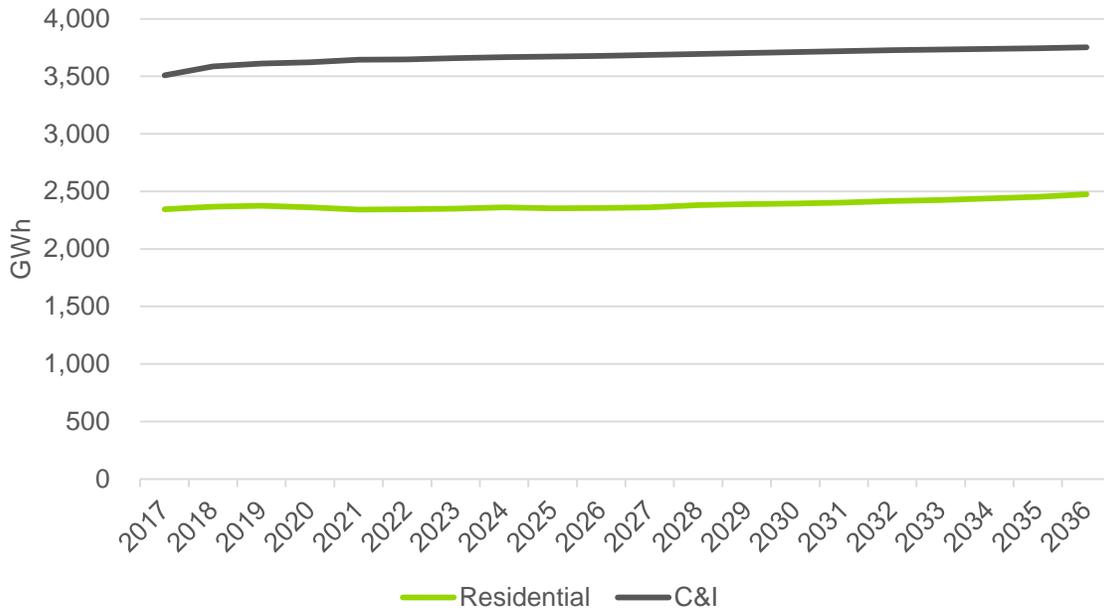
Source: ENO Load Forecast

Table 3. 2017-2036 ENO Electricity Consumption Forecast by Sector (GWh)

Sector	2017	2020	2025	2030	2036
Residential	2,346	2,361	2,354	2,395	2,476
Commercial & Industrial	3,510	3,622	3,671	3,711	3,752
Total	**5,856**	**5,983**	**6,025**	**6,105**	**6,228**

Source: ENO Load Forecast

Measure Characterization

This potential study leveraged the database of electric measures characterized as part of the 2015 Arkansas Energy Efficiency Potential study. In 2015, Navigant conducted an Arkansas-wide study of energy efficiency potential for the seven investor-owned electric and gas utilities in Arkansas, including Entergy Arkansas, Inc. The 2015 study used the Arkansas Technical Reference Manual (TRM) to specify the effective useful life (EUL) and calculations for energy savings for each measure listed in the TRM. Navigant developed estimates of implementation costs, measure density, baseline density and technical applicability in addition to calculating per unit savings based on the TRM. This ENO analysis differs from the 2015 study in that it captures electric-only impacts. This study also assumes that gas savings do not impact the cost-benefit evaluation of measures (i.e. if implementation of an electric measure increases or decreases gas use).

Information regarding the allocation of end use energy, energy intensities, the existing saturation of energy-efficient devices, etc. required to estimate the EE potential for each measure was derived from a variety of sources. The Arkansas measure-assumptions serve as a basis for this study given the relatively

few changes in technology performance or measure costs since the 2015 study. In cases where changes to measure inputs have occurred, Navigant updated the underlying measure assumptions to reflect those changes. Similarly, where ENO-specific information was available, such as penetration of electric space heating, heat pumps, and space cooling, Navigant used these specific ENO inputs. The following list details specific adjustments made to the modeled measures to reflect 2017 data and ENO territory characteristics:

- All costs assumptions for LED measures were updated to reflect declines in technology costs.

- LED baseline technologies through 2020 are assumed to be EISA compliant. 2020 and beyond, baseline wattages are at CFL levels.

- All CFL and standard T8 fluorescent retrofits have been removed.

- All high bay lighting retrofits are LED.

- LED lamp and fixture retrofit options have been added.

- Home energy reports have a higher technical applicability than the Arkansas study.

- Duct sealing savings have been updated based on the Evaluation of PY5 Energy Efficiency Programs Portfolio, July 2016 report submitted by ADM Associates, Inc.

- Smart thermostat saturation levels have been reduced, indicating higher technical potential for this measure than the Arkansas study.

- Baseline saturation levels have been modified (percent of eligible stock that are at baseline conditions – i.e. are not retrofitted) for ceiling insulation, wall insulation, and central air conditioners by 20% to adjust for higher efficiency conditions because of re-construction post-Katrina. See Appendix A for more details.

The measure characterization consisted of estimating and defining key parameters across the various residential and C&I customer segments and inputting them into the **DSMSim™** model to calculate the various potential scenarios. Navigant defined the parameters as follows:

1. **Measure Description:** Qualitatively indicates the EE action that is being performed by this measure.

2. **Baseline Assumption**: The baseline technology (base) characterized per the Arkansas TRM or Navigant's engineering assumptions. The base represents existing technology.

3. **End-Use, Sector and Segment Mapping:** These parameters facilitate the mapping of each measure to the appropriate end uses, sectors, and customer segments.

4. **Measure Lifetime:** The lifetime in years for the base and EE technologies. The base and EE lifetime only vary in instances where the two cases represent inherently different technologies, such as LED or CFL bulbs compared to a baseline incandescent.

5. **Measure Costs:** The base (existing or code-based) and EE material and labor costs are used as inputs for the incremental measure costs.

6. **Annual Energy Consumption:** The annual energy consumption in kilowatt-hours (kWh) for each of the base and EE technologies.

Approach to Achievable Potential Scenarios

This section describes the three achievable potential scenarios included in this study.

Scenario 1: High Case Achievable Potential

The High Case Achievable Potential scenario represents Navigant's best judgment regarding a level of EE potential that would be achievable with an aggressive roll-out of EE programs. The modeled measures cover a broad array of efficiency measures in existence today, adjusting for some known technology cost and efficiency advancements across the residential, commercial, and industrial sectors. It assumes aggressive, yet realistic, levels of program marketing of both hardware and behavioral measures, in addition to a comparatively high level of incentives. It further assumes that all measures are screened for cost effectiveness using a total resource cost (TRC) test. [7,8] A summary of key modeling assumptions is provided below.

- TRC >= 1.0 at the measure level. Overall portfolio is also cost effective.

- Incentives cover ~60% of a measure's total incremental cost.

- High, yet realistic, assumed program marketing effectiveness.

- Administrative costs on a $/kWh basis are roughly in line with historic levels.

- Includes known measures in existence today.

Scenario 2: High Case Theoretical – Known Measures

The High Case Theoretical – Known Measures scenario represents a theoretical level of potential under a set of conditions that may not be realistic. This theoretical scenario yields a 2.0%/year annual incremental savings potential as a percentage of utility sales in at least one year of the simulation horizon. To model the potential of this scenario, the requirement for measure-level cost effectiveness was reduced to a TRC >=0.3. To generate a fast adoption profile over time, the program marketing effectiveness values are higher than realistic. Further, this scenario assumes all incentives cover 100% of incremental measure cost, which is also higher than realistic. Similar to the High Case Achievable Potential scenario, this scenario only includes measures known to be in existence today. A summary of key modeling assumptions is provided below.

- TRC >= 0.3 at the measure level.

- Incentives cover 100% of a measure's total incremental cost.

- Very high program marketing effectiveness.

- Administrative costs are ~50% higher than historic administrative costs, due to the increased marketing requirements.

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[7] The total resource cost test, TRC, is a benefit to cost ratio that includes the benefits and costs from the perspective of all customers in a utility service territory. The benefits are typically the avoided energy and capacity costs (sometimes other benefits are included) and the costs are the program costs (not including incentives) plus the incremental measure costs.
[8] "Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers" Nov 2008, https://www.epa.gov/sites/production/files/2015-08/documents/cost-effectiveness.pdf

- Includes measures known to be in existence today.

Scenario 3: High Case Theoretical – Known and Unknown Measures

The High Case Theoretical – Known and Unknown Measures scenario is identical to Scenario 2 with the exception that the incremental savings as a percentage of sales is assumed to be held at 2.0%/year after 2024, the year in which Scenario 2 reaches 2.0%. In Scenario 2, the simulated model output shows a marked decline in incremental annual potential due to saturation of the market for efficiency technologies. Scenario 3 holds the incremental savings level constant. This analysis does not postulate specific measures that would account for the difference between Scenario 2 and Scenario 3; as such, it is assumed that some set of measures unknown now would be introduced at the same incremental cost as simulated in 2023, escalated only for inflation.

A summary of key modeling assumptions is provided below.

- TRC >= 0.3 at the measure level.

- Incentives cover 100% of a measure's total incremental cost.

- Very high program marketing effectiveness.

- Administrative costs are ~50% higher than historic administrative costs, due to the increased marketing requirements.

- Includes known measures in existence today and unknown measures not currently on the market but presumed to be potentially available in the future. The unknown measure costs equal the costs seen in 2023, the year in which incremental annual potential peaked in Scenario 2, and are escalated for inflation.

4. RESULTS

The following section outlines the results of the efficiency potential analysis. The following section include results for the three separate scenarios, as described in Chapter 3:

- Scenario 1: High Case Achievable

- Scenario 2: High Case Theoretical – Known Measures

- Scenario 3: High Case Theoretical – Known and Unknown Measures

Figure 5 provides an estimate of the incremental annual potential as a percentage of unadjusted forecast sales[9] in the absence of efficiency programs from 2017 – 2036 for each scenario, which are described in detail in the subsequent sections.

Figure 5. Electric Incremental Potential as Percentage of Forecasted Electric Sales 2017 – 2036
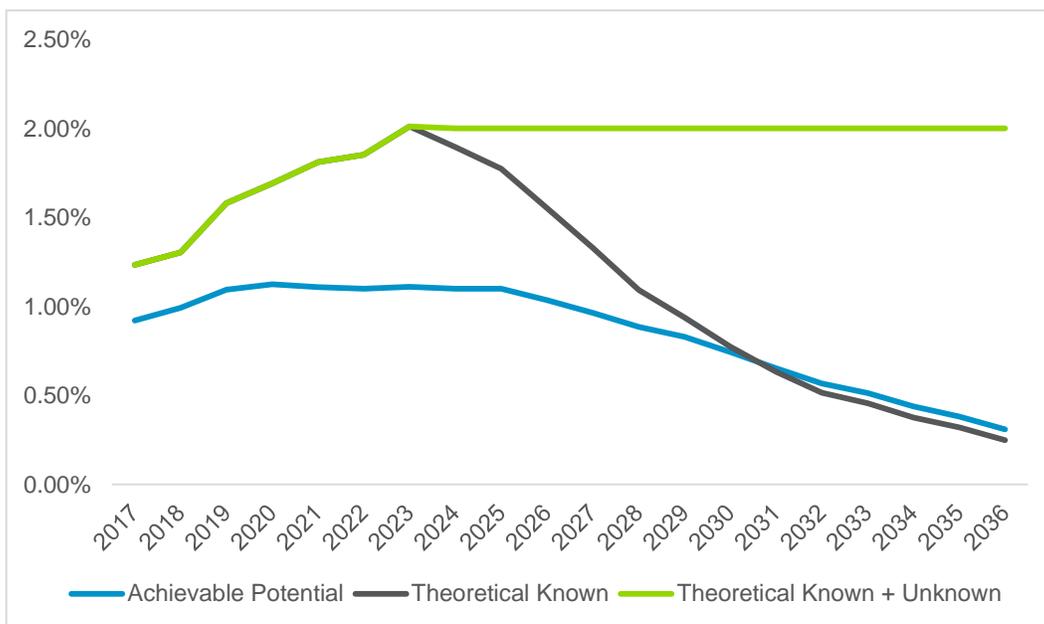
Scenario 1: High Case Achievable Forecast

The High Case Achievable Potential Forecast represents Navigant's best judgment regarding a level of EE potential that would be achievable with an aggressive roll-out of EE programs.

Table 4 shows the high case achievable results by sector, cumulatively and incrementally by year. In this scenario, we estimate that ENO has the potential to achieve a cumulative savings of 1,057 GWh by 2036,

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[9] Navigant used a fixed forecast which does not change with each increment of efficiency achieved year over year.

or an average annual savings of 53 GWh per year, on a net basis (i.e., accounting for estimate free ridership).

Table 4. Cumulative & Incremental Achievable Potential (GWh/Year)

Year	Cumulative			Incremental		
	C&I	**Res**	**All**	**C&I**	**Res**	**All**
2017	26	28	54	26	28	54
2018	53	61	114	28	32	60
2019	84	96	180	30	36	66
2020	112	136	247	28	39	67
2021	142	172	314	30	36	67
2022	174	206	380	32	34	66
2023	208	240	448	33	34	68
2024	242	274	515	34	33	68
2025	276	305	582	35	31	66
2026	311	334	645	34	29	63
2027	345	360	705	34	26	60
2028	378	384	762	33	24	57
2029	409	405	814	31	21	52
2030	438	423	862	29	18	47
2031	466	439	904	27	15	43
2032	490	452	942	25	13	38
2033	513	463	976	23	11	34
2034	534	472	1006	21	9	30
2035	554	479	1033	19	8	27
2036	571	486	1057	18	7	24

Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.

Values defined as "cumulative potential" represent the accumulation of each year's annual achievable potential. For example, an annual achievable potential of 20 GWh per year results in a cumulative achievable potential of 100 GWh over a 5-year period. The same concept applies to achievable potential results represented as a percentage of sales; an annual achievable potential of 0.9% per year, for ten years, would result in a cumulative achievable potential of 9 percent of forecasted sales. Figure 6 below show the cumulative achievable potential as a percentage of forecasted electric sales for this study. We see below that ENO can reduce forecast sales in 2036 by 17% with a comprehensive set of efficiency programs that are aggressively marketed and incentivized.

Figure 6. Cumulative Achievable Potential by Sector as a Percentage of Forecasted Sales
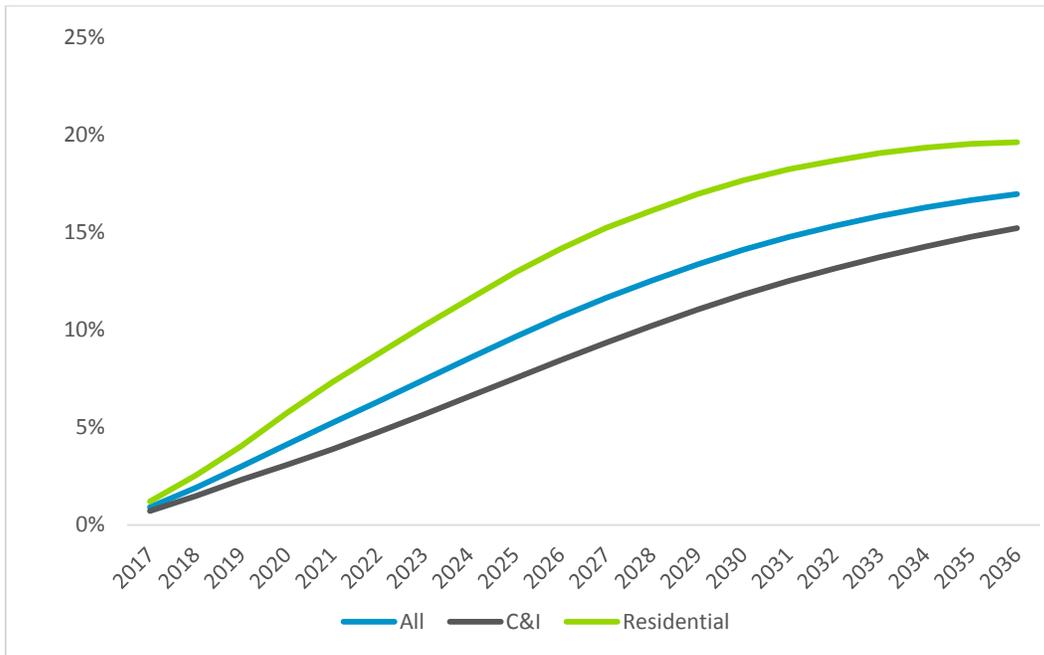
As illustrated above, although C&I has the greater potential in absolute terms, measuring by GWh/year, the residential sector has the greatest cumulative potential savings as a percentage of forecast sales, with an opportunity to reduce forecast sales by ~20% over the study horizon. The high potential for duct sealing, insulation, and air conditioning tune-ups drives this forecasted savings.

Potential savings can also be represented on a yearly basis as "incremental" annual achievable potential. Table 5 and Figure 7 show ENO's incremental achievable savings per year from 2017 – 2036 as a percentage of sales. As seen below, savings potential quickly ramps up to ~1%/year after 2019 and stays slightly above this value for roughly a decade. After ~10 years, incremental annual potential as a percentage of sales tails off due to known measure saturation of the market. In other words, the bucket of potential savings begins to empty, and therefore the rate at which the bucket of savings can be implemented diminishes over time. Given sufficient time, the incremental annual potential would be reduced to zero once all savings were completely harvested, unless replenished by new savings opportunities due to the emergence of new technologies, or introduction of new building stock through new construction.

Table 5. Incremental Achievable Potential as a Percentage of Forecasted Sales

Year	C&I	Res	All
2017	0.73%	1.21%	0.92%
2018	0.76%	1.35%	0.99%
2019	0.83%	1.50%	1.09%
2020	0.76%	1.69%	1.13%
2021	0.81%	1.59%	1.11%
2022	0.88%	1.45%	1.10%
2023	0.90%	1.44%	1.11%
2024	0.92%	1.37%	1.10%
2025	0.94%	1.37%	1.10%
2026	0.92%	1.21%	1.04%
2027	0.90%	1.07%	0.96%
2028	0.87%	0.89%	0.89%
2029	0.82%	0.84%	0.83%
2030	0.77%	0.71%	0.74%
2031	0.70%	0.58%	0.65%
2032	0.64%	0.44%	0.57%
2033	0.59%	0.39%	0.51%
2034	0.54%	0.27%	0.44%
2035	0.49%	0.19%	0.38%
2036	0.44%	0.09%	0.31%

Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.

Figure 7. Incremental Achievable Potential as a Percentage of Forecasted Sales
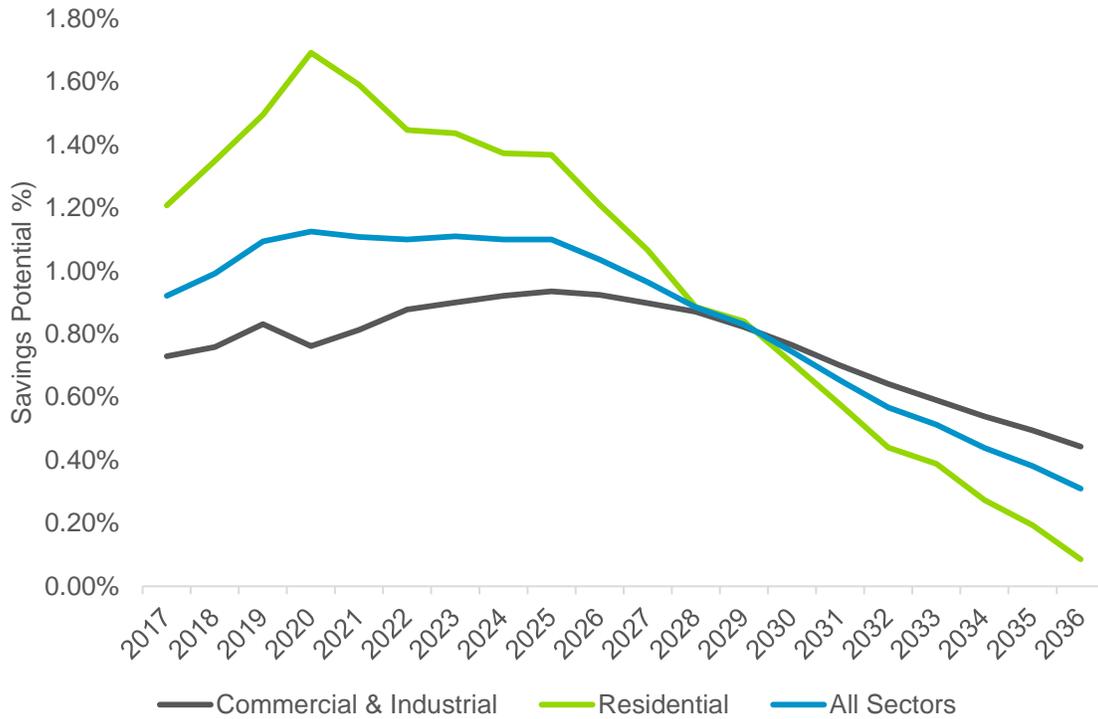
In addition to overall results by sector, the analysis yielded results by measure. The measure with the highest potential was duct sealing in the residential sector, followed by high efficiency new construction and interior 4-ft LED lights, both in the commercial and industrial sector. These measure results are based on the measure characterizations described in Chapter 3, which are consistent with industry standards and benchmarked to ENO program performance in previous years. Figure 8 shows the top 20 achievable potential measures by average annual GWh, a key input into the incremental and cumulative achievable potential results outlined above.

Figure 8. Cumulative Achievable Potential 2017 – 2036 – Top 20 Measures (GWh)

Measure	GWh
Res|Duct Sealing R-8|CZ9B	241
CI | Interior 4 ft LED - ET	114
Com | High Efficiency Comprehensive New Construction Electric	96
Res|Ceiling Insulation R-38 with R-0 base - Gas Heat |CZ9B	60
Com| Computer Power Management	59
CI | Controls Occ Sensor	39
Res|Ceiling Insulation R-38 with R 5-8 base - ER|CZ9B	34
Indust | Compressed Air Measures	31
Res|CAC Tune-up|CZ9B	30
Com | Interior LED High Bay | Replacing HID	28
CI | LED Screw In - Interior	25
Com | Refrigeration Retrofit Measures	24
Res|Ceiling Insulation R-38 with R-0 base - ER|CZ9B	23
Res|Omni Directional LED - General	23
CI | Lighting Density Reduction	23
COM | LED Fixture - Interior	23
Com | Variable Speed Ventilation	19
Res|Home Energy Reports	16
Com | Interior LED High Bay | Replacing T8HO HB	15
C&I|Vending Occ Control	12

Budget

The budget estimate for the high case achievable scenario is presented below in Table 6, which includes an estimate of administration cost as well as incentive costs. Administration costs of $0.135/kWh are slightly higher than historical administrative costs in ENO's service territory due to adjustments for inflation. Incentive costs were calculated based on forecast measure adoption, incremental measure costs, and assumed incentive levels as described in the Chapter 3 scenario sections. Total cost of first year savings in 2017 is ~$0.28/first-year kWh compares favorably (i.e., on the low end) of program costs presented in the Chapter 5. Costs of first-year savings rise to ~$0.45/kWh over the simulation horizon due to inflation and a changing measure mix over time. As noted in Chapter 3, all measures in this scenario are cost effective with a TRC >=1.0. Inclusive of administrative costs, the portfolio is cost effective with a portfolio TRC ranging from ~1.7 to ~2.0 over the simulation horizon.

Table 6. Estimated Budget for High Case Achievable Potential

Year	Administration	Incentives	Total
2017	$7,921,933	$8,415,905	$16,337,839
2018	$8,994,417	$9,502,727	$18,497,144
2019	$10,117,456	$10,575,742	$20,693,198
2020	$10,549,450	$11,693,058	$22,242,507
2021	$10,595,340	$12,009,587	$22,604,926
2022	$10,661,628	$12,608,018	$23,269,646
2023	$11,135,036	$13,405,238	$24,540,273
2024	$11,308,934	$13,546,160	$24,855,094
2025	$11,240,073	$13,337,032	$24,577,105
2026	$10,954,917	$12,914,864	$23,869,782
2027	$10,489,144	$12,226,714	$22,715,858
2028	$10,174,767	$12,317,023	$22,491,790
2029	$9,529,195	$11,733,497	$21,262,691
2030	$8,751,218	$10,818,053	$19,569,272
2031	$7,977,849	$9,940,386	$17,918,234
2032	$7,235,021	$9,071,583	$16,306,604
2033	$6,540,929	$8,279,731	$14,820,661
2034	$5,913,374	$7,579,637	$13,493,010
2035	$5,370,357	$6,957,019	$12,327,376
2036	$4,929,933	$6,461,779	$11,391,712

Scenario 2: High Case Theoretical – Known Measures

The High Case Theoretical – Known Measures scenario represents a theoretical level of potential assuming 100% of incremental costs are covered by incentives, and assuming a program ramp rate that would permit achieving a target of 2.0%/year in at least one year of the simulation horizon (See Chapter 3 for more detailed scenario assumptions). This ramp rate as well as the estimated incremental costs covered by the utility are not considered realistic, though savings and costs estimates are provided in this Chapter as a point of reference. Additionally, this scenario models a lower cost-effectiveness screening level threshold than Scenario 1. As seen in Table 7, incremental annual potential as a percentage of sales tails off after about 2023 due to market saturation of known measures. This rise and subsequent fall of incremental savings is consistent with expectations and is characteristic of typical technology adoption patterns.

Table 7. Incremental Theoretical Known Measures Potential as a Percentage of Forecasted Sales

Year	C&I	Res	All
2017	0.98%	1.62%	1.23%
2018	1.01%	1.75%	1.30%
2019	1.24%	2.10%	1.58%
2020	1.28%	2.33%	1.69%
2021	1.41%	2.46%	1.81%
2022	1.56%	2.31%	1.85%
2023	1.67%	2.54%	2.01%
2024	1.57%	2.40%	1.90%
2025	1.44%	2.32%	1.77%
2026	1.27%	2.00%	1.55%
2027	1.10%	1.69%	1.33%
2028	0.93%	1.31%	1.09%
2029	0.79%	1.17%	0.94%
2030	0.67%	0.93%	0.77%
2031	0.57%	0.73%	0.63%
2032	0.49%	0.53%	0.52%
2033	0.45%	0.46%	0.46%
2034	0.40%	0.31%	0.38%
2035	0.38%	0.21%	0.32%
2036	0.34%	0.07%	0.25%

Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.

Budget

In addition to forecasting potential savings, Navigant estimated the associated administration and incentive costs. The estimated budget reflects the potential savings forecast for this scenario in that costs and savings increase until reaching peak potential and then decrease every year thereafter. Table 8 illustrates these costs and the total budget for each forecast year.

Table 8. Estimated Budget for Theoretical Known Measures Potential

Year	Administration	Incentives	Total
2017	$15,888,700	$43,289,308	$59,178,008
2018	$17,667,699	$47,000,703	$64,668,401
2019	$21,796,146	$56,107,967	$77,904,113
2020	$23,494,153	$61,704,384	$85,198,537
2021	$25,700,886	$69,262,968	$94,963,854
2022	$26,621,758	$73,327,177	$99,948,935
2023	$29,922,060	$81,854,462	$111,776,522
2024	$29,025,058	$81,090,358	$110,115,415
2025	$27,181,798	$76,588,307	$103,770,105
2026	$24,745,803	$70,495,845	$95,241,648
2027	$21,951,653	$63,340,558	$85,292,210
2028	$19,367,559	$57,615,150	$76,982,709
2029	$16,649,166	$50,152,355	$66,801,521
2030	$14,247,172	$43,525,834	$57,773,006
2031	$12,286,922	$38,231,201	$50,518,123
2032	$10,669,987	$33,711,185	$44,381,172
2033	$9,379,602	$29,967,885	$39,347,486
2034	$8,372,842	$26,978,240	$35,351,082
2035	$7,604,282	$24,595,475	$32,199,756
2036	$7,119,074	$23,244,385	$30,363,460

Scenario 3: High Case Theoretical – Known and Unknown Measures

This scenario is similar to Scenario 2 with the exception that the forecast assumes that ENO can maintain its annual percent savings from 2023 onwards through the emergence of unknown technologies at an assumed cost, rather than achieving a declining rate of savings due to market saturation, as described in Chapter 3. Table 9 shows projected savings per year, as a percentage of forecast sales, based on these assumptions.

Table 9. Incremental Theoretical Known & Unknown Measures Potential as a Percentage of Forecasted Sales

Year	C&I	Res	All
2017	0.98%	1.62%	1.23%
2018	1.01%	1.75%	1.30%
2019	1.24%	2.10%	1.58%
2020	1.28%	2.33%	1.69%
2021	1.41%	2.46%	1.81%
2022	1.56%	2.31%	1.85%
2023	1.67%	2.54%	2.01%
2024	1.66%	2.53%	2.00%
2025	1.66%	2.54%	2.00%
2026	1.66%	2.54%	2.00%
2027	1.66%	2.54%	2.00%
2028	1.66%	2.53%	2.00%
2029	1.66%	2.53%	2.00%
2030	1.66%	2.53%	2.00%
2031	1.66%	2.53%	2.00%
2032	1.66%	2.52%	2.00%
2033	1.66%	2.52%	2.00%
2034	1.67%	2.51%	2.00%
2035	1.67%	2.50%	2.00%
2036	1.67%	2.49%	2.00%

Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.

Budget

Based on the measures and assumptions in this scenario, Navigant modeled potential costs. Similar to the potential savings for this forecast, costs do not decrease after the utility has reached its peak potential. Instead, costs continue to increase to account for new, unknown measures, which we assume cost the same as the suite of measures modeled in 2023 (the year of peak modeled savings), escalated

for inflation. Table 10 shows the administrative, incentive, and total costs per year for the High Case Theoretical – Known and Unknown Measures scenario.

Table 10. Estimated Budget for Theoretical Known & Unknown Measures Potential

Year	Administration	Incentives	Total
2017	$15,888,700	$43,289,308	$59,178,008
2018	$17,667,699	$47,000,703	$64,668,401
2019	$21,796,146	$56,107,967	$77,904,113
2020	$23,494,153	$61,704,384	$85,198,537
2021	$25,700,886	$69,262,968	$94,963,854
2022	$26,621,758	$73,327,177	$99,948,935
2023	$29,922,060	$81,854,462	$111,776,522
2024	$30,048,385	$82,200,035	$112,248,420
2025	$30,641,147	$83,821,588	$114,462,735
2026	$31,302,153	$85,629,828	$116,931,982
2027	$31,999,000	$87,536,115	$119,535,115
2028	$32,786,703	$89,690,945	$122,477,648
2029	$33,525,264	$91,711,347	$125,236,611
2030	$34,281,641	$93,780,482	$128,062,123
2031	$35,072,083	$95,942,807	$131,014,890
2032	$35,898,596	$98,203,807	$134,102,404
2033	$36,702,269	$100,402,326	$137,104,595
2034	$37,548,643	$102,717,657	$140,266,300
2035	$38,422,994	$105,109,524	$143,532,518
2036	$39,378,923	$107,724,552	$147,103,475

5. BENCHMARKING THE RESULTS

As part of this study, Navigant benchmarked the achievable energy efficiency potential results relative to regionwide achievable potential, actual savings, and actual savings costs. Navigant also benchmarked these figures against leading regions, states, and utilities for a comprehensive comparison. The analysis leveraged recent potential studies as well as data from two leading energy institutions, the American Council for an Energy-Efficient Economy (ACEEE), a non-profit advocacy group, and the US Department of Energy's Energy Information Administration (EIA). In doing so, Navigant sought to contextualize the study's results within the region, determining broader trends in the regional area and across the country. For comparison purposes, all savings figures are presented as a percent of electric sales. Table 11 shows the data and studies used in this benchmarking analysis.

Table 11. ENO EE Benchmarking Analysis Sources

Information Type	Source
Achievable Potential Studies	• 2015 Navigant Study – Arkansas Energy Efficiency Potential Study • 2015 ICF International Study – Long-Term Demand Side Management Potential in the Entergy New Orleans Service Area • 2013 ACEEE Study – A Guide to Growing an Energy-Efficient Economy in Mississippi • 2013 ACEEE Study – Louisiana's 2030 Energy Efficiency Roadmap • 2011 Global Energy Partners Study – Tennessee Valley Authority Potential Study • 2007 ACEEE Study – Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs
Actual Savings Data	• 2015 ACEEE Spending and Savings Table • 2010 ACEEE Spending and Savings Table

Actual Portfolio Cost Data	• Navigant Data • 2016 Mississippi Public Service Commission Working Session – Energy Efficiency in Mississippi • 2015 ACEEE Spending and Savings Table • 2015 Frontier Associates – Energy Efficiency Accomplishments of Texas Investor Owned Utilities Calendar Year 2015 • Derived from EIA Form 861 – Electric Power Sales, Revenue, and Energy Efficiency Form EIA 861 Detailed Data Files

Review of Entergy New Orleans EE Accomplishments

In 2015, ICF International completed a demand side management (DSM) potential study, spanning 2015 – 2034 for ENO territory. The study estimated that ENO had a cumulative achievable potential of 3.9% - 10% savings over the study horizon, depending on incentive levels.[10] This equates to an average annual savings of 0.3% - 0.5%. The ICF study came to this conclusion using a bottom-up approach, aggregating baseline data, measure data, and program data. The low case achievable potential defined by ICF aligns closely to ENO's actual savings in 2015. In ENO's most recent Energy Efficiency Programs Portfolio Evaluation from project year five, the utility realized 0.4% in actual savings.[11]

Market Potential Savings Benchmark at the State-Level

Navigant compared this study's results against other recent potential studies. The team conducted a comprehensive review of potential studies, specifically focusing on achievable potential from surrounding states for a regionwide comparison. The studies researched provided data on cumulative savings throughout the next decade. Since the Navigant ENO study defines achievable potential on an annual basis, the research team determined the average savings per year for comparison. Figure 9 shows average annual future savings potential over a 15-year timeframe for the 6-state region surrounding the ENO territory. The figure also illustrates that Navigant's achievable potential estimate aligns to regionwide expectations. It is important to note that the achievable savings reported below (Figure 9) reflect an average of cumulative savings over the study period.[12]

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[10] ICF International, "Long-Term Demand Side Management Potential in the Entergy New Orleans Service Area," June 23, 2015.
[11] ADM Associates, "Evaluation of PY5 Energy Efficiency Programs Portfolio," July 2016.
[12] To determine annual percent savings, we divided the total percent savings by the study period.

Figure 9. Average Achievable Potential Savings Per Year as a Percentage of Sales in the South
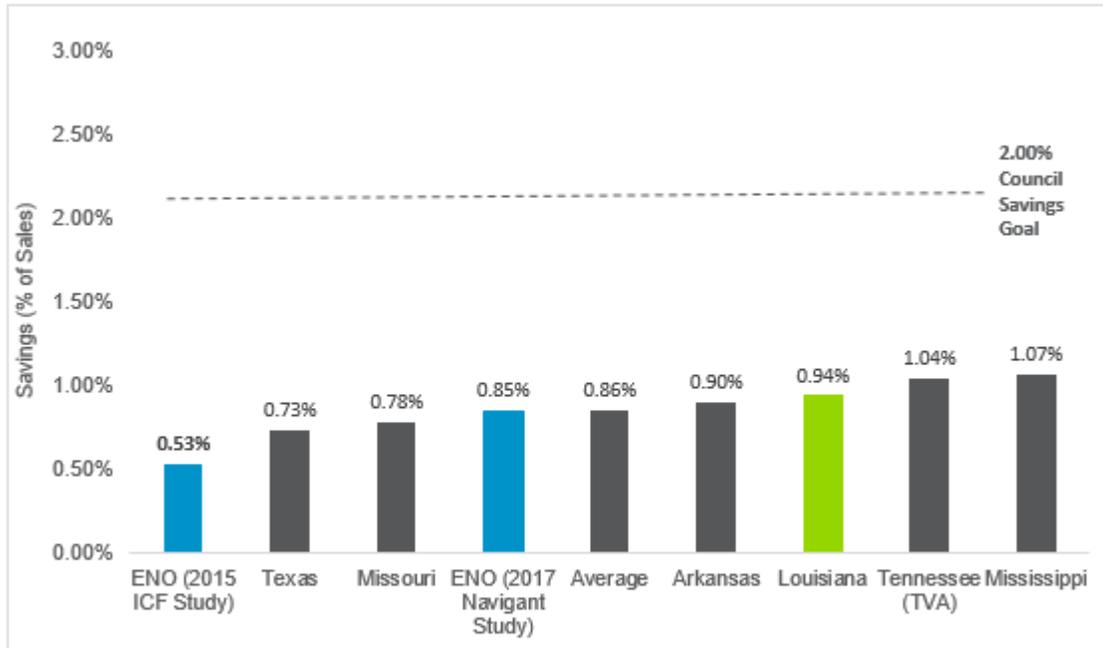
Actual Savings Benchmark at the State-Level

In addition to evaluating the future potential for energy efficiency, Navigant also researched actual accomplished energy efficiency savings at the state-level to determine regionwide trends. The research team examined states surrounding ENO as well as high-performing states in other regions. The differences in actual savings across the country likely relates to differing program maturities, policies, retail rates, energy efficiency costs, energy efficiency spending, and other factors. This specific portion of the benchmarking aimed to verify how closely actual savings reflected achievable potential. Navigant used the most recent data from the EIA and ACEEE to derive this information. Figure 10 shows actual savings by state and region, including the 2015 median actual savings across the US of 0.61%.

Figure 10. 2015 Actual Accomplished Net Savings by State
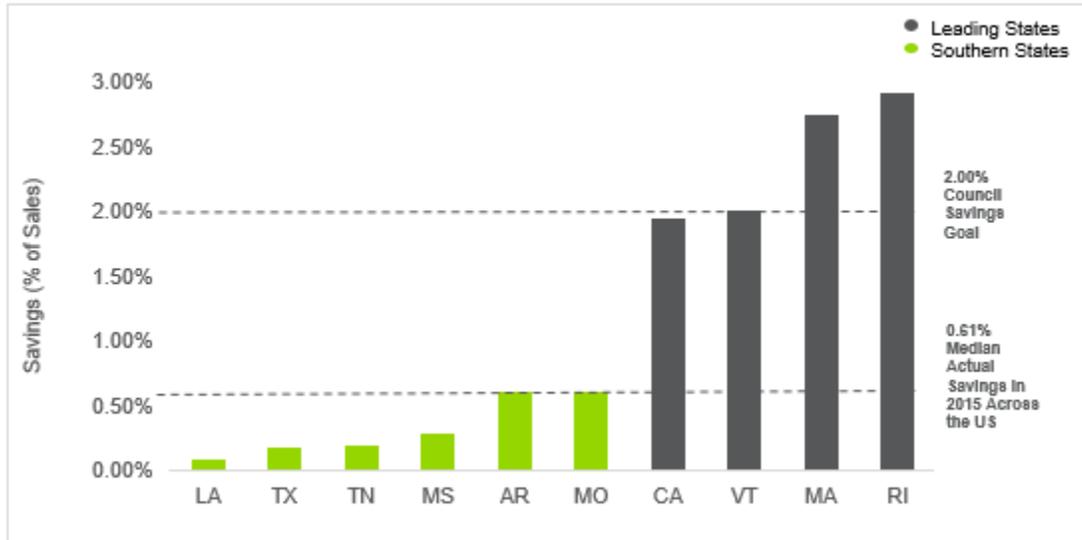
Figure 10 illustrates that utilities do not necessarily achieve their achievable potential; achievable potential only loosely predicts actual savings. For example, Arkansas and Missouri accomplished savings of .61%, which is below the lowest achievable potential averages of 0.73% for the region. Additionally, Texas accomplished 0.18% in actual savings, compared to its achievable potential of 0.73% (Figure 9).

Additionally, one year of savings data does not guarantee that utilities will have consistent yearly savings at this level. For instance, Vermont achieved 2.32% savings in 2010 and 2.01% in 2015, demonstrating that savings may fluctuate. Also, California achieved 1.79% savings in 2010 and 1.95% savings in 2015, showing that achieving a stable 2% savings solely through EE measures can be challenging even in states with leading energy efficiency programs for the past 30 years.

Actual Savings and Cost of Savings Benchmark at the Utility-Level

Navigant also benchmarked actual savings and EE program expenditures at the utility-level to further examine the accuracy of achievable potential, determine key trends, and identify potential savings constraints. This process involved aggregating key data from local investor-owned utilities and nationwide peers with industry-leading energy efficiency programs. Figure 11 shows actual spending and saving from different utilities across the country.

Figure 11. 2015 Actual Spending and Savings by Utility
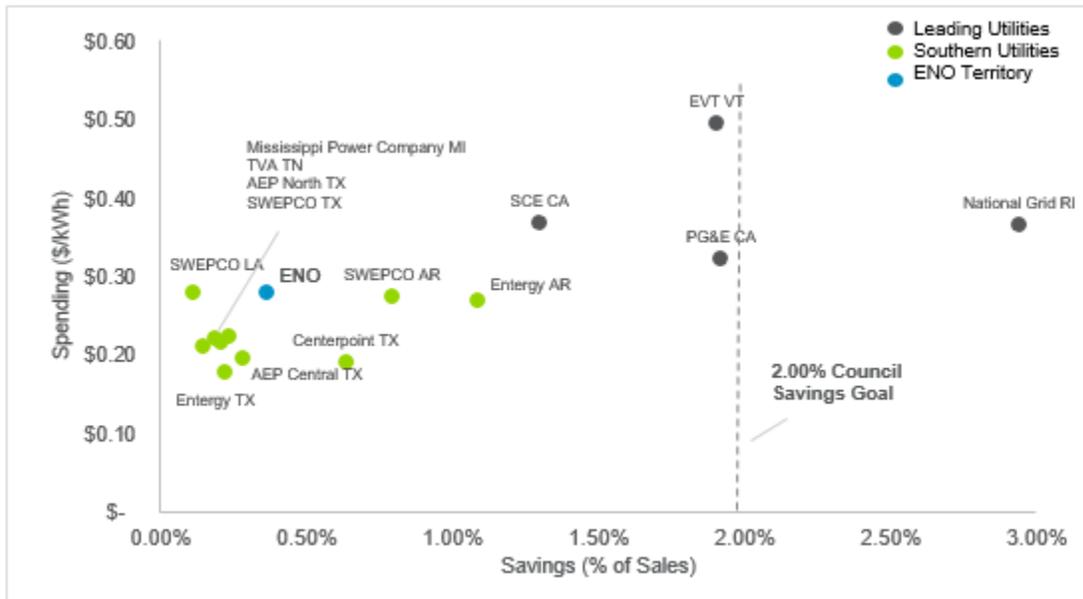
As illustrated by the figure above, utility level energy efficiency savings tend to reflect statewide achievable potential and actual savings. More specifically, utilities in the South generally achieved less than 1% savings in 2015. The exception to this group is Entergy Arkansas which achieved a savings of 1.1%, more than the expected achievable potential and the actual savings of Arkansas. Those in leading energy efficiency states follow similar trends with utilities achieving roughly 1.5 – 3% savings in 2015, similar to statewide actual savings (Figure 11).

In terms of costs, the figure demonstrates that utilities with higher energy efficiency savings tend to spend more on a $/kWh basis than utilities with lower savings. The correlation indicates that percent kWh savings partially depends on the $/kWh a utility is willing to spend, and therefore, costs may be partially dependent on actual kWh savings. A recent 2014 study by the South-central Partnership for Energy Efficiency as a Resource (SPEER) came to a similar conclusion after comparing per capita (rather than $/kWh) energy efficiency spending by state.[13] The study also noted that budget may limit incentives and advertising for energy efficiency programs, which in turn limits savings. Another 2010 study by Georgia Tech and Duke University, specifically cited legislation as a limitation to achieving high energy efficiency savings in the South.[14] Additionally, electricity rates vary across regions and therefore, may also affect spending, potential achievable savings, and actual savings, since certain measures may not be as cost effective in some locations. Many other factors, including regional labor rates, specific regional infrastructure (e.g. nonprofit and community leader support) and an existing contractor network

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[13] South-central Partnership for Energy Efficiency as a Resource (SPEER), Energy Efficiency as a Resource in Texas, August 2014, https://eepartnership.org/wp-content/uploads/2015/07/energy-efficiency-as-a-texas-resource-whitepaper-for-speer-commssion-august-2014.pdf.
[14] Georgia Tech & Duke University, Energy Efficiency in the South, April 12, 2010, https://nicholasinstitute.duke.edu/sites/default/files/publications/energy-efficiency-in-the-south-paper.pdf.

supporting EE installations, impact EE savings and costs. These studies and the figures above illustrate the myriad factors that can influence energy efficiency savings.

APPENDIX A. MODEL GLOBAL ASSUMPTIONS

Table 12 shows a selection of key global assumptions used in the analysis of energy efficiency for ENO. The significance of these global assumptions is that they serve as key financial and valuation parameters (e.g., inflation and discount rates, avoided costs, etc.) used in the calculation of economic and achievable potential.

Table 12. Global Assumptions

Assumption	Value
Inflation Rate (%/year)	2%
Discount Rate (%/year)	7.427% nominal, for all Cost Tests
Avoided Costs	Electric energy: $37/MWh (2017 $)
	Generation capacity: $75/kW-yr (2017 $)
Line Losses	Total Retail Average: 6.24%

Source: ENO

Stock Forecast

One of the key global inputs used in Navigant's DSMSim is a forecast of residential and C&I stock. Residential stock is measured in residential accounts while C&I stock is measured through floor space (e.g., 1000 square feet of floor area).

Residential Stock Forecast
Navigant developed the residential stock forecast based on ENO's forecast of residential accounts from 2017 through 2036. The table below shows the residential stock in 2017 and 2036. Residential stock increases from 180,129 accounts in 2017 to 197,926 accounts in 2036.

Commercial Stock Forecast
Navigant developed the commercial floor space stock based on ENO's C&I electricity consumption and electricity-intensity estimates (kWh/sq. ft.) from the Commercial Building Energy Consumption Survey (CBECS). Navigant divided ENO's C&I consumption (3,510 GWh) by the CBECS electricity intensity (18.6 kWh/sq. ft.), to determine a 2017 floor space stock of 189 million sq. ft. To project the forecast of C&I stock through 2036, Navigant analyzed historical employment levels in New Orleans using data from the New Orleans Regional Council for Business Economics (NORCBE).[15] Historical employment levels indicate commercial and industrial economic activity, as well as electricity and natural gas demand. Navigant used the five-year historical employment levels from 2012 to 2016 to determine an average annual growth rate of 1.1% per year, applying the rate to the 2017 stock to forecast C&I stock through

---

[15] NORCBE. New Orleans Regional Economic Index (April 2017). Table 11. Available at:
http://www.norcbe.org/images/THE_NEW_ORLEANS_REGIONAL_RECOVERY_INDEXMARCH_2017.pdf

2036. Table 13 shows the C&I stock in 2017 and 2036, with stock increasing from 189 million sq. ft. in 2017 to 232 million sq. ft. in 2036.

Table 13. Stock Forecast – Residential and C&I

Sector	Units	2017	2036
Residential	# of accounts	180,129	197,926
C&I	million sq. ft.	189	232

Source: ENO data, and Navigant analysis

Katrina Effect

The report refers to the "Katrina effect" as the impact of Hurricane Katrina on the mix of customer end-use equipment; specifically, the increased adoption of high efficiency equipment in the post-Katrina period due to the significant proportion of stock that sustained severe damage during the storm.

Navigant quantified the Katrina effect based on data obtained from three different reports and presentations by the U.S. Department of Housing and Urban Development (HUD).[16, 17, 18] Quantifying the impact of Katrina on the mix of end-use equipment is difficult for several reasons.

- Different studies report various estimates of destroyed, damaged, and/or repaired stock due to differing methodologies, study areas, and dates of reference. The date of reference is also important because some studies may be based on data recorded following other non-Katrina storms (e.g., the compounded impact of Katrina, Rita, etc.).

- Property damage is measured based on a qualitative scale of damage, which introduces a certain degree of bias (e.g., "minor", "major", and "severe" damage).

- Each energy efficiency measure is unique and the likelihood that a given measure – for example, a refrigerator, roof insulation, or a central AC system – might be upgraded is subject to the likelihood that a home experienced flooding and/or wind damage.

Given these challenges in quantifying the Katrina effect, Navigant estimated the fraction of existing stock with high efficiency equipment based on two criteria (1) stock that experienced severe or major damage, and (2) stock that experienced both flooding and wind-damage. Navigant also calculated the fraction of existing stock was destroyed and later rebuilt. Navigant added these two estimates (damaged & repaired stock, and destroyed & rebuilt stock) and applied it to the measure-penetration assumptions used in the

---

[16] HUD. December 2010. Housing Recovery in the Gulf Coast Phase I: Results of Windshield Observations in Louisiana, Mississippi, and Texas. Available at:
https://www.huduser.gov/Publications/pdf/Housing_Recovery_in_the_Gulf_Coast_PhaseI_v2.pdf
[17] HUD. July 2011. American Housing Survey. Components of Inventory Change and Rental Dynamics: New Orleans 2004-2009. Available at:
https://www.huduser.gov/portal/datasets/cinch/cinch09/neworleans_CINCH_Report_04_09.pdf
[18] HUD. September 2010. American Housing Survey: Preliminary Findings from the 2009 New Orleans Metropolitan Survey. Available at: https://www.huduser.gov/portal/pdf/hsg_mrkt/Chi_AHSPresentation.pdf

study. For example, if the Katrina effect was estimated as 20% of existing stock, the new penetration of the base efficiency AC system was decreased by 20%, and the penetration of energy efficient AC systems was increased by 20%.

Table 14 shows the calculations used to estimate the Katrina effect. Navigant determined the Katrina effect to represent 20% of existing stock. This estimate is based on the calculation that 18.5% of existing stock was damaged and later repaired, and that 1.7% of existing stock was destroyed and later rebuilt.

Table 14. Calculation of Katrina Effect

Parameter	Stock (# properties)	Calculation/Source
(1) Properties with Major or Severe Damage	79,925	-
(2a) Properties with Flood and Wind Damage	82%	-
(2b) Properties with inferred repairs/rebuilding	64%	-
(3) Total Damaged Stock	41,748	(1) x (2a) x (2b)
(4) Estimate of Katrina-Only Impact (excl. other storms)	80%	-
(5) Damaged/Repaired Stock (Katrina-driven estimate)	**33,398**	(3) x (4)
(6) 2017 Stock	180,129	-
(A) Percent of Damaged/Repaired Stock	**18.5%**	(5) / (6)
(7) Percent of Stock Destroyed and Rebuilt (Estimate #1)	1.9%	*HUD, Sep 2010*
(8) Percent of Stock Destroyed and Rebuilt (Estimate #2)	1.5%	*HUD, July 2011*
(B) Percent of **Destroyed/Rebuilt Stock**	**1.7%**	[(7) + (8)] / 2
Katrina Effect (% of 2017 Stock)	**20.2%**	**(A) + (B)**

Source: Navigant analysis of HUD data

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

JONATHAN E. LONG

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

PUBLIC VERSION

JULY 2017

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

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TABLE OF CONTENTS

EXHIBITS

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   **I.   INTRODUCTION AND PURPOSE**

2   Q1.   PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

3   A.   My name is Jonathan E. Long. My business address is 639 Loyola Avenue, New

4   Orleans, Louisiana 70113.

5

6   Q2.   ARE YOU THE SAME JONATHAN LONG THAT FILED DIRECT TESTIMONY

7   IN THIS DOCKET?

8   A.   Yes.

9

10   Q3.   ON WHOSE BEHALF ARE YOU FILING THIS DIRECT TESTIMONY?

11   A.   I am testifying before the Council of the City of New Orleans ("CNO" or the

12   "Council") on behalf of Entergy New Orleans, Inc. ("ENO" or the "Company").

13

14   Q4.   WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

15   A.   My Supplemental and Amending Direct Testimony ("Supplemental Testimony")

16   supports the Supplemental and Amending Application in this proceeding, which

17   seeks, among other things, approval to proceed with a project to construct New

18   Orleans Power Station ("NOPS"), which will consist of either a combustion turbine

19   ("CT") resource with a summer capacity of 226 MW, or alternatively, seven Wärtsilä

20   18V50SG reciprocating internal combustion engines ("RICE") (the "Alternative

21   Peaker").

1   My Supplemental Direct Testimony will largely focus on the Alternative

2   Peaker option,[1] as many of the details regarding the original CT that are discussed in

3   my original Direct Testimony (*e.g.*, technology, engineering, procurement and

4   construction ("EPC") contractor, EPC Agreement terms, *etc.*) remain the same.

5   There are, however, several changes to the original CT's cost estimate and timeline

6   that will be addressed herein, such as escalation and increased transmission costs

7   related to the project.

8   Regarding the Alternative Peaker, I provide an overview of the alternative

9   project, explain how it was selected, and how its cost estimate was developed. I then

10   present the current cost estimate and schedule. Next, I provide an overview of the

11   project management approach that the Company intends to employ.

12

13   **II.   PROJECT OVERVIEW**

14   Q5.   PLEASE PROVIDE A BRIEF OVERVIEW OF THE NOPS PROJECT.

15   A.   In its June 2016 Application, the Company proposed to construct a 226 MW

16   (nominal) CT using one Mitsubishi Hitachi Power Systems America 501 GAC CT,

17   which is still an alternative for the Council's consideration. The Company is now

18   also proposing an Alternative Peaker, which as mentioned above, would include

19   seven Wärtsilä RICE generator sets. The Alternative Peaker, if approved by the

20   Council, would be located in New Orleans, Louisiana, within the site boundaries of

---

[1]   It should be noted that to the extent possible, I have attempted to streamline my Supplemental Direct by not
addressing concepts that were addressed in my original Direct Testimony (*i.e.,* insurance, definition of EPC
contractor, the Company's management approach to construction, *etc.*).

1   the deactivated Michoud facility. The base elevation of the unit will be 3.5 feet above

2   sea level, which includes an allowance for a flooding event similar to Hurricane

3   Katrina in the design of the power block elevation. Moreover, as more fully stated

4   below, the unit will be protected by the levees along the Intracoastal Waterway and

5   the Lake Borgne surge barrier constructed/improved after Hurricane Katrina.[2]

6   The Alternative Peaker would be constructed by Burns and McDonnell

7   ("B&M") under a fixed price, fixed schedule form of EPC contract at an estimated

8   cost of $210 million, or roughly $1,640 per kW, including the costs to interconnect to

9   the switchyard. If there are no unanticipated project delays due to the inability to

10   obtain necessary regulatory approvals and permits, or procure materials and

11   equipment, the Alternative Peaker would be expected to enter service in October

12   2019.

13

14   **II.   UPDATE TO ORIGINAL CT COST ESTIMATE AND TIMELINE**

15   Q6. IS THE COMPANY STILL PROPOSING THE ORIGINAL UNIT, A 226 MW CT?

16   A.   Yes. The Company is proposing that the Council select the originally proposed CT

17   based on benefits discussed by Company witnesses Seth E. Cureington and Charles

18   W. Long.   To be clear, if the Council selects this option, Chicago Bridge and Iron,

19   Inc. ("CB&I") would still be the EPC contractor that constructs that unit. Please refer

---

[2]   For a full discussion of the risk mitigation measures put in place following Hurricane Katrina by the Army
Corps of Engineers ("Corps") designed to protect New Orleans East from 100-year storm events, please see
11/18/16 Supplemental Direct Testimony of Jonathan E. Long, at 16-22.

1   to my direct testimony for details related to the Company's EPC agreement with

2   CB&I.

3

4   Q7.   HAVE THE PROJECT TIMELINE AND COST ESTIMATE RELATED TO THE

5   CT BEEN AFFECTED BY NOTICE TO PROCEED NOT BEING ISSUED AS

6   ANTICIPATED?

7   A.   Yes.   As explained in my original testimony, a construction project like NOPS

8   represents a substantial undertaking, and the Company lacks the in-house capability

9   necessary to execute the engineering, procurement and construction for such a

10   project.   Engaging an EPC contractor who can perform all of these functions under a

11   single contract is cost effective and common within the power industry for such

12   projects.   EPC Contractors like CB&I, however, experience normal market pressures

13   just like any other company, and cannot hold a contract open for an indeterminate

14   amount of time at a locked-in price given the demand for its resources and

15   inflationary pressures in the market.   As such, EPC Agreements routinely employ

16   escalation provisions to account for inflationary pressures should construction not

17   begin on a specified date.   This practice is reasonable and standard.

18   In this instance, the EPC Agreement with CB&I agreement provided a fixed

19   price and fixed schedule duration, provided that Notice to Proceed ("NTP") was

20   issued on or before ███████████.   The Company noted in its original

21   Application that if NTP was not issued by that date, the EPC contract price was

22   subject to escalation.   The costs associated with escalation will be $3.1 million,

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

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1   assuming NTP is given by January 2018. The Company also noted that if NTP is not

2   issued by ▮▮▮▮▮▮▮▮, the EPC contract price is open to renegotiation.

3

4   Q8.   ARE THERE ANY ADDITIONAL INCREASES COMPARED TO THE CT'S

5   ORIGINAL ESTIMATE?

6   A.   Yes. There are additional costs of approximately $2.9 million associated with

7   Entergy payroll, expenses, indirect loaders and non-EPC engineering services. There

8   is an estimated $3.1 million for Allowance of Funds Used During Construction

9   ("AFUDC") costs associated with the delay and there is approximately $6.9 million

10   of increased cost for transmission interconnection. It should be noted, however, that

11   while the increase in transmission includes some escalation, it also includes an

12   increase in scope. The original estimate assumed a similar breaker configuration that

13   was used for the recently retired Michoud units. New transmission standards require

14   a different breaker configuration to allow for a greater level of reliability. There is

15   also a need to replace existing structures and build out the existing switchyard on the

16   plant site to support the new interconnection lines.

17

18   Q9.   WHAT IS THE TOTAL INCREASE IN COSTS FOR THE CT PROJECT?

19   A.   The total increase in the overall cost estimate for the CT is $16 million, bringing the

20   overall cost estimate of the CT to approximately $232 million.

21

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

Public Version
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Council Resolution R-07-432 Have Been Redacted

1 Q10. HOW HAS THE ORIGINAL CT'S TIMELINE BEEN AFFECTED BY NOTICE

2   TO PROCEED NOT BEING ISSUED AS ANTICIPATED?

3 A.   As noted in my Direct Testimony, the inability to issue NTP by February 2017

4   resulted in a day-for-day slip in the project's expected date of commercial operation.

5   The original anticipated Commercial Operation Date ("COD") was December 2019.

6   Based on delays to-date, the new anticipated COD assuming the EPC contractor

7   would be given a NTP on or before November 1, 2017 is approximately November

8   2020.

9

10   **III.   SITE CONFIGURATION AND TECHNOLOGY SELECTION**

11 Q11. PLEASE EXPLAIN WHY THE COMPANY HAS PROPOSED SEVEN

12   WÄRTSILÄ RICE ENGINES AS ITS PREFERRED ALTERNATIVE

13   TECHNOLOGY.

14 A.   As discussed by Mr. Cureington, ENO is in need of a peaking resource to meet its

15   capacity, supply role, and reliability needs. Following a recently updated load

16   forecast, my team began to consider a technology with a lower output. The Company

17   engaged WorleyParsons, a qualified engineering firm, to conduct a study regarding

18   the Company's potential options for a smaller resource. As described more fully

19   below, the analysis indicated that the RICE units had the lowest levelized cost of

20   electricity on a $/MWh basis, as well as other benefits such as low water usage, a low

21   emissions profile, the ability to support renewable resources, and the inclusion of

22   black-start capability. Based on these factors, the Company recommends moving

1   forward with proposing the Alternative Peaker as an alternative technology to the

2   Council.

3

4   Q12.   WHAT IS RICE TECHNOLOGY?

5   A.   RICE is a well-known technology used in automobiles, trucks, marine propulsion,

6   and backup power applications. Reciprocating engines use the expansion of hot gases

7   to push a piston within a cylinder, converting the linear movement of the piston into

8   the rotating movement of a crankshaft to generate power. While the steam engines

9   that powered the industrial revolution were driven by externally-produced steam,

10   modern reciprocating engines used for electric power generation are internal

11   combustion engines in which an air-fuel mixture is compressed by a piston and

12   ignited within a cylinder. RICE sizes for power generation range from 4 to 20 MW.

13   In a power plant, multiple spark-ignited or diesel engines are grouped into blocks of

14   engines, called generating sets, to provide modular electric generating capacity in

15   standardized sizes.   Please see Figure 1 for an example of an Engine Hall consisting

16   of RICE engines:

17

1   **Figure 1**

2

3   Q13.   IS THE ALTERNATIVE PEAKER PROPOSED TO BE LOCATED ON THE

4   SAME SITE AS THE ORIGINALLY PROPOSED CT?

5   A.   Yes. The Alternative Peaker is proposed to be located at the Michoud facility in New

6   Orleans, Louisiana.   Figure 2 illustrates the exact location of the Alternative Peaker:

7

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1

Figure 2

2

3

1   Q14.   PLEASE DESCRIBE THE ANALYSIS PERFORMED BY WORLEY PARSONS,

2   WHICH FACTORED INTO THE DECISION TO RECOMMEND THE

3   ALTERNATIVE PEAKER.

4   A. The Company considered the following analysis when selecting the Alternative

5   Peaker:

6   **Table 1**

Equipment Configuration	Net Summer Output (MW)	Heat Rate	Installed Cost[3] ($M)	$/kW	LTSA ($/MWh)	Demin H20 + Aux Cooling (gpm)	Emissions[4], Nox & CO (ppm)	Levelized Cost of Electricity (LCOE)[5] ($/MWh)
Wärtsilä x7 unit	127.6	8,464	120.3	942	5.88	Very Low	5/15	75.45
GE LM6000 PG Sprint x2 units + chiller	106.0	10,425	99.0	1019	3.60	143+159=302	5/15	87.79
GE LM6000 PF Sprint 25 x3 units + evap cooler	121.8	9,732	114.7	1045	4.71	57+0	5/15	85.01
Pratt & Whitney FT-4000 (MHPSA)	108.5	10,013	87.9	903	3.11	105+0	5/15	81.83
M501F3 (MHPSA)	130	11,726	105	805	3.90	Very Low	5/9	88.51

7

---

[3]   These costs are based upon the EPRI PEACE model and are not site specific. It should also be noted that these costs are estimates of non-site specific EPC costs only and are not fully loaded. This analysis was without site specific cost estimates.

[4]   Emissions controls were added to all of the units to achieve the same NOx emissions. The cost of the controls and the aux loads were also included in each configuration which affected the net output and heat rate.

[5]   Based upon 4000 hours per year dispatch and $3.50/MMBtu gas.

1   Q15.   WHAT IS THE EXPECTED OUTPUT OF THE ALTERNATIVE PEAKER?

2   A.   As stated, the Alternative Peaker will be designed to reach a nominal output of

3   approximately 128 MW and a heat rate of roughly ███████ .

4

5   Q16.   WHY IS THE INSTALLED COST FOR THE UNIT IN TABLE 1 LOWER THAN

6   THE COMPANY'S COST ESTIMATE OF $210 MILLION?

7   A.   As stated above, the installed cost used in the analysis conducted by WorleyParsons

8   to help the Company select the Alternative Peaker was not site specific, and

9   represented only EPC costs. Therefore, it can reasonably be expected that all options

10   evaluated would have had higher installed costs once non-EPC costs and site-specific

11   engineering needs were added to the figures listed above.

12

13 Q17.   WHAT DOES A UNIT'S HEAT RATE INDICATE?

14 A.   Heat rate pertains to the fuel required to generate a unit of electricity. The lower a

15   plant's heat rate, the less fuel is required to generate the electricity needed to supply

16   customers. In general, since fuel is a pass-through cost to ENO customers, the lower

17   heat rate of the Alternative Peaker more positively impacts customers than a higher

18   heat rate option.

19

20 Q18.   WHY IS THE ALTERNATIVE PEAKER EXPECTED TO USE LESS GROUND

21   WATER?

22 A.   The Alternative Peaker will require water for multiple uses in the generation process.

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

Public Version
Highly Sensitive Protected Materials Pursuant to
Council Resolution R-07-432 Have Been Redacted

1   These include cooling water makeup to the engines due to evaporation in the

2   generation process, engine turbowashing, water for general plant washdown, and

3   potable water for plant restrooms and faucet use. This technology uses significantly

4   less groundwater than the recently retired Michoud units. The primary water usage

5   for the retired units was associated with steam generation required to power the steam

6   turbine, which was the prime mover for generating electricity. A great deal more

7   water was required to generate this steam than would be necessary for either the

8   RICE or CT technology.

9   Additionally, the retired Michoud units relied on large storage tanks to

10   provide makeup water to address water loss associated with steam generation and

11   other plant needs. The RICE technology also uses less water than the CT technology,

12   which uses most of its water for evaporative cooling purposes during summer months

13   when the air intake to the CT requires cooling prior to that air being presented into the

14   compressor section of the machine.

15

16   Q19. WHY IS THE ALTERNATIVE PEAKER TECHNOLOGY WELL-SUITED FOR

17   SUPPORTING INTERMITTENT RENEWABLE RESOURCES LIKE SOLAR?

18   A.   The RICE units are able to start and achieve full load in a very short period of time,

19   and they are able to start and stop multiple times in a single day. Both of these

20   characteristics are critical to supplying generation when renewable resources are not

21   available (*e.g.*, on cloudy or rainy days or after sunset). The fast start capability is a

22   great option in a peaking or emergency situation. These engines can supply

1   electricity on demand when renewable resources may not be available.   This

2   alternative also allows for partial load operation in the event there is not enough

3   renewable energy available.

4

5   Q20.   WHAT IS BLACK-START CAPABILITY AND HOW IS THIS UNIT MORE

6   BLACK-START CAPABLE THAN ALTERNATIVES?

7   A.   Black-start capability is the ability of the plant to start up under its own power

8   without a backfeed of power from the electric grid.   Typically there is an auxiliary

9   load supplied to the unit from a local switchyard.   In the event of a complete loss of

10   power, the Alternative Peaker will have the ability to supply its own power to start-up

11   and be able to supply power to the grid when needed.   The low auxiliary load

12   requirement for this unit makes the ability to black-start this machine more attractive

13   than other options evaluated because a smaller self-starting generator is required,

14   which has a much lower cost.

15   For example, CT options require higher gas pressure that requires a high

16   auxiliary load.   In the event of an emergency, the gas compressor would have to be

17   started first in order to be able to supply the required gas pressure to the CT.   A

18   typical generator required to black-start a gas compressor would be in the range of 15

19   to 20 MWs, which will require a more costly generator.

20

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Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

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1 Q21. IS THE ALTERNATIVE PEAKER'S CONSTRUCTION COST FIXED AT $210

2   MILLION?

3   A. No. As discussed more fully below, project costs consist of EPC Costs and Non-EPC

4   Costs. The Non-EPC Costs are not fixed. Moreover, while the EPC contract price is

5   fixed assuming the defined scope of work and a timely issuance of full NTP, other

6   factors such as changes in scope due to discovery of new facts, force majeure events,

7   delay in issuing notice to proceed, or changes in law could affect EPC Costs. Those

8   subsequent evaluations could result in change orders that increase or decrease EPC

9   Costs. Also, development projects spanning several years are exposed to a number of

10   risks, both known and unknown, and despite diligent mitigation plans and efforts,

11   scope changes may be required. For example, it would not be unusual that over the

12   long history of the Michoud power plant, a cable for temporary power supply was

13   buried. If that cable is uncovered during excavation, work must stop until it is

14   investigated and ensured to be safe. Any work that the Contractor has to perform

15   related to that discovered cable would be added to the scope of the Project through a

16   change order.

17

18 Q22. WHAT IS THE ASSUMED LIFE OF THE ALTERNATIVE PEAKER?

19 A.   The assumed life for the Alternative Peaker is 30 years.

20

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

Public Version
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Council Resolution R-07-432 Have Been Redacted

1   **IV.   ESTIMATED PROJECT COST AND SCHEDULE**

2   Q23.   WHAT IS THE CURRENT ESTIMATE OF THE COSTS TO COMPLETE THE

3   ALTERNATIVE PEAKER?

4   A.   A summary of the components of the current cost estimate is shown below:

5
6

7

8   Q24.   HOW WERE THESE COST ESTIMATES PREPARED?

9   A.   These estimates are largely derived from the largest single cost component, the EPC

10   agreement with B&M. Following the suspension in the procedural schedule in this

11   docket, the project team, which I lead, was asked to (1) select an alternative

12   technology; and (2) to select an EPC contractor to construct the alternative unit. The

13   Company initiated a competitive process whereby two bidders were asked to submit

14   proposals to perform the EPC work for the Alternative Peaker. B&M was selected

15   through this process because of competitive pricing and prior experience constructing

16   units using RICE technology. B&M is the industry leader in RICE projects over 25

17   MWs. By 2015, the company had installed a total of 72 RICE engines, with 60 of

18   these being Wärtsilä engines. B&M has constructed a total of 16 power generation

19   facilities utilizing RICE technology. One of these projects includes the 12 engine

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

Public Version
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Council Resolution R-07-432 Have Been Redacted

1   Wärtsilä plant at the Denton Energy Center in Denton, Texas, which employs the

2   same engines that will be installed at NOPS. It can achieve full load operation in 5

3   minutes and has black-start capabilities, which are both similar attributes to the

4   proposed Alternative Peaker. The Southwest Texas Electric Cooperative's Pearsall

5   plant is another plant constructed by B&M that is similar to the Alternative Peaker.

6   The Company worked with B&M to derive a cost estimate for the Alternative

7   Peaker that includes a reasonable amount of engineering design. As briefly

8   mentioned above, Non-EPC Costs were estimated by ESI and include project

9   management and oversight (both internal and external services), inspections and

10   testing, environmental permitting, pursuing regulatory approvals, temporary facilities

11   and supplies, and AFUDC.

12

13   Q25. DOES THE COST ESTIMATE REFLECT COST ESCALATION ADJUSTMENTS

14   AND PROJECT CONTINGENCIES?

15   A.   As is the case with the EPC Agreement underlying the originally proposed CT, the

16   EPC agreement for the Alternative Peaker provides a fixed price and fixed schedule

17   duration, provided that NTP is issued on or before a certain date. The NTP is not

18   expected to be issued prior to receipt of acceptable approval from the Council. If

19   NTP is not issued by that date, the EPC contract price is subject to escalation. If NTP

20   is delayed beyond ▮▮▮▮▮▮ the escalation is expected to be ▮▮ per month

21   with a yearly cap at ▮▮ for equipment (excluding RICE), materials and indirect costs.

22   Labor and RICE equipment are also subject to escalation. At this time, labor

1   escalation is a true-up based on actual sub-contractor costs that will be handled

2   utilizing an open book process. The RICE equipment is based on an exchange rate

3   factor and European producer price index at the time the equipment order is placed.

4   If NTP is not issued by ████████████ the EPC contract price is open to

5   renegotiation. Further, the Company included a contingency estimate that addresses

6   the fact that construction projects of the cost magnitude and time duration have cost

7   elements that are beyond the reasonable control of the Company and its management.

8   Even with a fixed-price EPC agreement and well-defined scope, experience

9   demonstrates that unpredictable events, such as discovery of unknown site conditions

10   or changes in laws or regulations, can require change orders that will affect project

11   costs. Thus, contingency must be included in the estimate in order to provide a

12   realistic estimate of the ultimate cost to complete the Project. The current Project

13   estimate contains a contingency line item of approximately six percent of the total

14   project costs, which is reasonable for a project of this nature. I describe risks to the

15   Project and mitigation plans later in my testimony

16

17   Q26. WHAT ARE SOME OF THE KEY MILESTONES IN THE ESTIMATED

18   PROJECT SCHEDULE?

19   A.   Substantial Completion is expected in October 2019, but no later than the end of 2019

20   provided regulatory approval is received by the end of October 2017 and NTP is

21   granted to the EPC contractor by November 1, 2017. B&M would receive incentives

22   for early completion and be required to pay liquidated damages for delayed

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

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1   completion. Some of the key milestones in the schedule (assuming certification by

2   November 1, 2017) are:

Milestone	Date
Regulatory approval – w/ New Orleans City Council	Nov 2017
Notice to Proceed	Nov 2017
Engine Purchase Order (critical milestone to achieve on time Commercial Operations date)	Nov 2017
Air Permit issued	Jan 2018
Coastal Use Permit issued	Jan 2018
Engine delivery	Dec 2018

3

1   Q27.   WHAT IS THE EXPECTED TIMING OF THE SPENDING AND FINANCIAL

2   COMMITMENTS ASSOCIATED WITH THE ALTERNATIVE PEAKER?

3   A.   The following HSPM graph depicts the Project's projected cash flow and cancellation

4   commitments:

5

6
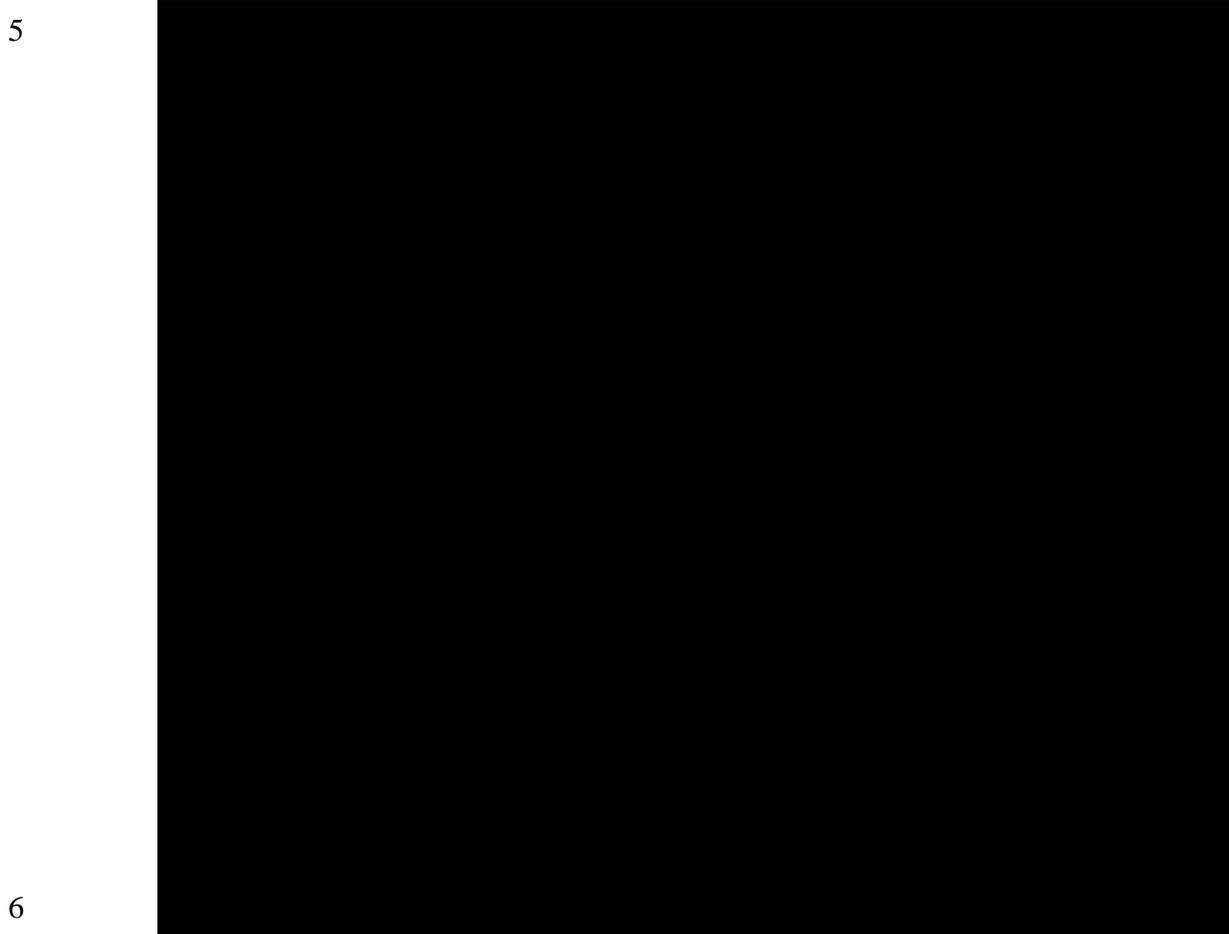
7

8   Q28.   WHAT DOES THE COMPANY CONSIDER TIMELY REGULATORY

9   APPROVAL?

10   A.   The current schedule is based on the expectation that the Company will have received

11   acceptable approval from the Council by November 1, 2017. Substantial completion

12   is expected to occur approximately 24 months following NTP.

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

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1

2   Q29.   ARE THERE BENEFITS TO ISSUANCE OF NTP PRIOR TO NOVEMBER 2017

3   IF EARLIER APPROVAL IS OBTAINED?

4   A.   Yes. An earlier NTP would potentially allow the unit to be brought on-line prior to

5   October 2019 and potentially allow customers to begin receiving the benefits from

6   this Alternative Peaker earlier. This would also shorten the period over which the

7   costs associated with AFUDC, Entergy internal costs and indirect costs would

8   accumulate.

9

10 **V.   PROJECT MANAGEMENT AND CONTRACTING APPROACH**

11 Q30.   HAS THE COMPANY'S PLAN TO MANAGE THE EPC CONTRACT CHANGED

12   SINCE ITS INITIAL FILING?

13 A.   No, the Company will follow the same structure outlined in my original Direct

14   Testimony.

15

16 Q31.   HOW DOES THIS FORM OF EPC CONTRACT COMPARE TO THE EPC

17   CONTRACT UTILIZED BY ELL FOR THE CONSTRUCTION OF NINEMILE 6,

18   ST. CHARLES POWER STATION, AND THE ORIGINAL CT PROPOSED IN

19   THIS CASE?

20 A.   The EPC contract for the Alternative Peaker is expected to contain very similar

21   Terms and Conditions as the EPC contract for Ninemile 6, SCPS, and the NOPS CT.

22   These contracts are fixed-price, date-certain form of contracts. Schedule duration is

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

Public Version
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Council Resolution R-07-432 Have Been Redacted

1   driven by the issuance of NTP and with escalation provisions if the NTP is delayed

2   and subject to renegotiation if NTP not issued by a certain date.

3   The Alternative Peaker contract has schedule incentives and liquidated

4   damages capped at ▮% of the EPC contract value; and an overall aggregate

5   monetary liability capped at ▮% of the total EPC contract value. The Alternative

6   Peaker contract is expected to include a craft labor escalation provision that will be

7   fixed, which is a difference from the referenced contracts. A summary of how the

8   EPC terms for the Alternative Peaker compare to other EPC contracts is provided in

9   Table 2:

10   **Table 2**

11

12

13

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Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

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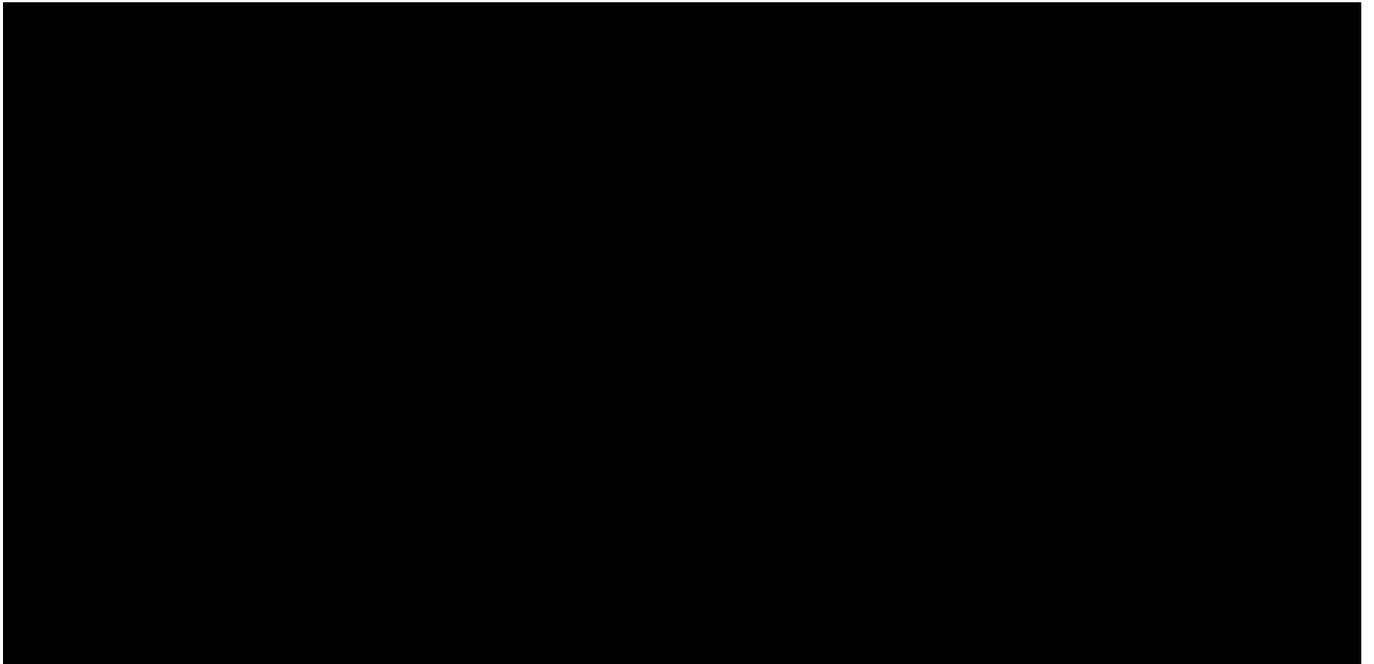
1 Q32. HAS THE COMPANY AND B&M AGREED UPON THE TERMS OF AN EPC

2   AGREEMENT?

3 A.   No. The parties are in the final stages of negotiating the EPC agreement. A summary

4   of the expected terms, however, has been attached as HSPM Exhibit JEL-10.

5

6   **VI.   CONSTRUCTION RISK MANAGEMENT AND MITIGATION**

7 Q33. HOW DO THE KEY RISKS AFFECT THE PROJECT'S SCHEDULE AND

8   PROJECTED COSTS?

9 A.   The fixed-price structure and well-defined scope of work are expected to minimize

10   the effect these key risks may have on project costs. The Company developed

11   mitigation plans and included a contingency in the project cost estimate that is

12   thought to be reasonably sufficient to mitigate identified risks. Delays in receiving

13   regulatory approvals or the required permits beyond the dates assumed in the project

14   schedule will increase total costs and result in a delayed in-service date. The project

15   schedule has been developed by optimizing the sequence of activities to produce the

16   shortest practical schedule at the lowest reasonable cost. The schedule has a built-in

17   contingency for critical path activities that will help mitigate short delays.

18

19 Q34. IS THE CONTINGENCY REFLECTED IN THE PROJECT COST ESTIMATE

20   ADEQUATE TO COVER ALL RISKS THAT COULD INCREASE COST?

21 A.   No, and that is not the purpose of contingency funds in project management.

22   Contingency is used to reasonably mitigate unplanned increases in project cost,

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Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

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1   whether caused by known risks or unforeseen risks. It recognizes that large

2   construction projects that span several years can be adversely affected by events

3   beyond the utility's control. ESI used a Monte Carlo simulation to determine the

4   level of contingency that would provide a reasonable level of mitigation of known

5   and unknown risks, but it is possible that some of these risks, if realized, could cause

6   cost increases beyond the contingency included in the cost estimate. It should be

7   noted that the Company does not retain any unused project contingency.

8

9   Q35. CAN YOU DISCUSS SOME OF THE KEY RISKS UNDER THE EPC

10   CONTRACT?

11   A.   Yes. While the EPC contract with B&M provides for a fixed price and fixed

12   schedule, any fixed-price contract presents a risk of price increases through change

13   orders and extra work claims. This risk has been mitigated to the extent possible by

14   broadly defining the scope of work assigned to B&M as including everything

15   necessary to complete the Project that meets the specification and performance

16   requirements, except for items expressly stated in the scope document to be the

17   Company's responsibility. The EPC contract also contains favorable change order

18   provisions that will enable the Company to direct B&M to proceed with a change

19   order as to which there is a good faith dispute between the parties, with the dispute

20   over price impact to be resolved in arrears.

21   This will protect the Company and its customers from the possibility that the

22   EPC contractor would threaten to delay work until change order disputes are resolved

1   to its satisfaction. Further, B&M must notify the Company before making any

2   changes required by force majeure events or changes in laws, and must document

3   such changes and the resulting impacts before being entitled to any schedule relief,

4   increase in the fixed price, or additional reimbursement. A discussion of other

5   construction risks, mitigation, and allocation for the Alternative Peaker is contained

6   on HSPM Exhibit JEL-11.

7   Finally, potential wage rate escalation on craft labor and *per diem* is expected

8   to be a significant risk as a result of the anticipated labor shortage in the Gulf Coast

9   region due to ongoing and proposed industrial capital investments over the next

10   decade. Should the project proceed as planned with NTP being given on November

11   1, 2017, B&M carries the risk as it relates to craft labor wage and *per diem*. If the

12   project is delayed for a year, the contract has an escalation provision as outlined

13   above.

14

15   Q36. PLEASE ELABORATE ON THE CRAFT LABOR PROVISIONS CONTAINED IN

16   THE EPC AGREEMENT.

17   A.   Under the terms of the agreement, B&M has agreed to assume productivity risk

18   associated with craft labor (*i.e.,* man-hour estimates). B&M has also agreed to

19   assume subcontractors' craft labor wage escalation risk, as well as that of engineering

20   and project management labor.

21   The EPC agreement pricing includes a total of ███████ total escalation in

22   the EPC's fixed price cost. The total escalation includes ██ per annum for

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

Public Version
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Council Resolution R-07-432 Have Been Redacted

1   equipment, ▮ per annum for commodity materials, ▮ per annum labor including

2   *per diem* and ▮% per annum for indirect costs.

3

4   Q37.   DOES THE EPC AGREEMENT HAVE PROVISIONS THAT MITIGATE RISK

5   RELATING TO B&M's PERFORMANCE?

6   A.   Yes. As I discussed earlier, the fixed-price, fixed-duration form of contract, coupled

7   with liquidated damages for late delivery, heat rate, and output provide a measure of

8   protection for customers.   Additionally, the EPC agreement requires that B&M

9   deliver a finished product that meets minimum requirements for performance and to

10   warranty that work for 12 months following substantial completion. The contractor is

11   also required to indemnify owner against claims for bodily injury and third-party

12   property damage.

13   The EPC agreement establishes a milestone payment structure whereby the

14   contractor will only be paid for the work that has been completed, as verified by the

15   Company. The milestone payments are subject to a cumulative cap with monthly

16   values stated in the contract that protects the Company's cash flow. Additionally,

17   payment retention will be accomplished in two ways: ▮▮▮▮▮▮▮▮▮▮

18   ▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮

19   ▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮

20   ▮▮▮▮▮▮▮

21

1   Q38.   WHAT TYPE OF INSURANCE IS INCLUDED IN THE COMPANY'S COST

2   ESTIMATE FOR THE NOPS PROJECT?

3   A.   As with units constructed by other EOCs, such as the Ninemile 6 CCGT, the

4   Company intends to procure insurance prior to the issuance of NTP. The expected

5   coverage will include Builders All Risk and Delay in Startup. Please see my Direct

6   Testimony for more information regarding these insurances.

7

8   Q39.   WHAT   IS   THE   COMPANY'S   POLICY   REGARDING   DIVERSE

9   SUBCONTRACTOR PARTICIPATION IN THE CONSTRUCTION OF NOPS?

10   A.   As a part of the EPC Agreement, ENO will require B&M to provide opportunities to

11   small and disadvantaged businesses for participation in any subcontracts and purchase

12   orders let in the performance of its obligations as the EPC contractor.   The Company

13   requires B&M to develop and maintain a list of Diverse Subcontractors and Suppliers

14   that will be supplied to ENO on a quarterly basis.   Minority-owned businesses,

15   women-owned businesses, veteran-owned businesses, and disabled-veteran-owned

16   businesses, among others, are included within the meaning of "diverse subcontractors

17   and suppliers."   B&M will be required to submit a plan for utilizing diverse

18   subcontractors and suppliers to ensure such participation in the construction of NOPS.

19

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

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1 Q40. FINALLY, YOUR (NOVEMBER 2016) SUPPLEMENTAL DIRECT TESTIMONY

2   REFERENCED A TECHNICAL REPORT PREPARED BY C-K ASSOCIATES

3   ("CK"), LLC AND LOSONSKY AND ASSOCIATES, INC. HAS THAT REPORT

4   BEEN UPDATED TO EVALUATE THE ALTERNATIVE PEAKER?

5 A.   Yes. In his Supplemental Direct Testimony, one of the authors of the C-K Technical

6   Report, Dr. George Losonsky, discusses the analyses he performed for the Addendum

7   to the C-K Technical Report that is attached to his Testimony as Exhibit GL-2. As

8   Dr. Losonsky's Testimony addresses in detail, he performed additional evaluations of

9   possible impacts from groundwater withdrawal associated with the operation of the

10   Alternative Peaker. Specifically, he performed calculations to determine the range of

11   possible drawdown levels, and any resulting consolidation settlement, that might

12   occur due to the operation of the Alternative Peaker. He also supplemented his

13   evaluation of groundwater usage issues related to the CT Unit by performing the

14   same calculations to determine the possible impacts of the expected groundwater

15   usage required for the CT. Dr. Losonsky concluded, based on the calculations set

16   forth in Exhibit GL-2, that neither the Alternative Peaker nor the CT would

17   "exacerbate subsidence or cause damage to infrastructure in New Orleans East."

18   Moreover, CK conducted an air screening model evaluation using

19   AERSCREEN software to understand how the proposed Alternative Peaker project

20   might affect air quality in New Orleans East. (An air screening model evaluation was

21   previously performed for the CT project and a report of that evaluation was attached

22   to my Supplemental Direct Testimony filed in December 2016.) Based on the

Entergy New Orleans, Inc.
Supplemental and Amending Direct Testimony of Jonathan E. Long
CNO Docket No. UD-16-02

Public Version
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Council Resolution R-07-432 Have Been Redacted

1   AERSCREEN model evaluation, the CK report concludes that in no case will the

2   emissions cause ambient air concentration to exceed regulatory standards, which are

3   protective of human health and the environment. The CK report also concludes that

4   the proposed Alternative Peaker will represent a significant reduction in allowable

5   emissions compared to the emissions of the former Michoud plant and that emissions

6   from the RICE project are dissipated before they reach the fence line to

7   concentrations much below the National Ambient Air Quality Standards. The updated

8   C-K Technical Report regarding emissions for the Alternative Peaker is attached

9   hereto as Exhibit JEL-12.

10

11   Q41.   DOES THIS CONCLUDE YOUR TESTIMONY?

12   A.   Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **JONATHAN E. LONG,** who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

_____
Jonathan E. Long

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 20th DAY OF JUNE, 2017

_____
NOTARY PUBLIC
My commission expires: Upon death

Harry M. Barton
Notary Public
Notary ID# 90845
Parish of Orleans, State of Louisiana
My Commission is for Life

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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

EXHIBIT JEL-10

and

EXHIBIT JEL-11

PUBLIC VERSION

**HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED**

JULY 2017

TECHNICAL REPORT
RECIPROCATING INTERNAL
COMBUSTION ENGINES ("RICE")
AIR QUALITY EVALUATION

New Orleans Power Station
Entergy New Orleans, Inc.
3601 Paris Road
New Orleans, Louisiana 70129

July 6, 2017

Prepared by:

CK ASSOCIATES
Environmental Consultants

17170 Perkins Road
Baton Rouge, LA 70810
225-755-1000
CK Project Number: 14005

EXECUTIVE SUMMARY

Entergy New Orleans, Inc. (ENO) has proposed to construct either a combustion gas turbine (CT) electric generation facility or a 128 MW natural-gas-fired reciprocating internal combustion engines ("RICE") facility. The RICE option is composed of seven 18 MW natural gas-fired reciprocating internal combustion engines with associated ancillary equipment. The new facility is referred to as New Orleans Power Station (NOPS), and will be located at the site of the deactivated Michoud Electric Generating Plant (Michoud plant). Some members of the community have raised concerns regarding air quality impacts of the proposed NOPS alternatives. However, both proposed NOPS alternatives will be permitted for less allowable emissions than the previously active Michoud plant at the same site.

CK Associates, LLC (CK Associates) conducted an air screening model evaluation using AERSCREEN to address community concerns and to understand how the proposed RICE alternative might impact air quality in New Orleans East. The CT alternative has previously been the subject of an air screening model evaluation (CK Associates, 2016. Technical Report - Evaluation of Groundwater Withdrawal and Air Quality).

Based on the air screening model evaluation, it was concluded that the emissions from the proposed RICE alternative will in no case result in ambient air concentrations above air quality regulatory standards, which are protective of human health and the environment.

This report was prepared by scientists familiar with local, regional, and statewide environmental conditions, air dispersion modeling, and air quality regulations, who are qualified to discuss the subject matter.

TABLE OF CONTENTS

LIST OF TABLES

1.0   INTRODUCTION

Entergy New Orleans, Inc. (ENO) has proposed to construct either a combustion gas turbine (CT) electric generation facility or a 128 MW natural-gas-fired reciprocating internal combustion engines ("RICE") facility. The RICE option is composed of seven 18 MW natural gas-fired reciprocating internal combustion engines with associated ancillary equipment. The new facility is referred to as New Orleans Power Station (NOPS), and will be located at the site of the deactivated Michoud Electric Generating Plant (Michoud plant). Some members of the community have raised concerns regarding air quality impacts of the proposed NOPS alternatives. However, both proposed NOPS alternatives will be permitted for less allowable emissions than the previously active Michoud plant at the same site.

C-K Associates, LLC (CK Associates) conducted an air screening model evaluation using AERSCREEN to address community concerns and to understand how the proposed RICE alternative might impact air quality in New Orleans East. The CT NOPS alternative has previously been the subject of an air screening model evaluation (CK Associates, November, 2016). This report presents the analysis and calculations that support the following conclusion:

> **The emissions from the proposed RICE alternative will result from combustion of clean burning natural gas. In no case, will emissions result in ambient air concentrations above air quality regulatory standards, which are protective of human health and the environment.**

The report was prepared by environmental scientists at CK Associates, an environmental and engineering consulting firm licensed in the state of Louisiana. The scientists who prepared this report are familiar with environmental regulations and relevant air quality subjects and are qualified to prepare this report.

2.0   AIR EMISSIONS EVALUATION

Under the Clean Air Act, the Environmental Protection Agency (EPA) is required to regulate emission of pollutants to protect public health and welfare. State and local governments also monitor and enforce Clean Air Act regulations, with oversight by the EPA. The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. The EPA has set NAAQS (limits) for six principal pollutants, which are called "criteria" air pollutants. They are particle pollution (often referred to as particulate matter, PM_{10} and $PM_{2.5}$), photochemical oxidants and ground-level ozone, carbon monoxide, sulfur dioxide, nitrogen dioxide, and lead.

The RICE facility will include seven (7) natural gas-powered engines and supporting equipment (e.g. an emergency generator and a firewater pump). The RICE facility will require a permit issued by the Louisiana Department of Environmental Quality (LDEQ). The air permit will set emission limit controls and requirements for testing.

1

2.1 Proposed Air Emissions

The RICE facility will use newer, more efficient technology that must comply with emission limitations that are stricter than those that existed during the time when the deactivated units were installed at the former Michoud Plant. The allowable air emissions for the RICE facility will be lower for all criteria air pollutants than the permitted emissions for the former Michoud Plant. **Table 1** compares the allowable air emissions of the previous plant versus the RICE facility for all criteria pollutants. This table shows that the reduction in air emissions range from 49% for Volatile Organic Compounds (VOC) to 99% for Nitrogen Oxides (NOx).

2.2 Screening Level Air Modeling

Air dispersion modeling is the mathematical simulation of how air pollutants disperse in the ambient atmosphere. The LDEQ has emission thresholds that, if exceeded, require permit applicants to perform air dispersion modeling during the permitting process. Because the net emissions from the RICE NOPS alternative are below the air emissions thresholds, the regulations do not require that air dispersion modeling be performed. Nevertheless, at ENO's request CK conducted voluntary screening level air dispersion modeling using conservative assumptions to understand ground-level concentration exposure to the public. The air dispersion model can effectively estimate the downwind ambient concentrations of constituents emitted from the RICE facility equipment sources.

Air dispersion modeling is performed with computer programs that solve the mathematical equations and algorithms which simulate the dispersion of emissions to air. EPA preferred models include AERSCREEN for screening analysis and AERMOD for refined model simulations. AERSCREEN is the recommended screening model that will produce conservative impact estimates without the need for actual hourly meteorological or detailed terrain data. If air quality evaluated using AERSCREEN passes the appropriate standards (e.g. NAAQS) there is no need for additional modeling (e.g. Refined AERMOD). AERSCREEN model will produce estimates of "worst-case" 1-hour concentrations for a single source, based on a matrix of meteorological conditions, and includes conversion factors to estimate "worst-case" 3-hour, 8-hour, 24-hour, and annual concentrations. AERSCREEN is intended to produce concentration estimates that are equal to or greater than the estimates produced by AERMOD with a fully developed set of actual meteorological and terrain data, but the degree of conservatism will vary depending on the application.

The AERSCREEN model was developed to provide an easy-to-use method of obtaining pollutant concentration estimates. To perform a modeling study using AERSCREEN, data for the following input requirements must be supplied:

2

- Source Type (Point, Flare, Area or Volume);
- Physical Source and Emissions Characteristics (emission rate, stack height, stack diameter, stack gas exit velocity and temperature, and receptor height above ground);
- Meteorology (surface characteristics, ambient temperatures, minimum wind speed, and anemometer height);
- Building downwash; and,
- Terrain (flat, elevated and complex terrain).

The stack parameters and emission rates employed in the RICE facility modeling analysis are included in **Table 2.** Also, the parameters used for the development of the meteorological data set are included in **Table 2**.

Table 3 shows the AERSCREEN modeling outputs of the RICE facility maximum ground-level concentrations compared to the NAAQS. Several averaging periods are considered based on the form of the NAAQS standard. The modeling included conservative assumptions, and demonstrates that personal ground-level exposure due to the NOPS emissions will be well below the applicable NAAQS.

3.0   CONCLUSIONS AND SUMMARY

The following conclusions were made based on the analysis presented herein:

- No new chemicals will be released due to NOPS when compared to the historical operations of the Michoud plant;
- Chemicals emitted are consistent with natural gas combustion;
- The proposed RICE facility will represent a significant reduction in allowable emissions compared to the allowable emissions of the former Michoud plant; and,
- Emissions are dissipated before they reach the fence line to concentrations much below the limits for public breathing level air (NAAQS).

In summary, **the emissions from the proposed RICE NOPS alternative will result from combustion of clean burning natural gas. The proposed RICE allowable emissions are less than the permitted emissions from the former Michoud plant. In no case, will the emissions cause ambient air concentrations to exceed regulatory standards, which are protective of human health and the environment.**

3

TABLE 1

Table 1
RICE Air Emissions Summary
New Orleans Power Station

Constituent	Constituent Identifier	Emissions Allowed Under Current Permit (Ton/Year)	Proposed RICE Permit Limits[1] (Ton/Year)	Difference Between Existing Permit and Proposed RICE Limits (Tons/Year)	Percent Reduction
Particulate Matter Less than 10 microns	PM_{10}	283.55	97.61	-185.94	**66%**
Particulate Matter Less than 2.5 microns	$PM_{2.5}$	283.55	97.61	-185.94	**66%**
Sulfur Dioxide	SO_2	22.55	2.87	-19.68	**87%**
Nitrogen Oxides	NO_X	8596.89	50.39	-8546.50	**99%**
Carbon Monoxide	CO	3132.22	89.31	-3042.91	**97%**
Volatile Organic Compounds	VOC	205.35	105.38	-99.97	**49%**

[1] Proposed permit limits based on information received from CB&I

TABLE 2

Table 2
RICE Screening Model Inputs Summary
New Orleans Power Station

Source ID	Stack Height (ft)	Exit Temperature (°F)	Exit Velocity (fps)	Stack Diameter (ft)	NOx (lb/hr max)	NOx (lb/hr avg)	CO (lb/hr max)	PM$_{10/2.5}$ (lb/hr max)	PM$_{10/2.5}$ (lb/hr avg)	SO$_2$ (lb/hr max)	SO$_2$ (lb/hr avg)	Benzene (lb/hr avg)	Formaldehyde (lb/hr avg)
Per Engine	60	697	87.5	5.32	2.49	1.61	4.97	4.23	3.18	0.13	0.094	0.037	1.23
Firewater Pump	9	1056	51	0.67	NA	0.02	1.65	0.10	0.002	0.003	0.002	0.002	0.002
Emergency Generator	13	1015	293.7	0.83	NA	0.203	11.53	0.67	0.007	0.02	0.002	0.011	0.001

[1]24-Hour averaging period for PM$_{2.5}$ modeled using the total emitted from the emergency units for testing in a 24-hour period.

Minimum Wind Speed (m/s)	Anemometer Height (m)	Surface Albedo	Bowen Ratio	Surface Roughness Length (m)
0.5	10	0.15	0.21	0.088

TABLE 3

Table 3
RICE Screening Model Results
New Orleans Power Station

Constituent	Constituent Identifier	Averaging Period	RICE (7 Engines) Model Predicted Concentration (ug/m³)	NAAQS (ug/m³)
Particulate Matter Less than 10 microns	PM$_{10}$	24-Hour	21.82	150
Particulate Matter Less than 2.5 microns	PM$_{2.5}$	24-Hour	21.82	35
		Annual	2.7	12
Sulfur Dioxide	SO$_2$	1-Hour	1.18	196
		3-Hour	1.36	1,300
		24-Hour	0.82	365
		Annual	0.12	80
Nitrogen Dioxide	NO$_2$	1 Hour	18.56	188
		Annual	1.18	100
Carbon Monoxide	CO	1-Hour	180	40,000
		8-Hour	162	10,000
Benzene		Annual	0.046	12
Formaldehyde		Annual	1.04	7.69

NOTES:

NAAQS = National Ambient Air Quality Standard

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

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

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

CHARLES W. LONG

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JULY 2017

TABLE OF CONTENTS

EXHIBITS

Exhibit CWL-6   Summary of Updated Reliability Analyses

1   **I.   INTRODUCTION AND PURPOSE**

2   Q1.   PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

3   A.   My name is Charles W. Long. I am employed by Entergy Services, Inc. ("ESI"),[1] a

4   service company to the EOCs, as Director, Transmission Planning.   My business

5   address is 6540 Watkins Drive, Jackson, Mississippi, 39213.

6

7   Q2.   ARE YOU THE SAME CHARLES W. LONG WHO FILED DIRECT

8   TESTIMONY IN THE ABOVE CAPTIONED DOCKET?

9   A.   Yes.

10

11   Q3.   ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

12   A.   I am testifying on behalf of Entergy New Orleans, Inc. ("ENO" or the "Company").

13

14   Q4.   WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?

15   A.   My Supplemental and Amending Direct Testimony ("Supplemental Direct

16   Testimony") supports the Application in this proceeding, which seeks, among other

17   things, approval to proceed with a project to construct New Orleans Power Station

18   ("NOPS"), which will consist of either a combustion turbine ("CT") resource with a

19   summer capacity of 226 megawatts ("MW"), or alternatively, seven Wärtsilä

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[1]   ESI is an affiliate of the Entergy Operating Companies ("EOCs") and provides engineering, planning,
accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy
Arkansas, Inc. ("EAI:"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), Entergy New
Orleans, Inc., and Entergy Texas, Inc. ("ETI").

1

1   18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator sets

2   ("Alternative Peaker").

3

4   Q5.   PLEASE PROVIDE AN OVERVIEW OF YOUR SUPPLEMENTAL DIRECT

5   TESTIMONY.

6   A.   My Supplemental Direct Testimony first reemphasizes the unique operational

7   reliability-related characteristics of the Downstream of Gypsy ("DSG") region of the

8   power system that serves the electric load in the City of New Orleans. It next

9   describes ENO's transmission reliability analysis, which concludes that the original

10   unit proposed, the CT, would eliminate all reliability concerns throughout the

11   planning horizon and help create an increased reliability margin, which is a level of

12   reliability that exceeds the minimum level required to maintain a reliable grid but

13   allows room for growth and provides some operational margin.

14   The analysis also shows that the Alternative Peaker would mitigate the most

15   serious reliability concerns, namely the potential cascading outages in ENO's service

16   territory, but would not eliminate all projected reliability risks associated with all

17   categories of contingencies required for North American Electric Reliability

18   Corporation ("NERC") compliance. Thus, some transmission investment could still

19   be needed at some point to comply with NERC standards if the Alternative Peaker is

20   constructed; but as discussed more fully below, the Company would recommend a

21   wait-and-see approach with respect to those upgrades given the timing and level of

22   overloading involved. My testimony also discusses the transmission-related benefits

23   that local generation is expected to produce, and it provides an update regarding

1   Midcontinent Independent System Operator, Inc.'s ("MISO") Definitive Planning

2   Phase ("DPP") generator interconnection process.

3

4   **II.   OVERVIEW OF RELIABILITY RISKS IN NEW ORLEANS**

5   Q6.   PLEASE DEFINE THE TERM "LOCAL RELIABILITY CRITERIA."

6   A.   The term "local reliability criteria," as it is used in the context of transmission

7   planning and operations, is a very broad concept that commonly refers to more

8   stringent criteria or operating practices defined for a "local area," or a portion of the

9   transmission system which usually has transmission topological considerations that

10   differ from the remainder of the electric grid such that such local reliability criteria

11   are warranted for the local area given those geographical constraints.

12

13   Q7.   PLEASE ALSO DEFINE THE TERM "LOAD POCKET."

14   A.   A load pocket generally refers to a region of high load concentration, which is

15   dependent upon local generation capability within its borders to reliably serve load

16   due to a limit on the ability to import power into the region. Often, as is the case with

17   DSG, simply expanding the transmission system to import more power is not the

18   most cost-effective method to increase a utility's local reliability in the load pocket

19   due to geographical and constructability constraints that hinder the expansion of the

20   transmission system in a cost-efficient manner. Moreover, an expansion of the

21   transmission system to facilitate greater amounts of power imports into a local pocket

22   provides limited reliability improvements, as I shall discuss below.

1   Furthermore, in the case of the Amite South and DSG load pockets, several of

2   the local generators located within the load pockets are supercritical steam-turbine

3   generators with very long start-up times. The long start-up times further constrain the

4   operating flexibility of the system, especially for operating conditions that require the

5   commitment of a generator for the mitigation of transmission constraints. Hence,

6   load pockets are often operated to more stringent reliability criteria due to these

7   unique operating characteristics. The load pockets at issue in this proceeding, Amite

8   South and DSG, have been described in detail in my original Direct Testimony on

9   pages 3-5.

10

11   Q8.   HOW DO THESE RELIABILITY CONCEPTS OPERATIONALLY AFFECT NEW

12   ORLEANS FROM A TRANSMISSION PERSPECTIVE?

13   A.   New Orleans is located in the eastern half of the DSG load pocket and is very

14   sensitive to local reliability issues. The City is located in a geographical and

15   electrical peninsula bordered by water on the north, east and south. Almost all

16   electrical energy is imported into the City from the west, primarily through East

17   Jefferson Parish via the transmission grid, while a small amount of electric energy is

18   transported through the very limited transmission capability from the Slidell area over

19   the open waters of Lake Pontchartrain. Thus, the flow of energy into the City is

20   heavily biased towards a west to east flow pattern.

21   The existing transmission facilities serving the City traverse a limited set of

22   viable transmission corridors across wetlands and generally poor soil conditions

23   through an area heavily congested with industrial, commercial, and residential

1   structures. In other words, without a local source of energy, such as the proposed

2   NOPS, the City in general, and New Orleans East in particular, is entirely dependent

3   on the set of existing transmission lines situated in a relatively small geographical

4   area. Because of this lack of geographic diversity, it can reasonably be expected that

5   all lines, save perhaps the single line from Slidell, would be vulnerable to similar

6   outages and operational challenges.

7   In fact, without a local resource, the loss of even a portion of these

8   transmission facilities delivering energy from the west into the City would likely

9   prevent the Company from serving its entire load. Moreover, it should be noted that

10   the loss of even one line for an extended period of time could result in significant

11   separations[2] of market energy prices in MISO, which is not uncommon since the

12   retirement of the Michoud resources. These price separations are often precursors to

13   reliability issues,[3] but all of these concerns can be significantly reduced with the

14   addition of a local resource. By way of analogy, in order to ensure a reliable supply of

15   water, ancient cities preferred to have a local source of fresh water as opposed to

16   relying on aqueducts or other methods to transport water into the city because it was

---

[2]   These price separations are the result of congestion on the transmission system. Congestion occurs when the flow of large amounts of power on the electric system result in transmission constraints, which in turn create higher Locational Marginal Prices ("LMPs") on the downstream side of the constraint and lower LMPs on the upstream-side of the constraints. This price separation in the energy market is designed to incentivize generators on the downstream side of the constraint to dispatch up (in order to take advantage of the higher LMP) and generators in the upstream side to dispatch down (with the lower LMP inducing these resources to generate less) in a self-correcting action to mitigate the constraint.

[3]   These reliability constraints can be observed operationally when there are not sufficient resources to re-dispatch to mitigate the constraints in the system, no matter how large the price separation in the energy market. Typically, there is a corresponding NERC TPL reliability violation that can be observed in the long-term transmission planning process as well.

1   within their control and thus reduced their vulnerability to events beyond their

2   control.

3   Moreover, within a load pocket, over-reliance on transmission to meet

4   demand also diminishes operational flexibility. For example, if the Company needs

5   to take a planned outage of a transmission element, scheduling such an outage would

6   be extremely difficult in an environment where nearly all transmission elements are

7   loaded near capacity. This creates an inflexible operational environment where there

8   are no operational margins to perform necessary maintenance on the transmission

9   grid or the generating resources interconnected to the transmission network. A

10 generator sited locally will have the effect of creating operational flexibility by easing

11 the loading on transmission elements and making it easier to keep the grid reliable

12 during both planned and unplanned outages of transmission elements and generating

13 resources.

14

15 Q9.   PLEASE   PROVIDE   SOME   SPECIFIC   OPERATIONAL   EXAMPLES   OF

16   RELIABILITY ISSUES THAT WOULD HAVE BEEN MITIGATED BY THE

17   PRESENCE OF A GAS-FIRED GENERATOR AT THE MICHOUD FACILITY.

18 A.   As mentioned above, one example of the consequences of ENO not having a local

19   generator is that the DSG load pocket is more dependent on the transmission network

20   to serve the Company's electric load. The large flows of power on the transmission

21   system often lead to stressed operational conditions, resulting in the rejection of

22   outage requests needed for maintenance and construction. In the first half of this year

23   alone, outages involving a 115 kV transmission segment, a 230/115 kV auto-

1   transformer, five 230 kV transmission lines and two 500 kV transmission lines were

2   denied because of reliability constraints that could not be mitigated without risking

3   electric service to the Company's customers. Simply put, having a local generator

4   will reduce the stress on heavily loaded transmission lines when necessary, which

5   could mitigate the cancellations of maintenance and construction outages, without

6   which critical equipment may be put at risk, potentially increasing cost to customers.

7   Another example of severe operational constraints that result from a scarcity

8   of generation capacity is the occurrence of load-at-risk alerts and maximum

9   generation events. Local generation shortfalls that occur operationally are monitored

10   using the Entergy Load Risk Alert Levels ("ELRAL") protocol of four alert levels.[4]

11   Since the retirements of the Michoud resources, the operational generation shortages

12   have resulted in six ELRAL Level 1 issuances for DSG, six ELRAL Level 1

13   issuances for Amite South (two of these ELRAL declarations being for both Amite

14   South and DSG), fourteen ELRAL Level 1 issuances for the MISO-wide system, and

15   one ELRAL Level 2 event for the MISO region. Each of the ELRAL level 1 notices

16   implies that a scarcity of generation has resulted in the possibility that there may be

17   loss of load in the DSG and/or Amite South load pocket. The ELRAL Level 2 did

---

[4]   ELRAL Level 0: Normal operation with no current risk to customer load.

ELRAL Level 1: Entergy foresees or is experiencing conditions where in the event of multiple contingencies, customer load in the affected area(s) may be at risk. All available resources are being utilized to meet customer load in the affected area(s).

ELRAL Level 2: Entergy foresees or is experiencing conditions where in the event of a single contingency, customer load in the affected area(s) may be at risk. Entergy foresees or has implemented interruption of Non-Firm Load in the affected area(s).

ELRAL Level 3: Entergy foresees or has implemented interruption of Firm Load in the affected area(s).

1   result in the curtailment of non-firm load in south Louisiana, including in New

2   Orleans.

3   Local generation in the New Orleans area would certainly reduce the stresses

4   to the transmission system that result in the types of operational issues mentioned

5   above. Moreover, it should also be noted that many of the existing generators in the

6   region are older, less efficient units that face the risk of deactivation, as described by

7   Company witness Seth E. Cureington in his Supplemental Direct Testimony. Over

8   time, as aging resources in Amite South, DSG, and elsewhere in the system

9   deactivate, such operational issues and load-at-risk alerts will likely increase in

10   frequency and severity. The certainty of power generated from a resource such as the

11   NOPS will help minimize operational constraints such as the ones listed above, will

12   help avoid long-term NERC TPL reliability standard violations, and would help

13   support future load growth in the New Orleans area.

14

15   **III.   RELIABILITY ANALYSIS RESULTS[5]**

16   Q10. HAS THE COMPANY UPDATED ITS LONG-TERM RELIABILITY ANALYSIS

17   TO ACCOUNT FOR THE UPDATED LOAD FORECAST?

18   A.   Yes. Using the most recent load forecast available, the Company has performed a

19   reliability assessment to determine the long-term reliability of the transmission

20   network under various scenarios. The results of this analysis are as follows:

21

---

[5]   Please see Exhibit CWL-6, attached hereto, for a summary of ENO's Reliability Analyses.

1 **"No NOPS" Scenario**

2   By 2019, if NOPS is not constructed, several 230 kV and 115 kV lines in

3   DSG would overload without additional transmission investment. In addition, a

4   Category P6[6] contingency event would result in severe overloads of several 115 kV

5   lines in the DSG area, leading to uncontrollable cascading outages of up to six 115

6   kV transmission branches. Consequently, a voltage collapse and load shed event in

7   the ENO transmission network would result from the severe reactive power deficit

8   due to the loss of the transmission branches and reactive power support in the ENO

9   transmission grid. Also in 2019, a breaker failure contingency at the Ninemile 230 kV

10   substation was observed to result in three 230 kV transmission line overloads and one

11   115 kV transmission line overload.

12   In the 2022 study year, a breaker failure at the Ninemile 230 kV substation

13   was observed to result in two 230 kV transmission line overloads. In addition, a

14   category P6 contingency in the ENO transmission grid results in the cascading

15   outages of five 115 kV transmission branches in the ENO transmission network

16   resulting in a voltage collapse and wide-spread load shedding in the New Orleans

17   area.

---

6   A P6 event is the loss of a transmission facility followed by system adjustments, followed by the loss of an additional transmission facility. P6 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.

1   In the 2024 study year, the breaker failure at the Ninemile 230 kV substation

2   results in two 230 kV transmission line overloads.[7] The category P6 contingency

3   results in the cascading outages of five 115 kV transmission branches in the ENO

4   transmission network resulting in a voltage collapse and wide-spread load shedding in

5   the New Orleans area.

6   In the 2027 study year, besides the two 230 kV overloads resulting from the

7   230 kV breaker failure at the Ninemile substation that were observed in the 2024

8   study year, an additional 230 kV transmission line is loaded to its rated capacity as a

9   result of the same contingency. Additionally, the category P6 contingency results in

10   the cascading outages of seven 115 kV branches in the ENO transmission system,

11   resulting in widespread load loss and a voltage collapse. In order to mitigate the

12   constraints observed in the system in the 2019, 2022, 2024, and 2027 study years in

13   the absence of any incremental generation, the following transmission upgrades

14   would have to be constructed:

---

[7]   Transmission upgrades in the Company's current long-term transmission plan, in particular, due to the
planned transmission upgrades associated with the Target Appendix A MTEP17 Jefferson Parish Area
Reliability Plan project allow for fewer overloads resulting from the failure of the 230 kV breaker at Ninemile
in the 2022 study year, compared to the 2019 study year.

1   **Table 1: "No NOPS" Transmission Upgrades**

Project	Voltage	Total Project Cost	Need-by Date
Avenue C to Pauger Line Upgrade	115kV	$21,050,000	Summer 2021
Chalmette to Patterson Line Upgrade	115kV	$12,979,000	Summer 2021
Michoud to Curran Line Upgrade	230kV	$100,000	Summer 2027
Almonaster to Curran Line Upgrade	230kV	$18,050,000	Summer 2021
Southport to Joliet Line Upgrade	230kV	$5,125,000	Summer 2021

2

3   **"110 MW generator" Scenario**

4   The results of the reliability analysis of the transmission system assuming a

5   110 MW generator at Michoud, which is a good proxy for the Alternative Peaker,

6   indicated that no transmission constraints would be expected in the system in the

7   2022 and 2024 study years. On the other hand, in the 2027 study year, a 230 kV

8   breaker failure at Ninemile would result in two 230 kV transmission lines

9   overloading. Notably, the 110 MW resource would be effective in mitigating the

10   transmission constraints resulting from the category P6 contingency mentioned

11   above, thus preventing the cascading outages and potential loss of load for ENO

12   customers. Moreover, because the overloading in 2027 is relatively marginal and

13   occurs approximately ten years in the future, the Company would propose to wait to

14   determine if any transmission upgrades are necessary once NOPS is constructed.

15   However, if it is decided that a transmission project should be constructed in order to

1   mitigate the constraints observed in the system in the 2027 study year, the following

2   transmission upgrades are currently estimated to be required:

3   **Table 2: "110 MW Scenario" Transmission Upgrades[8]**

Project	Voltage	Total Project Cost	Need-by Date
Almonaster to Curran Line Upgrade	230kV	$18,050,000	Summer 2027
Southport to Joliet Line Upgrade	230kV	$5,125,000	Summer 2027

4

5   **"226 MW" Scenario**

6   The results of the reliability assessment conducted with the assumption that

7   the 226 MW NOPS resource will be interconnected to the grid in June 2019 and at the

8   proposed capacity show that none of the constraints mentioned above in the 2019,

9   2022, 2024, or the 2027 study years were observed. Therefore, no upgrades would be

10   required if NOPS were to interconnect to the transmission grid at Michoud as

11   scheduled and at a capacity of 226 MW. The 226 MW NOPS resource is also

12   effective in mitigating the transmission constraints resulting from the category P6

13   contingency that was observed in the "No NOPS" scenario mentioned above, thus

14   preventing the cascading outages and potential loss of load for ENO customers.

15

---

[8]   Transmission upgrades, planning level cost estimates for these upgrades, and the required in-service dates for the mitigation of reliability constraints resulting from a 110 MW generator interconnected at Michoud.

1 Q11. PLEASE SUMMARIZE THE RESULTS AND TAKEAWAYS FROM ENO'S

2 RELIABILITY ANALYSES.

3 A. The analyses show that if the Company does not add any locally-sited generation in

4 the ENO area in the near future, the Company will be required to plan, fund, and

5 construct transmission upgrades to comply with NERC reliability standards in order

6 to maintain the reliability of the grid and to mitigate the potential risk of cascading

7 outages. Adding a unit with an output of 226 MW will eliminate all grid reliability

8 issues within the current 10-year planning horizon. It should also be noted that the

9 Company's analysis showed that a 170 MW generator would also eliminate all

10 reliability issues within the planning horizon.

11 On the other hand, constructing the 110 MW, which is an adequate proxy for

12 the Alternative Peaker, will eliminate the cascading outages, but not address all

13 constraints in all years, thus indicating that additional transmission investment <u>may</u> be

14 needed. However, because the overloads under the 110 MW Alternative Peaker

15 scenario do not occur until 2027 and are relatively minor, the Company will wait to

16 see whether it should move forward with the construction of the identified

17 transmission upgrades.

18

19 Q12. WAS THE LATEST UPDATED LOAD FORECAST USED IN ENO'S

20 RELIABILITY ANALYSIS?

21 A. Yes. The load forecast used to create ENO's reliability analysis described herein is

22 ENO's current load forecast.

23

1   Q13.   DID THE 2016 OR 2017 MISO TRANSMISSION EXPANSION PLAN ("MTEP")

2   REPORTS IDENTIFY THE PROJECTS LISTED ABOVE THAT WOULD BE

3   NECESSARY ABSENT NOPS?

4   A.   MISO's reliability transmission planning process calls for transmission solutions to

5   be identified for category P6 contingencies only if the consequent load-shed is greater

6   than 1,000 MW. In this case, MISO's 1,000 MW trigger point would not result in a

7   MISO identified project until approximately 90% of ENO's load was at risk. While

8   this level of risk may be acceptable to larger utilities in the MISO footprint, the

9   Company believes that this level of risk is unacceptably high for our customers in

10   New Orleans. Thus, while MISO's transmission planning criteria do not result in the

11   identification of these projects, the Company will enter these projects into a future

12   MTEP process and submit them to MISO for their consideration, should NOPS not be

13   constructed.

14   Moreover, it should also be noted that MISO identified the failure of the

15   circuit breaker at the Ninemile 230 kV switchyard (mentioned in the results of the

16   reliability assessment in the response to Q 10) as a critical contingency during the

17   generator retirement Attachment Y reliability assessment for Michoud Unit 3. The

18   Company worked with ELL and MISO to develop an operating procedure[9] that

19   ensured that this circuit breaker could be operated open whenever the breaker failure

20   event could be expected to produce reliability constraints on the system. Operating

---

[9]   The Company implemented the breaker failure logic in the real-time state estimator such that the logic
instructs system operators to open the circuit breaker if the simulated circuit breaker failure contingency results
in overloads in the system.

1   the circuit breaker in the open position ensures that the circuit breaker cannot fail

2   while responding to a short-circuit in the system, thus preventing additional circuit

3   breakers electrically adjacent to the failed circuit breaker from having to operate to

4   isolate the fault. This in turn prevents the disconnection of more transmission lines

5   and more system overloads. However, such procedures to operate circuit breakers in

6   the open position are always a temporary mode of operation until a long-term remedy

7   can be put into place (in this case, NOPS and the additional transmission upgrades

8   already included in the Company's long-term transmission plan).   The

9   implementation of this operating procedure allowed the Company to deactivate the

10   Michoud 3 resource while also safeguarding the security of the transmission grid until

11   a long-term mitigating measure (ideally, the construction of the originally proposed

12   226 MW CT in New Orleans) can be placed into service..

13   Since the implementation of the operating procedure to operate the circuit

14   breaker at Ninemile in the open position, MISO has considered this breaker to be

15   open in the reliability assessments that are part of the MTEP process. Therefore,

16   MISO has not identified the constraints resulting from the breaker failure at Ninemile

17   mentioned in my response above. On the other hand, the Company considers this

18   operating procedure to be temporary in nature, to be used only until the

19   implementation of the long-term solution.

20

1 Q14. ARE THE TRANSMISSION UPGRADES IDENTIFIED ABOVE AN EFFECTIVE

2 ALTERNATIVE TO LOCAL GENERATION?

3 A. No. A key function of the transmission grid is to enable the transportation of large

4 amounts of power from resources to load and/or between different regions of the

5 electric grid. While the transmission system is instrumental in facilitating the

6 movement of electric power, it cannot produce electrical energy, capacity, or much

7 needed dynamic reactive power in the DSG load pocket.

8 Thus, additional transmission upgrades aimed at increasing the import

9 capability may not have that effect unless there is also excess long-term generating

10 capacity outside of DSG. As discussed more fully in the Direct Testimony of Mr.

11 Cureington, System Planning and Operations ("SPO") forecasts that market

12 equilibrium in the MISO South region (the point at which supply, including third-

13 party resources, and demand, including appropriate planning reserves, are in balance)

14 will occur around 2022. This means that even if the Company were to invest in

15 constructing transmission with the intention of importing power into the ENO

16 footprint, it is possible there would be no excess capacity available to import on a

17 long-term basis. Therefore, relying on transmission investment could lead the

18 Company into a position of lacking required capacity at a time when the market has

19 no meaningful excess supply elsewhere in MISO.

20 Secondly, as stated in my Direct Testimony, there are significant

21 constructability issues in the New Orleans area with respect to transmission. I have

22 considerable experience with planning and constructing transmission in the New

23 Orleans area, including assisting in the restoration of the storm-damaged transmission

1   system in the greater New Orleans area. In my experience, the soil conditions,

2   obstructions, and environmental challenges tend to increase the cost of construction

3   substantially and necessitate expensive wetlands damage mitigation following the

4   construction of a transmission line. There are also rights-of-way issues, as well as

5   many above-ground obstructions and below-ground infrastructure (such as pipelines)

6   which make it very difficult to construct transmission facilities. NOPS, on the other

7   hand, can be constructed on a small footprint and on land the Company already owns.

8   The Company has not conducted detailed planning-level cost estimates for the

9   transmission upgrades identified above because these upgrades will not be necessary

10   if the 226 MW NOPS option is constructed, and because the Company would propose

11   to defer the decision on possible upgrades if the Alternative Peaker is selected.

12   However, if the Company were ordered to build transmission in lieu of NOPS, it is

13   quite possible that those estimates would increase due to the complications mentioned

14   above, and in my Direct Testimony.

15   Moreover, transmission upgrades will not add local generation to an area in

16   need of such generation (*i.e*., transmission upgrades will not replace aging local

17   generation, provide reactive power benefits, black-start capability, or storm support).

18

1   Q15.   WILL THE SOUTHEAST LOUISIANA TRANSMISSION PROJECT[10] ADDRESS

2   THE RELIABILITY ISSUES IDENTIFIED?

3   A.   This project was included in the study models utilized in the Company's transmission

4   analysis, which led to the identification of the projects needed for the mitigation of

5   NERC reliability standard violations absent the NOPS. Thus, all reliability benefits

6   for that project are captured in the analyses. This project is designed to eliminate

7   constraints in western DSG and allow for more power to be imported into DSG. It

8   will not solve reliability issues in the eastern end of DSG, including the critical

9   category P6 contingency, which will be mitigated by NOPS. By way of analogy,

10   adding additional traffic lanes on Interstate 10 between LaPlace and Kenner will not

11   ease traffic concerns in downtown New Orleans.

12

13   Q16.   HAS THE COMPANY CONDUCTED A RELIABILITY ANALYSIS USING THE

14   ASSUMPTIONS REQUESTED BY THE COUNCIL'S ADVISORS?

15   A.   Yes. The Company conducted a reliability analysis using the following assumptions

16   based on recommendations sent to ENO by the Council's Advisors:

17   -   **Requested Case A**: load flow study assuming no generation additions at the
18   Michoud site (see above in Q10, the "No NOPS" Scenario);
19
20   -   **Requested Case B1**: load flow study assuming Resource Portfolio A
21   includes the updated load forecast, 100 MW solar facility (assumed to be
22   able to output at 35% of the maximum capacity at the summer peak hour),

---

[10] The Southeast Louisiana Economic Transmission project was recommended for approval by the MISO Planning staff during the MTEP 16 economic transmission planning study process and was approved by the MISO Board of Directors as an Appendix A MTEP16 project on December 6, 2016. Details of the project can be found on slide 9 of this August 25, 2016, Economic Planning Users Group presentation: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160825/2016 0825%20EPUG%20Item%2003%20Project%20Recommendation.pdf

1   accounting for the Council's 2% DSM goal[11], and the Resource Portfolio,
2   composed of a 226 MW G-Frame combustion turbine;
3
4   -   **Requested Case B2**: load flow study assuming Resource Portfolio A
5   includes the updated load forecast, 200 MW solar facility (assumed to be
6   able to output at 35% of the maximum capacity at the summer peak hour),
7   accounting for the Council's 2% DSM goal;
8
9   -   **Requested Case C**: load flow study assuming Resource Portfolio B includes
10   the updated load forecast, 100 MW solar facility (assumed to be able to
11   output at 35% of the maximum capacity at the summer peak hour), 2% DSM,
12   and a ~128 MW generator consisting of seven peaking units; and
13
14   -   **Requested Case D**: load flow study assuming ENO's original proposal, a
15   226 MW CT (See above in Q10, "226 MW" Scenario).
16
17
18   At the outset, it should be stated that with respect to Advisor Cases B and C,

19   the NERC standards do not address the modeling of solar or DSM resources in the

20   context of long-term reliability planning.   The Company notes that DSM load

21   reductions are speculative in nature (*i.e.*, capital expenditures on DSM do not

22   guarantee load reductions) and therefore the inclusion of such load reductions in a

23   reliability analysis does not ensure that the Company will remain compliant with

24   NERC Reliability Standards if the reductions do not actually materialize. Inclusion

25   of speculative load reductions is not consistent with the conservative approach that

26   has been preferred for long-term reliability planning related to the ENO transmission

27   system.

28   Similarly, the Company has included solar resources (discounted to 35% in

29   the analysis, which represents an assumption regarding its on-peak output) in

---

[11]   The Council's 2% DSM goal involves the development of Energy Smart Program years for Year 7 and
beyond with a goal of increasing the projected savings from the Energy Smart program by 0.2% per year, until
such time as the program generates energy savings at a rate equal to 2% of annual energy sales of the Company.

1 Requested Cases B and C, but solar generation is an intermittent resource and its

2 output cannot be called upon to mitigate reliability constraints with any degree of

3 certainty. Moreover, the Company assumed in its analyses of the Requested

4 scenarios that the solar generation will all be interconnected strategically at the most

5 favorable location for the mitigation of reliability constraints on the transmission

6 system in and around DSG (*i.e*., the New Orleans East area). For example, the

7 Company selected a portfolio of three resources in its recent Renewables RFP,

8 totaling 45 MW. The first resource selected is a 20 MW solar facility located in New

9 Orleans East; the second is a 5 MW project that will be spread across the New

10 Orleans area; and the third is a 20 MW PPA with a resource that is remote from DSG

11 and Amite South. This evidences the fact that it is unlikely that a significant portion

12 of ENO's solar portfolio will be located in New Orleans East due to cost and space

13 issues, as explained by Mr. Cureington, and this uncertainty further complicates the

14 issue of how to treat solar resources in NERC reliability planning. Thus the reliability

15 benefits of solar resources are likely significantly overstated in the analysis.

16 While the inclusion of intermittent resources and speculative DSM may be

17 informative from an economic perspective, reliability planning should be predicated

18 on what can reasonably be counted on to reliably serve ENO system loads. Since the

19 Company cannot know with a reasonable degree of certainty when these resources

20 will be available and where they will be located, reliance on these uncertain resources

21 for the purposes of meeting reliability criteria creates risks for customers.

22 Notwithstanding these concerns the Company has included the assumptions in

1   Requested Cases B1, B2, and C, and the results are as follows (*See* Q10 for

2   Requested Cases A and D):

3

4   **Requested Case B1**

5   The results of the reliability assessment conducted for the Requested Case B1

6   indicates that while several reliability constraints are observed in the early study years

7   of the assessments, planned transmission projects that are expected to be in-service by

8   2020 mitigate these constraints. [12] As a result of these transmission projects and the

9   resources contemplated in Case B1, the latter study years of the Company's

10   assessment of Requested Case B1 showed no constraints on the system. In the 2019[13]

11   study year, a breaker failure at the Ninemile 230 kV substation was observed to result

12   in two 230 kV transmission line overloads. In addition, a category P6 contingency in

13   the ENO transmission grid results in no risk of cascading outages or a voltage

14   collapse. In the 2024 and 2027 study years, no constraints were observed in the

15   system that resulted from either the breaker failure or the category P6 contingency.

16

17   **Requested Case B2**

18   The results of the reliability assessment conducted for the Requested Case B2

19   indicate that several 230 kV and 115 kV lines in DSG would overload in the near-

---

[12]   Transmission upgrades in the Company's current long-term transmission plan, in particular, the Target
Appendix A MTEP17 Jefferson Parish Area Reliability Plan project, allow for the mitigation of the overloads
resulting from the failure of the 230 kV breaker at Ninemile in the 2024 study year.

[13]   It should be noted that neither the CT nor the Alternative Peaker would be in service by the summer
peak in 2019.

1 term planning horizon without additional transmission investment. Transmission

2 upgrades currently in the Company's long-term transmission plan then help to

3 mitigate these constraints, but a subset of these constraints re-appears towards the end

4 of the 10-year planning horizon under the assumptions incorporated into Requested

5 Case B2.

6 In the 2019 study year, a breaker failure at the Ninemile 230 kV substation

7 was observed to result in three 230 kV transmission line overloads and one 115 kV

8 transmission line overload. In addition, a category P6 contingency in the ENO

9 transmission grid results in the cascading outages of six 115 kV transmission

10 branches in the ENO transmission network resulting in a voltage collapse and wide-

11 spread load shedding in the New Orleans area.

12 In the 2024 study year, planned transmission upgrades result in no overloads

13 in the transmission system resulting from the breaker failure event; similarly, the

14 category P6 double contingency is not expected to result in cascading outages or

15 severe voltage constraints in New Orleans, but could require some load shedding to

16 mitigate violations.

17 In the 2027 study year, the 230 kV breaker failure contingency at Ninemile

18 would result in two 230 kV transmission lines to overload. However, the Requested

19 Case B2 scenario is not expected to result in severe transmission constraints

20 following the category P6 contingency mentioned above, thus avoiding the cascading

21 outages and voltage collapse, but could require some load shedding to mitigate

22 violations. Projects required to be constructed in order to mitigate the constraints

23 observed in the system in the 2027 study year are as follows:

1   **Table 3: "Requested Case B2" Transmission Upgrades**

Project	Voltage	Total Project Cost	Need-by Date
Almonaster to Curran Line Upgrade	230kV	$18,050,000	Summer 2027
Southport to Joliet Line Upgrade	230kV	$5,125,000	Summer 2027

2

3   **Requested Case C**

4   The results of the reliability assessment conducted for the Requested Case C

5   indicates that while several reliability constraints are observed in the early study years

6   of the assessments, planned transmission projects that are expected to be in-service by

7   2020 mitigate these constraints. As a result of these transmission projects and the

8   resources contemplated in Case C, the latter study years of the Company's assessment

9   of Requested Case C showed no constraints on the system. In the 2019 study year, a

10   breaker failure at the Ninemile 230 kV substation was observed to result in three 230

11   kV transmission line overloads and one 115 kV transmission line overload.   In

12   addition, a category P6 contingency in the ENO transmission grid results in no risk of

13   cascading outages or a voltage collapse. In the 2024 and 2027 study years, no

14   constraints were observed in the system that resulted from either the breaker failure or

15   the category P6 contingency.

16

17   Q17.   PLEASE SUMMARIZE THE RESULTS OF THE REQUESTED CASES.

18   A.   As stated earlier, with respect to Requested Case A, (the "No NOPS" scenario in

19   Q10), the grid will not remain reliable if no local generation is added and the

1   Company will need to construct costly transmission upgrades to comply with NERC

2   requirements. Under this scenario, the Company's service territory would face the

3   risk of cascading outages.

4   Both Requested Cases B1 and C are reliable in the long-term planning horizon

5   after other transmission projects, which are already in the Company's long-term

6   transmission plan, are placed into service. Requested Case B2 will require

7   transmission upgrades in order to remain NERC compliant throughout the planning

8   horizon.

9   Regarding Requested Case D (the "226 MW" scenario in Q10), adding the CT

10   will eliminate all reliability issues within the 10-year planning horizon without the

11   need for additional transmission projects.

12

13   Q18. DO YOU CONTEND THAT SOLAR AND DSM HAVE NO RELIABILITY

14   VALUE?

15   A.   No. The effectiveness of solar resources to meet the reliability need in DSG depends

16   largely on the characteristics, point(s) of interconnection, and capacity associated

17   with such resources. Given the intermittent nature of the renewable resources that will

18   be practical in an urban environment like the New Orleans metropolitan area, the

19   amount of dependable power that such resources will be able to produce at the

20   summer and winter peak hours is unknown at this time. In addition, the location of a

21   solar resource will have a significant effect on any reliability benefits that it may

22   produce and ENO does not know where the solar resources assumed in Requested

23   Cases B through C will be located. Thus, while intermittent resources will likely

1   have some long-term reliability value, it is clear that in this case, such resources do

2   not provide the certainty that a local gas-fired generator under the Company's control

3   would provide. Thus, while these renewable resources could provide economic and

4   environmental benefits, they cannot offer the reliability benefits of a local gas-fired

5   resource to the Company's customers.

6

7   **IV.   BENEFITS OF LOCAL GENERATION**

8   Q19. IN YOUR DIRECT TESTIMONY, YOU HIGHLIGHTED THE LOCAL

9   RELIABILITY BENEFITS OF LOCALLY SITED GENERATION. PLEASE

10   REITERATE THOSE BENEFITS IN A SUMMARY MANNER.

11   A.   As explained more fully in my Direct Testimony, siting a new resource at a location

12   that enhances reliability is consistent with the best interest of customers. Reliability

13   is enhanced when that location is in close proximity to the load that the generation

14   resource serves. In sum, constructing NOPS in its proposed location would enhance

15   reliability in the following ways:

16   • Making the region less dependent on importing power to serve load;
17

18   • Reducing transmission usage in the area and thereby allowing for
19   more flexible outage scheduling to facilitate maintenance activities
20   on the system;
21

22   • Providing reactive power support to the region; and
23

24   • Providing additional operational flexibility during system
25   restorations following major storm events such as hurricanes.
26

27   Q20. WOULD THE CONSTRUCTION OF THE ORIGINAL UNIT PROPOSED, THE

28   226 MW CT, CREATE SIGNIFICANT RELIABILITY BENEFITS?

1   A.   Yes. The CT originally proposed would have more benefits than a unit with a lower

2   output in the following ways:

3   -   **Operational Flexibility**: a larger unit would result in less dependence on

4   transmission assets to import power. This reduced dependence on the electric

5   grid to serve the Company's loads resulting from lower levels of power flows

6   on the transmission lines and transformers makes it easier to schedule planned

7   outages for maintenance of transmission facilities or generators in the area.

8   -   **Reactive Capability**: The reactive capability of a machine defines its ability

9   to regulate the flow of reactive power to the electric network in order to

10   support voltages in the area and maintain a transmission network stiff enough

11   to support the large starting currents required to switch on large industrial

12   motors. Generators are particularly useful because they can increase or reduce

13   the reactive injection into the power system quickly and respond to sudden

14   system changes in the grid, such as the loss of another generator or

15   transmission asset such as a line, a transformer, or a capacitor bank. Thus,

16   increasing the reactive capability of a generator increases the reliability of the

17   surrounding transmission system and enhances its ability to appropriately

18   respond to system disturbances. The 226 MW CT would provide about 50%

19   more reactive power than the Alternative Peaker.

20   -   **Economic Development**: A larger NOPS resource is well positioned to

21   support future economic development in ENO. The Company reviewed at

22   least seven independent requests for block load additions in the New Orleans

23   area in 2016. Requests varied in scope, but some requests were as large as 40

1   MW for a single project. A larger resource in close proximity to a potential

2   load interconnection reduces the likelihood that commercial/industrial growth

3   in New Orleans will be inhibited by transmission expenses associated with

4   delivering power from more remote resources to these loads.

5   -   **Transmission Capability**: The CT would reduce the need to import power

6   into New Orleans. One MW produced at NOPS will not only reduce the DSG

7   interface flows by a little more than one MW (to account for losses in the

8   transmission system resulting from the flow of the imported power), but will

9   also reduce the need for imports into New Orleans via the key transmission

10   river crossings over the Mississippi river. Once the power flow through these

11   river-crossing transmission lines reaches the rated capacity of these lines,

12   increasing the import capability into ENO will likely require the construction

13   of a new river-crossing transmission line as the existing transmission lines

14   crossings the river share the same tower, which makes scheduling outages to

15   both lines in order to carry out construction work very difficult to obtain. If

16   the proposed 226 MW NOPS interconnects at the Michoud facility, these

17   river-crossing transmission lines are not anticipated to limit the import

18   capability into the ENO area for at least 10 years.

19

20   Q21. WOULD THE ALTERNATIVE PEAKER STILL PROVIDE SOME OF THE

21   BENEFITS OFFERED BY THE ORIGINALLY PROPOSED CT?

22   A.   Yes.   The Alternative Peaker will provide all of the aforementioned reliability

23   benefits, albeit to a lesser degree because its output is 100 MW lower than the

1   original 226 MW NOPS CT. However, as stated above, the Alternative Peaker will

2   likely satisfy NERC reliability requirements for the planning term. Additionally, it

3   should be noted that the Alternative Peaker also includes black-start capability, which

4   could enable it to be even more beneficial in the event of wide-spread transmission

5   system outages during a major storm.

6

7   Q22.   PLEASE ELABORATE ON THE CURRENT BLACK-START PLAN AND HOW

8   THE ALTERNATIVE PEAKER'S BLACK-START CAPABILITY COULD

9   BENEFIT THE CITY OF NEW ORLEANS.

10   A.   The Company's current black-start plan involves the commencement of the

11   restoration of power from the Waterford Unit 4 black-start resource, which can then

12   be used to energize a cranking path to the Waterford 1 or Waterford 2 resource.

13   Power from the Waterford natural gas-fired resources can then be used to continue

14   the restoration of power by energizing the Waterford – Ninemile transmission

15   corridor. If necessary or possible, the Ninemile Units 4 or 5 can be started with the

16   restoration of power in the Ninemile switchyard. The restoration of electric supply

17   can then continue along the Ninemile – Derbigny – Tricou – Arabi – Michoud

18   transmission path to bring power into the city.

19   While this black-start procedure is certainly robust and sufficient to provide

20   power to the Company's customers if a complete loss of electric power supply were

21   to occur, the plan still relies upon the transmission grid to import power into the ENO

22   footprint from Ninemile. Any damage to the transmission grid, either from the

23   Ninemile facility into the city or from the Waterford facility towards Ninemile would

1   impair the Company's ability to provide electric service to ENO customers if a

2   complete loss of electric power supply were to occur. On the other hand, the ability

3   of the Alternative Peaker to black-start greatly reduces ENO's dependence on the

4   transmission grid for restoring electric service to customers. Provided that the

5   distribution system is sufficiently robust to serve load, the ability to black-start the

6   Alternative Peaker enables the Company to restore power to loads from this resource,

7   which will be in close electrical proximity to the electric demand, enabling much

8   more effective voltage and frequency response during the black-start process. Thus,

9   the Alternative Peaker's ability to black-start will greatly enhance the Company's

10   ability to restore electric service, should a complete loss of service on the electric

11   system occur.

12

13   Q23. PLEASE PROVIDE AN UPDATE REGARDING THE COMPANY'S CURRENT

14   PLAN TO RECEIVE NETWORK RESOURCES INTERCONNECTION SERVICE

15   ("NRIS") FOR THE ALTERNATIVE PEAKER.

16   A.   The Company has reduced the amount of Network Resource Interconnection Service

17   ("NRIS") requested in the MISO generator interconnection process to reflect the

18   Alternative Peaker. The Company's interconnection request is part of the pool of

19   resources submitted for evaluation in the August 2016 DPP cycle and which is now in

20   Phase II of a possible three Phases. The Company has received assurances from

21   MISO that this substitution in resources does not produce an impact to the system that

22   is more adverse than the original interconnection request, *i.e.*, the impact on the

23   transmission system estimated for the Alternative Peaker is either equal to or less than

1   that resulting from the original 226 MW interconnection request. This means that the

2   Company's interconnection request can proceed through the interconnection process

3   without having to re-study any of the prior deliverability assessments performed in

4   Phase I of the August 2016 DPP process.

5

6   Q24.   DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

7   A.   Yes, at this time.

AFFIDAVIT

STATE OF MISSISSIPPI

COUNTY OF __Hinds__

     NOW BEFORE ME, the undersigned authority, personally came and appeared, **CHARLES W. LONG,** who after being duly sworn by me, did depose and say:

     That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.
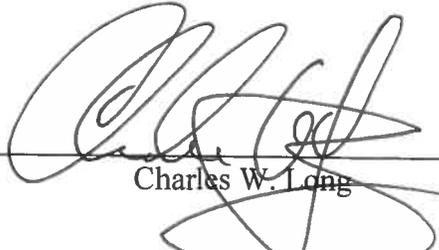
_____
Charles W. Long

SWORN TO AND SUBSCRIBED BEFORE ME
THIS _15th_ DAY OF JUNE, 2017

_____
NOTARY PUBLIC

My commission expires: _6/22/20_

ALETTA B WALKER
NOTARY PUBLIC
ID No. 116794
Commission Expires
Jun 22, 2020
STATE OF MISSISSIPPI
MADISON COUNTY
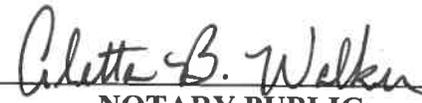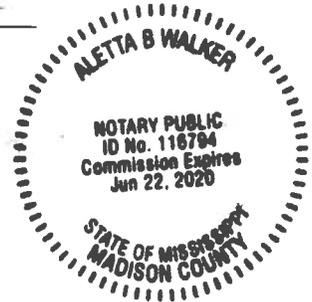
Entergy®

Results of ENO's Transmission Analysis and Advisor Requested Analysis

July, 2017

ENO's Updated Transmission Analysis

Thermal and voltage reliability violations that were observed on the transmission system for the following scenarios are provided in the following slides for the 2019-2027 time horizon:

- No NOPS resource
- NOPS modeled at 110 MW (approximately the capacity of the seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine generator sets)
- NOPS modeled at 226 MW (approximately the capacity of the G-frame combustion turbine-generator)

- All of the above analyses assumes a 350 MW resource (comprising of two CTs) at the Washington Parish Energy Center* at Bogalusa.

- All MTEP16 Appendix A and MTEP17 target Appendix A transmission projects in the study region were included in these analyses.

- Updated load forecasts were incorporated into this transmission reliability assessment.

* This resource is included in the Entergy Operating Companies' long-term resource plan

Results of reliability analysis

No NOPS resource

The following reliability constraints are observed in the absence of any generator at the Michoud substation:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.

- The overloads range from approx. 121% in 2019[1] to 102% in 2022 and rise in magnitude to approx. 109% in 2027.

- These constraints necessitate the upgrades of approx. 18.1 miles of transmission lines in the New Orleans area.

   - Scheduling outages for construction work is becoming increasingly difficult in the New Orleans area.

Legend:

⭕ Geographical extent of reliability constraints resulting from the breaker failure contingency
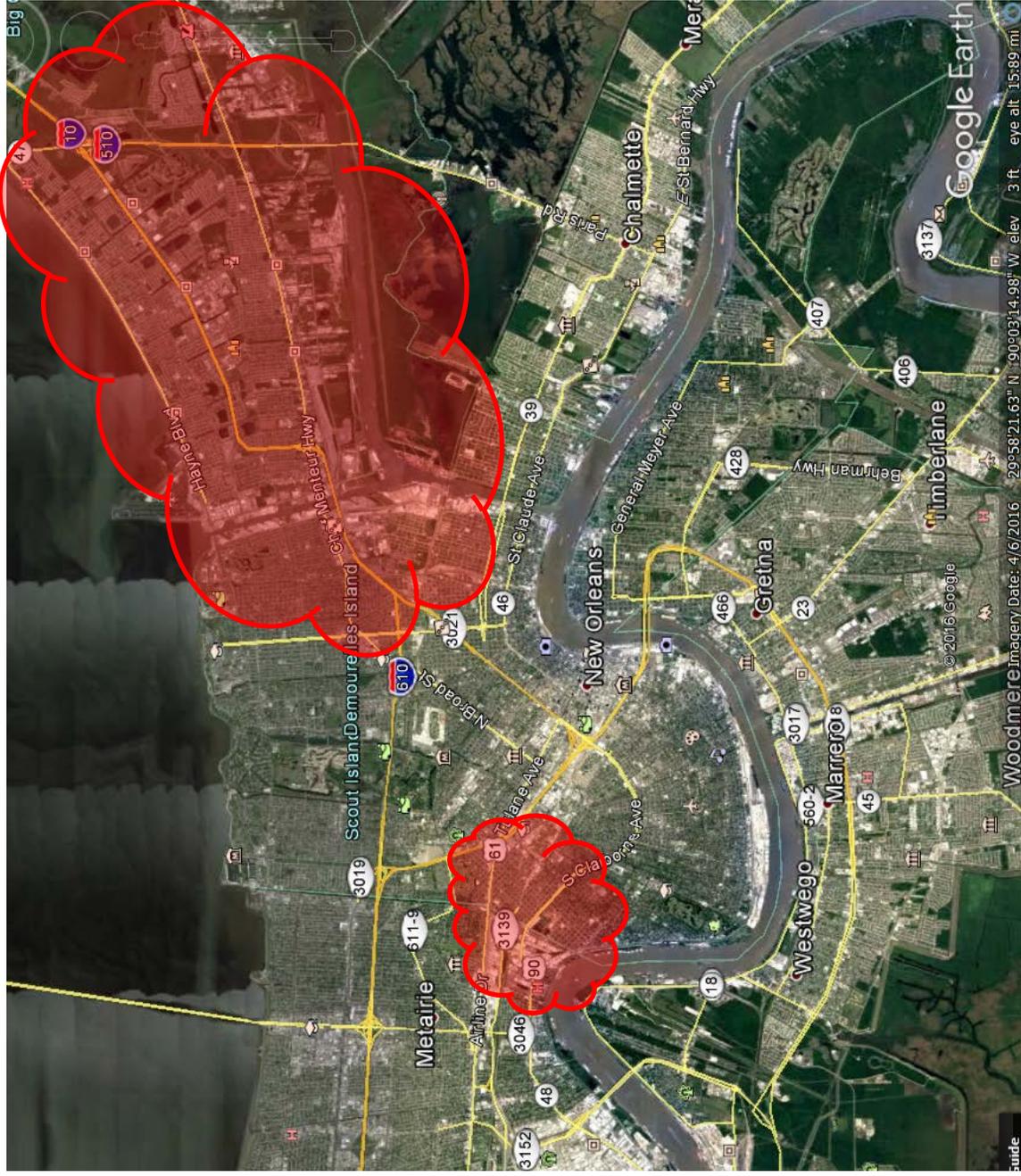
[1]Planned transmission upgrades help reduce the overload in 2022.

Results of reliability analysis

No NOPS resource

The following reliability constraints are observed in the absence of any generator at the Michoud substation:

- Two sequential outages (a category P6 NERC contingency) results in a severely overloaded transmission line (shown in the region encircled in red).

- Zone 3 tripping of this line results in similar severely overloaded lines (shown in yellow) which eventually result in cascading outages and rapid load shedding in the region shown in orange.

- These constraints necessitate the upgrades of approx. 18 miles of transmission lines in the New Orleans area.

  - Scheduling outages for construction work is becoming increasingly difficult in the New Orleans area.
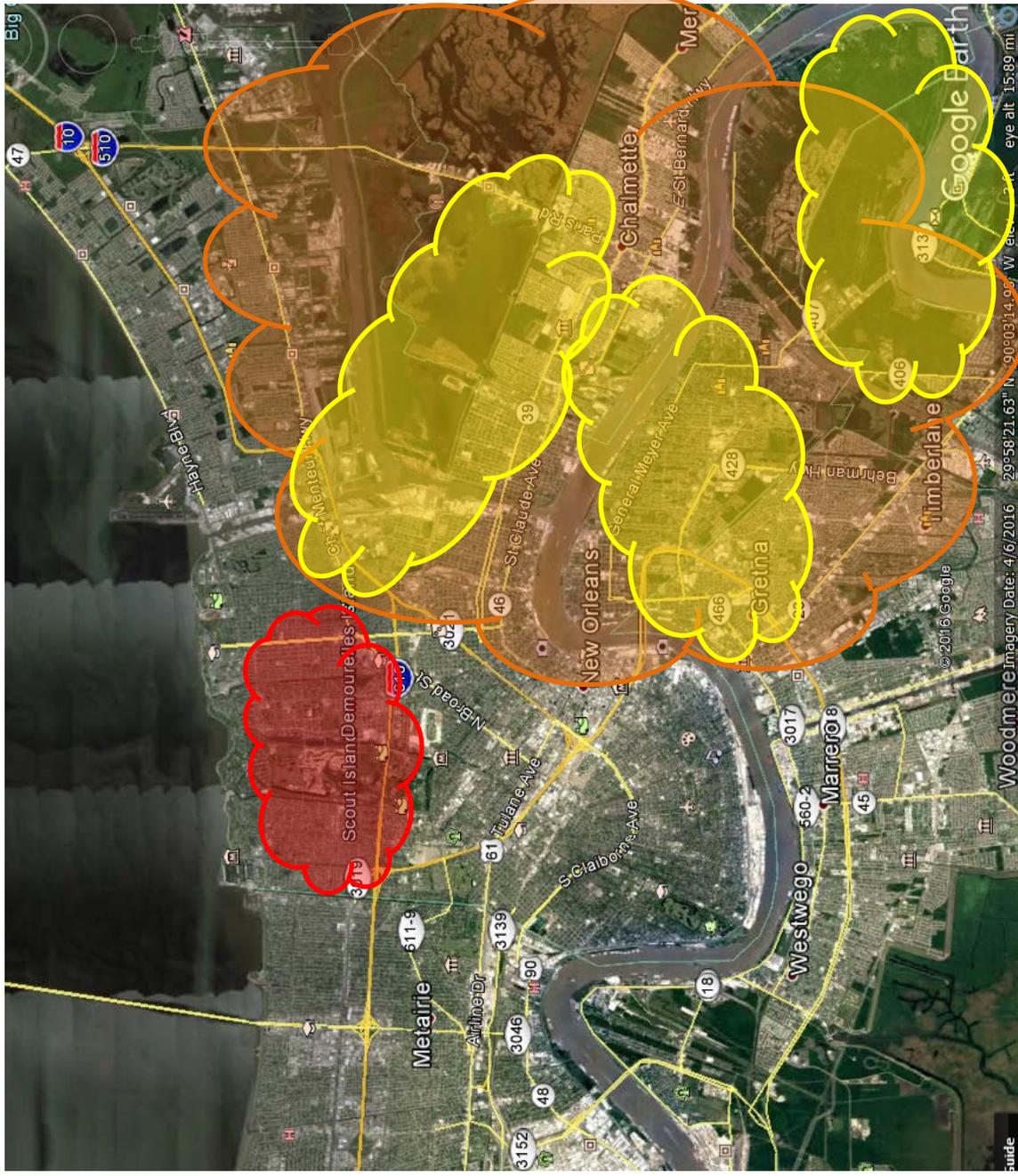
Legend:

- Region of anticipated load shed
- Secondary overload
- Primary overload

Results of reliability analysis

No NOPS resource

The following transmission upgrades are required to be constructed in the absence of any generator at the Michoud substation:

Project	Voltage	Total Project Cost	Need-by Date
Avenue C to Pauger Line Upgrade	115kV	$21,050,000	Summer 2021
Chalmette to Patterson Line Upgrade	115kV	$12,979,000	Summer 2021
Michoud to Curran Line Upgrade	230kV	$100,000	Summer 2027
Almonaster to Curran Line Upgrade	230kV	$18,050,000	Summer 2021
Southport to Joliet Line Upgrade	230kV	$5,125,000	Summer 2021

Results of reliability analysis

110 MW NOPS resource

The following reliability constraints are observed if a 110 MW generator were to interconnect at the Michoud substation:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.

- The overloads are approx. 102% in 2027.

- These constraints necessitate the upgrades of approx. 11.5 miles of transmission lines in the New Orleans area.

  - Scheduling outages for construction work is becoming increasingly difficult in the New Orleans area.
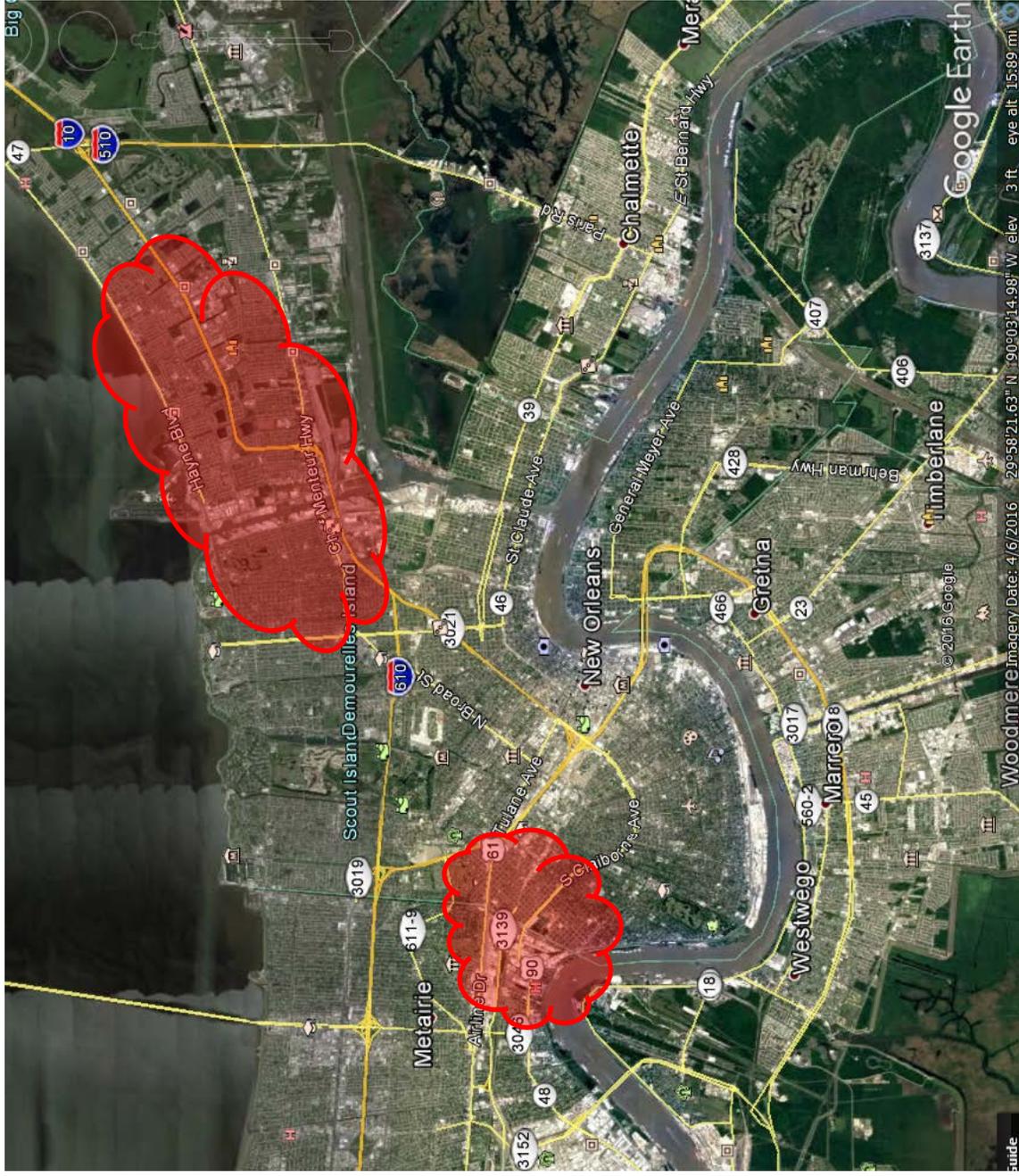
Legend:

O Geographical extent of reliability constraints resulting from the breaker failure contingency

Results of reliability analysis

110 MW NOPS resource

The following reliability constraints are observed in the absence of any generator at the Michoud substation:

- Two sequential outages (a category P6 NERC contingency) no longer results in any overloads in the new Orleans area.

- While a 110 MW resource at Michoud will still requires upgrades to the system resulting from the breaker failure, this resource option is effective in preventing cascading outages in the New Orleans area.
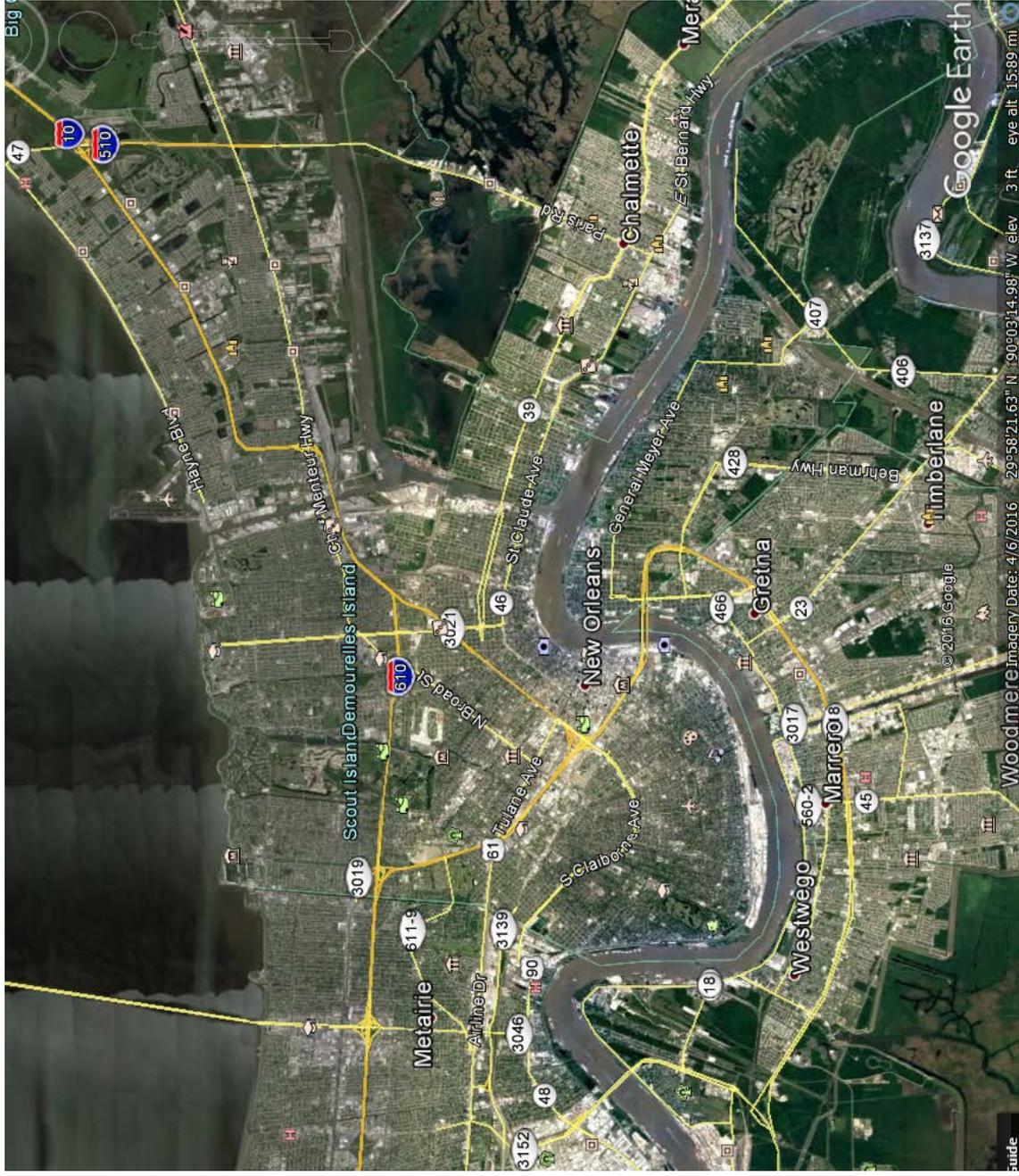
Results of reliability analysis

110 MW NOPS resource

The following transmission upgrades are required to be constructed if a 110 MW generator were to be interconnected at Michoud:

Project	Voltage	Total Project Cost	Need-by Date
Almonaster to Curran Line Upgrade	230kV	$18,050,000	Summer 2027
Southport to Joliet Line Upgrade	230kV	$5,125,000	Summer 2027

Results of reliability analysis

226 MW NOPS resource

If a 226 MW generator were to interconnect at the Michoud substation:

- None of the constraints mentioned above in the 2022, 2024, or the 2027 study years were observed

- No upgrades would be required if NOPS were to interconnect to the transmission grid at Michoud as scheduled

Advisor Requested Cases

Thermal and voltage reliability violations that were observed on the transmission system for the following scenarios are provided in the following slides for the 2019-2027 time horizon:

- Requested Case B1 (100 MW solar resource, the Council's 2% DSM goal[1] plus the 226 MW G-Frame CT)

- Requested Case B2 (100 MW solar resource, the Council's 2% DSM plus an additional 100 MW solar resource)

- Requested Case C (100 MW solar resource, the Council's 2% DSM goal plus a 128 MW resource which represents seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine generator sets)

- All of the above analyses assumes a 350 MW resource (comprising of two CTs) at the Washington Parish Energy Center* at Bogalusa.

- All MTEP16 Appendix A and MTEP17 target Appendix A transmission projects in the study region were included in these analyses.

- Updated load forecasts were incorporated into this transmission reliability assessment.

[1]The Council's 2% DSM goal involves the development of Energy Smart Program years by 0.2% per year, until the program generates energy savings at a rate equal to 2% of annual energy sales of the Company.

* This resource is included in the Entergy Operating Companies' long-term resource plan

Results of reliability analysis

Requested Case B1

The following reliability constraints are observed in 2019 if the Requested Case B1 were implemented:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the three regions encircled in red in the map.

- The worst overload is approx. 108% in 2019 for a 230 kV transmission line.

- The two sequential outages (a category P6 NERC contingency) do not result in a risk of cascading outages, though load may potentially have to be curtailed under this double contingency scenario.

2019 Study Year Constraints

Legend:

Geographical extent of reliability constraints resulting from the breaker failure contingency
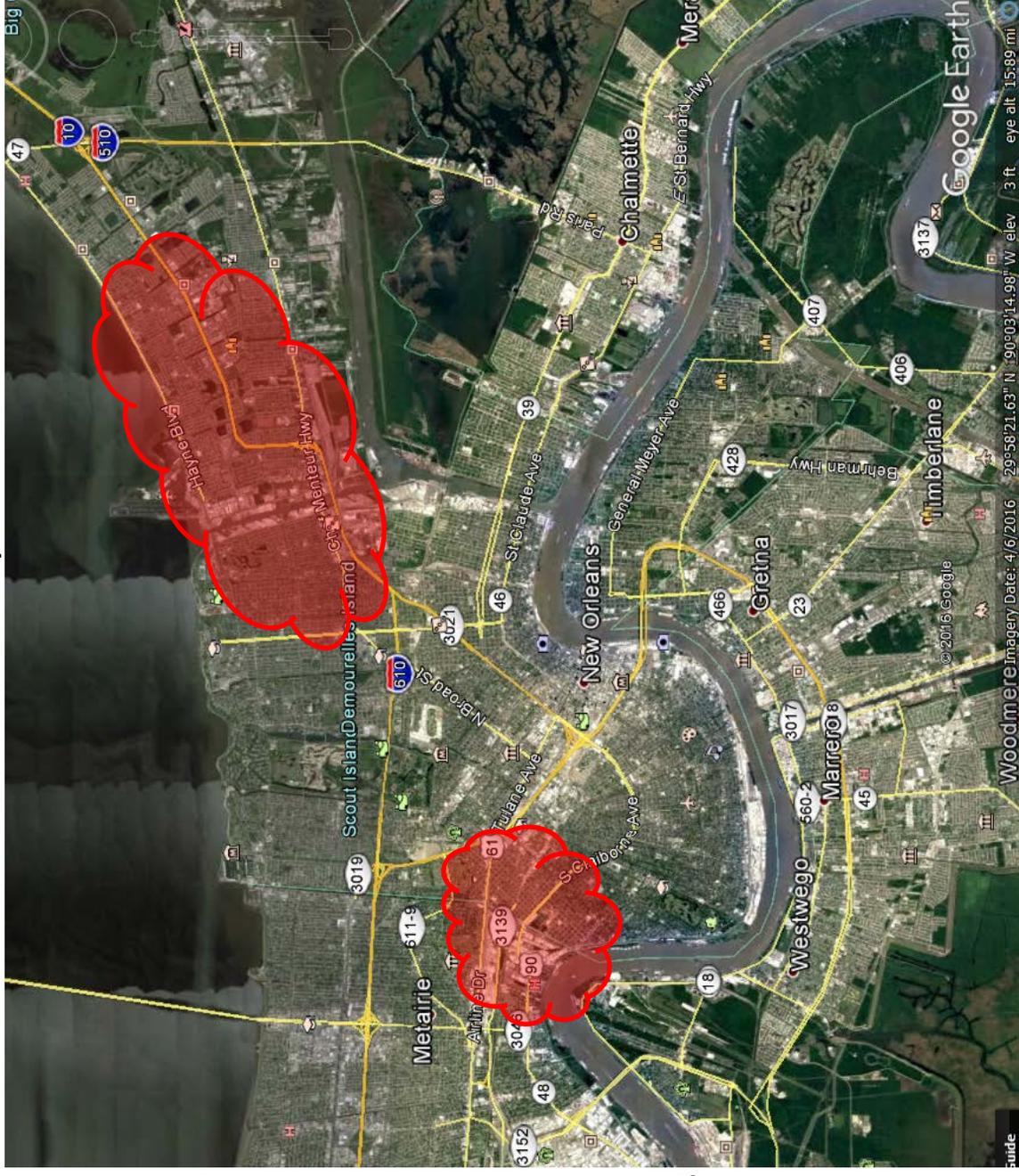
Results of reliability analysis

Requested Case B1

- However, planned transmission upgrades that are expected to be in-service by 2020 will help to reduce the loading on the transmission system beyond 2020.

- As a result, no transmission constraints are observed in the transmission system, from either the breaker failure contingency or the category P6 contingency, beyond 2020 if Requested Case B1 were to be implemented.

- Therefore, no transmission upgrades are necessary if Requested Case B1 were to be implemented.

Results of reliability analysis

Requested Case B2

2019 Study Year Constraints

The following reliability constraints are observed in 2019 if the Requested Case B2 were implemented:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.

- The worst overload is approx. 117% in 2019 for a 230 kV transmission line.

- Two sequential outages (a category P6 NERC contingency) results in a severely overloaded transmission line (shown in the region encircled in purple).

- Zone 3 tripping of this line results in similar severely overloaded lines (shown in yellow) which eventually result in cascading outages and rapid load shedding in the region shown in orange.

Legend:

⬭ Geographical extent of reliability constraints resulting from the breaker failure contingency

Results of reliability analysis

Requested Case B2

2027 Study Year Constraints
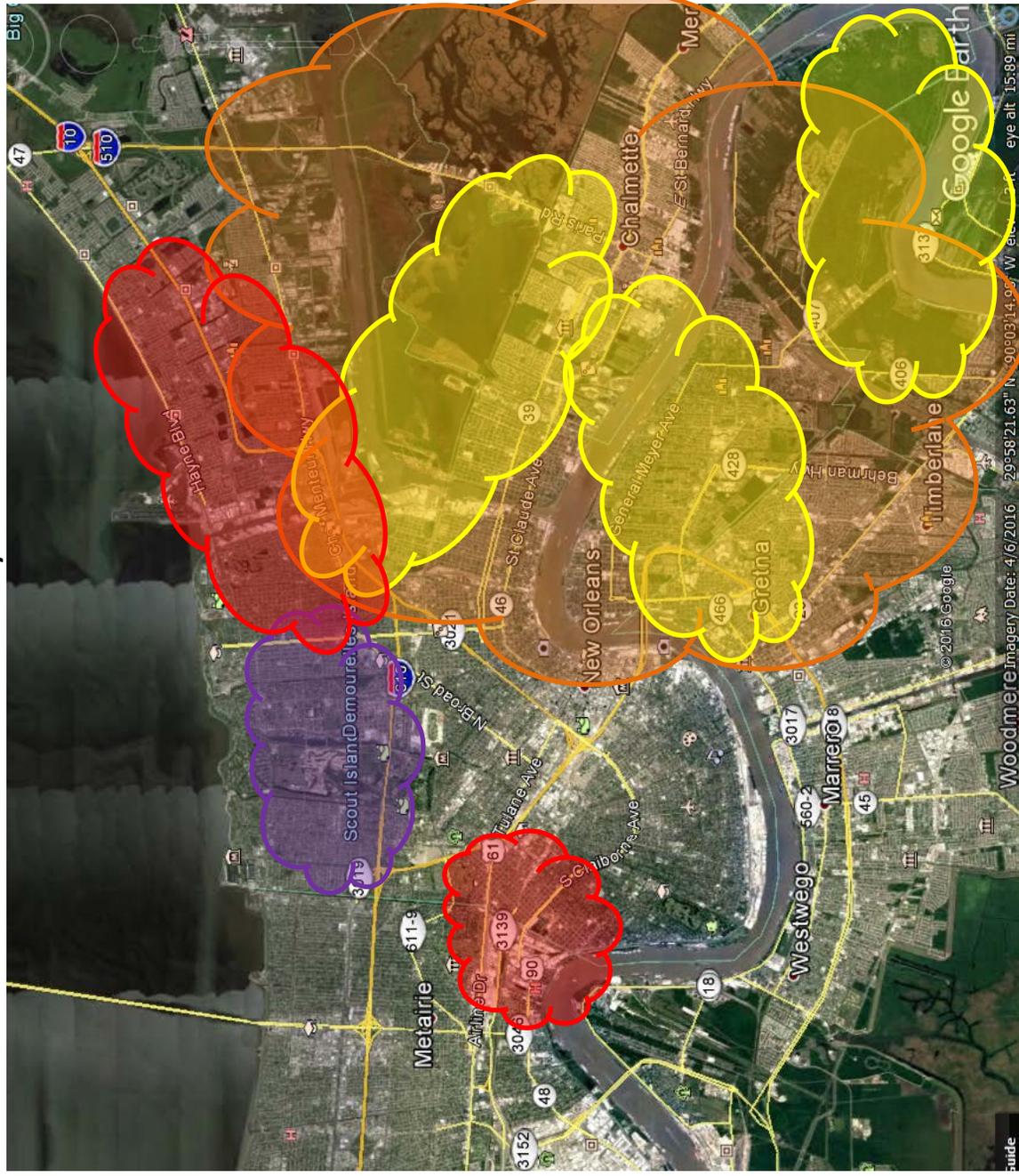
- However, planned transmission upgrades that are expected to be in-service by 2020 help to reduce the loading on the transmission system beyond 2020.

- The two residual constraints that remain in the system after 2020 under the Requested Case B2 is the contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.

- The worst overload is approx. 105% in 2027 for a 230 kV transmission line.

- Beyond 2020, the Requested Case B2 is also effective in preventing cascading outages in the New Orleans area resulting from the P6 contingency, though there may potentially be a risk of load curtailment under this double contingency scenario.
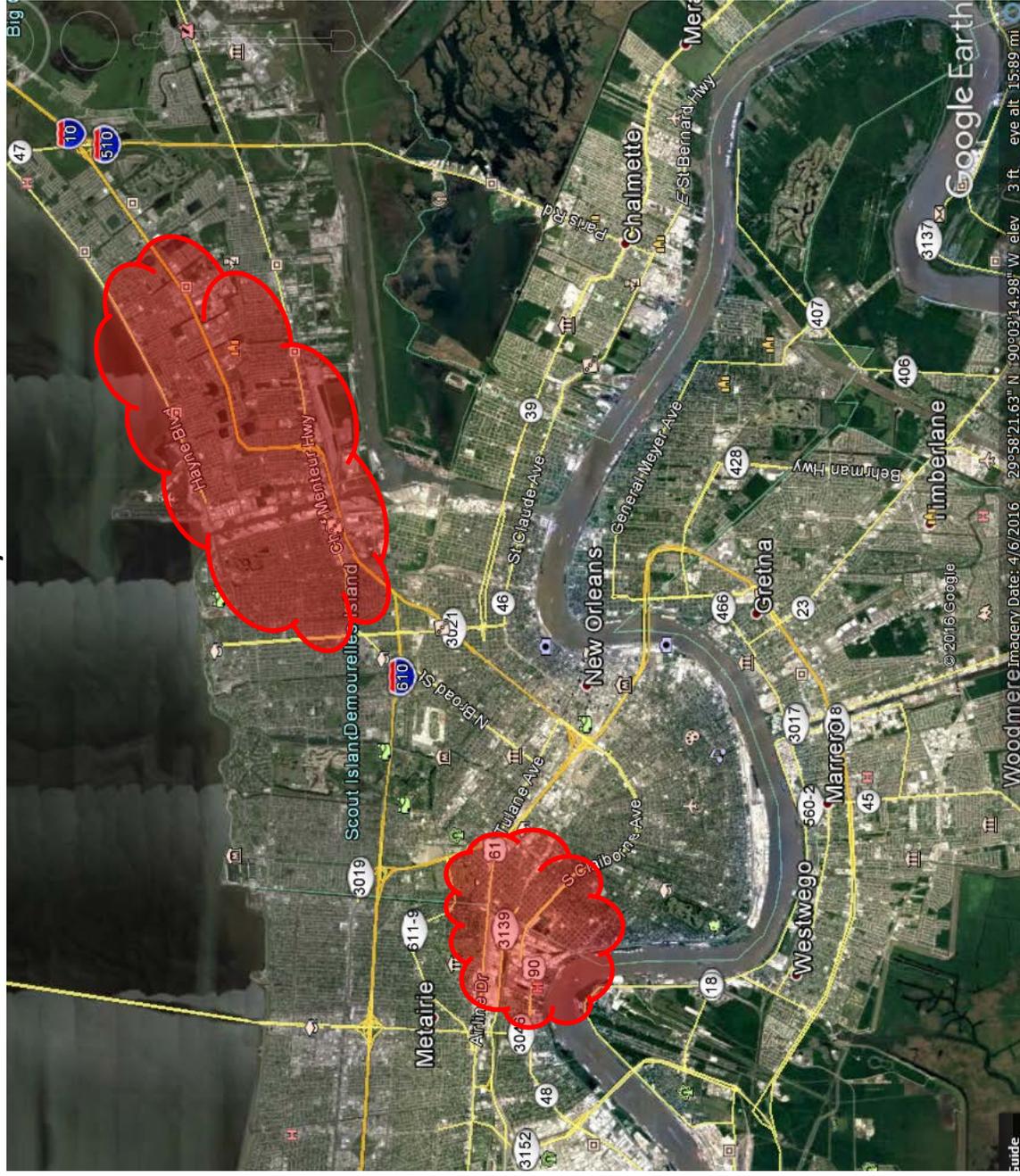
Results of reliability analysis

Requested Case B2

To mitigate the remaining constraints resulting from the breaker-failure contingency, the following transmission upgrades are required to be constructed if the Requested Case B2 were to be implemented:

Project	Voltage	Total Project Cost	Need-by Date
Almonaster to Curran Line Upgrade	230kV	$18,050,000	Summer 2027
Southport to Joliet Line Upgrade	230kV	$5,125,000	Summer 2027

Results of reliability analysis

Requested Case C

The following reliability constraints are observed in 2019 if the Requested Case C were implemented:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the three regions encircled in red in the map.

- The worst overload is approx. 111% in 2019 for a 230 kV transmission line.

- The two sequential outages (a category P6 NERC contingency) do not result in a risk of cascading outages, though load may potentially have to be curtailed under this double contingency scenario.

2019 Study Year Constraints

Legend:

◯ Geographical extent of reliability constraints resulting from the breaker failure contingency

Results of reliability analysis

Requested Case C

- However, planned transmission upgrades that are expected to be in-service by 2020 help to reduce the loading on the transmission system beyond 2020.

- As a result, no transmission constraints are observed in the transmission system, from either the breaker failure contingency or the category P6 contingency, beyond 2020 if Requested Case C were to be implemented.

- Therefore, no transmission upgrades are necessary if Requested Case C were to be implemented.

BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

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

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

BLISS M. HIGGINS

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JULY 2017

TABLE OF CONTENTS

GLOSSARY OF ACRONYMS AND POLLUTANTS

BACT	Best Available Control Technology
CAA	Clean Air Act
CASAC	Clean Air Scientific Advisory Committee
CNO	Council of the City of New Orleans
CO	Carbon monoxide
CO_2	Carbon dioxide
CT	Combustion turbine
CUP	Coastal Use Permit
ENO	Entergy New Orleans
EPA	United States Environmental Protection Agency
GHG	Greenhouse gases
HAP	Hazardous Air Pollutant
LDEQ	Louisiana Department of Environmental Quality
LDNR	Louisiana Department of Natural Resources
LPDES	Louisiana Pollutant Discharge Elimination System
LTAP	Louisiana Toxic Air Pollutant
MACT	Maximum Achievable Control Technology
MSA	Metropolitan Statistical Area
MW	Megawatt
NAAQS	National Ambient Air Quality Standard
NCEA	National Center for Environmental Assessment

NESHAP	National Emission Standards for Hazardous Air Pollutants
NOPS	New Orleans Power Station
NO_x	Nitrogen oxides
NO_2	Nitrogen dioxide
NSPS	New Source Performance Standard
O_3	Ozone
Pb	Lead
PM	Particulate Matter
PM_{10}	Particulate matter 10 microns or less in diameter
$PM_{2.5}$	Particulate matter 2.5 microns or less in diameter
PSD	Prevention of Significant Deterioration
RICE	Reciprocating Internal Combustion Engine
SIL	Significant Impact Level
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SWPPP	Stormwater Pollution Prevention Plan
USACE	United States Army Corps of Engineers
VOC	Volatile Organic Compound

1		**I. INTRODUCTION AND QUALIFICATIONS**
2		**A. Introduction**
3	Q1.	PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.
4	A.	My name is Bliss M. Higgins. My business address is 8235 YMCA Plaza Drive, Baton
5		Rouge, Louisiana 70810.
6		
7	Q2.	BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?
8	A.	I am currently employed by Ramboll Environ Holdings ("Ramboll"), an international
9		environmental consultancy. I have been employed by Ramboll or its predecessor,
10		ENVIRON International Corporation, since June 2002. I am a Principal of the firm and I
11		work as an environmental consultant, primarily in the areas of environmental permitting
12		and regulatory compliance.
13		
14		**B. Qualifications**
15	Q3.	WHAT IS YOUR EDUCATIONAL BACKGROUND?
16	A.	My formal education was 100% Louisiana. I attended public elementary schools in New
17		Orleans, and later in St. Tammany Parish, then graduated Valedictorian from a parochial
18		high school in Covington. I then attended undergraduate school and graduate school at
19		Louisiana State University ("LSU") in Baton Rouge. I have a B.S. in Professional
20		Geology from LSU. I subsequently attended graduate school in Geology, until leaving
21		school to become a full-time mother with my first child, and later attended additional

1   graduate-level chemistry and biochemistry courses as a non-matriculating student while

2   working full-time at LSU as a Research Assistant in the Biochemistry Department.

3

4   Q4.   PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE, BEGINNING

5   WITH YOUR EMPLOYMENT AT THE LOUISIANA DEPARTMENT OF

6   ENVIRONMENTAL QUALITY.

7   A.   The foundation of my expertise in air quality and other environmental regulatory

8   programs was built during my employment from 1990 to 2002 at the Louisiana

9   Department of Environmental Quality ("LDEQ"), the agency responsible for

10   implementing all state and federal air quality laws and regulations in Louisiana, a state

11   which is home to a very large and diverse industrial base. During that time, I worked

12   extensively in air quality program development and implementation. I played a lead role

13   in developing and implementing the Louisiana air toxics standards and program, and was

14   the author of the Louisiana air toxics regulation. I was also responsible for developing

15   the Louisiana air permitting regulations for preconstruction and operating permits,

16   including authoring the regulations to implement the federal operating permit program

17   under Title V of the federal Clean Air Act ("CAA") and securing the U.S. Environmental

18   Protection Agency ("EPA") approval of those regulations. I was also actively engaged in

19   the Department's enforcement program and activities.

20   While employed at LDEQ, my work included detailed permitting, compliance and

21   enforcement reviews for hundreds of major facilities across the state, including numerous

22   electric power plants. I began my work there at the entry staff level in the Air

1   Enforcement Division. I was subsequently promoted to supervisor and manager levels for

2   various programs within the Air Division. While serving as the Coordinator of the Air

3   Toxics Program, I reviewed compliance with Louisiana air toxic ambient air standards

4   for all major sources subject to the standards. In this position, I was also responsible for

5   the coordination and implementation of the federal National Emission Standards for

6   Hazardous Air Pollutants ("NESHAP") standards. I served as Program Manager of the

7   Air Permits Program from 1997 to 1999. When the Department was reorganized in 1999,

8   I served as Environmental Manager of the Industrial Permits Section responsible for

9   multimedia permitting (air, water, and waste permitting) for industrial sources, including

10   power plants. These positions included the responsibility for reviewing air permit

11   applications and air permits to ensure that all applicable regulatory requirements and all

12   provisions of both the Title V and Prevention of Significant Deterioration ("PSD")

13   programs were properly applied and implemented.

14   My work at LDEQ also involved the development, implementation, interpretation

15   and application of federal air quality, water quality and other permitting requirements,

16   regulations, emissions standards, policy and guidance on a daily basis for facilities of all

17   industrial types and sizes. In addition, over the course of my employment, I worked

18   extensively with air regulators across the country at the national level to respond to and

19   influence federal programs and initiatives.

20

1   Q5.   AFTER SERVING AS A PROGRAM MANAGER AT LDEQ, IN WHAT CAPACITY

2   DID YOU NEXT SERVE?

3   A.   In February 2000, I was appointed by Governor Mike Foster to serve as Assistant

4   Secretary of the LDEQ Office of Environmental Services, and was responsible for final

5   permit decision making for all permit actions taken by the Department, including air

6   quality, water, and hazardous waste permits. I served in that position until January 2002.

7

8   Q6.   HAVE YOU SERVED ON ANY EPA OR OTHER GOVERNMENT ADVISORY

9   COMMITTEES RELATED TO AIR QUALITY AND AIR PERMITTING?

10   A.   Yes, many. I am nationally recognized as having been an active participant in the

11   implementation of Titles III and V of the Clean Air Act Amendments of 1990, which

12   establish the federal hazardous air pollutant and air operating permit programs.   In

13   recognition of my expertise, I was selected by EPA and by my state colleagues to serve

14   on numerous regulatory and policy advisory committees and workgroups. For example, I

15   served on EPA stakeholder advisory groups and workgroups related to New Source

16   Review Reform and Title V program development. I also served on several workgroups

17   to develop several federal NESHAP known as Maximum Achievable Control

18   Technology ("MACT") standards and other federal air emission standard regulations,

19   including the MACT standards for petroleum refineries, pulp and paper mills, and

20   chemical manufacturing facilities, and the Consolidated Air Rule for the chemical

21   manufacturing industry. I served on a subcommittee of the EPA CAA Advisory

22   Committee, a Federal Advisory Committee, to advise EPA on the development of the

1   Integrated Air Toxics Strategy. I accepted an invitation from the U. S. Congress

2   Committee on Commerce, Subcommittee on Oversight and Investigations to provide

3   testimony regarding EPA's implementation of the CAA.

4

5   Q7.   WHAT PATH DID YOUR CAREER TAKE UPON YOUR LEAVING LDEQ?

6   A.   After resigning from LDEQ in 2002, I began working as an environmental consultant

7   with ENVIRON International Corporation. ENVIRON merged with Ramboll effective

8   December 31, 2014, and my consulting career has continued with Ramboll since that

9   time.

10

11   Q8.   WHAT DOES YOUR WORK AS AN ENVIRONMENTAL CONSULTANT ENTAIL?

12   A.   My 15-year consulting practice includes permitting and compliance assistance for all

13   media (air, water and waste) for many types of industrial facilities in several states,

14   including power plants, petroleum refineries, chemical plants, pulp and paper mills, oil

15   and gas production, sulfuric acid and lime plants. I routinely evaluate the applicability of

16   environmental regulations to affected facilities and the specific compliance obligations

17   those facilities must meet. I have led several multi-media compliance audits, assisting

18   facilities in identifying and resolving compliance issues. I evaluate the potential for air

19   quality impacts resulting from existing and proposed facility operations and develop

20   emission control strategies and compliance assurance monitoring plans. I have worked

21   with a number of facilities to self-disclose noncompliance to LDEQ, respond to LDEQ

1   notices of violation, compliance orders and potential penalties, and to reach settlement

2   agreements.

3   In addition to my work with industrial clients, my practice includes working with

4   business and commerce groups, and with local and state governments. For example, I

5   have provided consulting services to the American Chemistry Council. I have provided

6   environmental consulting services to the City of Baton Rouge/Parish of East Baton

7   Rouge Office of the Mayor, the Baton Rouge Chamber of Commerce, the State of

8   Louisiana, and the National Association of Clean Air Agencies.

9

10 Q9.   DO YOU CURRENTLY SPECIALIZE IN AIR PERMITTING MATTERS?

11 A.   Yes. My work involves environmental permitting and compliance matters under air,

12   water, and waste programs, as well as wetlands and various other environmental

13   programs; however, a significant portion of my work is in air quality. In my consulting

14   practice, I have assisted multiple facilities in identifying, reporting and resolving

15   retrospective CAA PSD compliance issues. I have performed numerous project reviews

16   on behalf of clients to determine whether the proposed changes would constitute a minor

17   or a major modification under the PSD program, and I have developed the appropriate

18   permit applications. On behalf of my clients, I have obtained both PSD and minor

19   modification permits for proposed modifications to their facilities. I have performed

20   MACT applicability and compliance assessments. I have evaluated toxic air pollutant air

21   quality impacts resulting from facility operations and developed compliance assurance

22   monitoring plans.

1   Q10.   ARE YOU CURRENTLY WORKING ON OTHER TYPES OF ENVIRONMENTAL

2   PERMITTING PROJECTS?

3   A.   Yes, my recent and current work includes numerous projects to support environmental

4   permitting and compliance for large-scale greenfield industrial developments in

5   Louisiana. Those projects typically involve developing applications for several

6   environmental permits in addition to air permits, including construction stormwater

7   permits, water discharge permits, wetlands permits, and permits to authorize the

8   construction of ship and barge docks and cooling water intake structures.

9

10   Q11.   PLEASE DESCRIBE ANY PROFESSIONAL AFFILIATIONS AND THE TYPES OF

11   PUBLICATIONS AND PRESENTATIONS YOU HAVE AUTHORED.

12   A.   My professional affiliations include serving on the Board of Directors of the Louisiana

13   Section of the Air and Waste Management Association for more than ten years beginning

14   in 1995, including multiple terms as Director, a two-year term as Vice Chair (2003 –

15   2004), a two-year term as Chair (2005- 2006), and a two-year term as Past Chair (2007 –

16   2008). For the State and Territorial Air Pollution Program Administrators, I served as

17   Chair of the Air Toxics Committee from 1996 to 2002 and as Vice President in 2001 and

18   2002. My role as Air Toxics Committee Chair involved serving as a liaison between EPA

19   and the State Air Directors, including compiling and preparing comments on behalf of

20   State Air Directors across the country on EPA rulemakings for MACT standards and other

21   Clean Air Act regulations.

1   As for publications, my career has been focused on the development, writing and

2   promulgation of air quality regulations to implement state and federal air quality statutes.

3   Over the course of my career I have been a frequent speaker for many groups and events,

4   including the American Bar Association, the American Chemistry Council, the

5   International Air and Waste Management Association, the Society of Women Engineers,

6   the Clean Air Information Network, the Massachusetts Institute of Technology

7   Symposium on Air Toxics, the Environmental Protection Agency, and the National

8   Association of Clean Air Agencies (formerly State and Territorial Air Pollution Program

9   Administrators).   My presentations have included regulatory training, policy,

10   environmental quality trends and developments, and other topics related to state and

11   federal environmental program development and implementation. I frequently develop

12   and present training materials for clients on state and federal permitting requirements,

13   CAA compliance and enforcement topics.

14

15 Q12. HAVE YOU PREVIOUSLY BEEN QUALIFIED AS AN EXPERT WITNESS AT

16   TRIAL, PROVIDED EXPERT WITNESS TESTIMONY, OR PROVIDED

17   DEPOSITIONS OR AFFIDAVITS IN MATTERS RELATED TO ENVIRONMENTAL

18   REGULATIONS AND PERMITTING REQUIREMENTS?

19 A.   Yes.   While serving at LDEQ, I provided testimony on numerous occasions to the

20   Louisiana legislature, as well as sworn testimony before the U.S. Congress, and I was

21   called upon to provide sworn deposition testimony in several environmental litigation

22   matters in relation to my role as an environmental regulator.

1   Since leaving LDEQ, I have been qualified as an expert on environmental

2   regulatory matters and provided testimony in several permit appeal cases and litigation

3   matters. Specifically, I have served on the following cases: Expert report testimony and

4   expert witness trial testimony on behalf of Trus Joist McMillan in Case No. 70,287B, *Joe*

5   *Clark v. Trus Joist McMillan, et al. and Michael Wolff*, 10th Judicial District Court,

6   Natchitoches Parish, Louisiana, in 2004; Expert witness support and affidavit testimony

7   on behalf of the City of Baton Rouge in Case No. 04-60408, *City of Baton Rouge v. EPA*,

8   5th Circuit Court of Appeal, and in support of the Baton Rouge Area Chamber in *Baton*

9   *Rouge Area Chamber v. EPA*, D.C. Circuit Court of Appeal, 2004; Expert reports in the

10   matter of *Californians for Alternatives to Toxics, et al. v. Evergreen Pulp, Inc.*, 2006;

11   Expert opinion affidavit testimony on behalf of Cabot Corporation in the matter of *Cabot*

12   *Corporation v. Private Power LLC, et al.*, Civil Action No. 02-5324-BLS2, Common

13   Wealth of Massachusetts Trial Court, Superior Court, 2008; Expert reports and affidavit

14   in *Arabie, et al., v. Citgo Petroleum* and *Kitts, et al., v. Citgo Petroleum*, 2008 and 2009;

15   Expert opinion report and affidavit testimony in *State of Ohio v. Certainteed*, 2008 and

16   2009;   Expert report and testimony at hearing in the matter of *Sierra Club and*

17   *Hempstead County Hunt Club v. Arkansas DEQ and Southwestern Electric Power*

18   *Company Turk Power Plant*, 2008 and 2009;   Expert report, deposition and trial

19   testimony in *Willie Buard, et al. vs. Colfax Treating Company, LLC, et al.*, 2009 and

20   2010;   Expert declaration testimony in *American Chemistry Council v. U.S.*

21   *Environmental Protection Agency*, Case No. 10-1167, 2010; Expert affidavit and

22   deposition testimony in *Natural Resources Defense Council, Inc., et al. v. Chris Korleski,*

1   *Director, Ohio EPA and Ohio River Clean Fuels*, 2010 and 2011; Expert declaration

2   testimony in *National Association of Manufacturers, et al. v. EPA*, four consolidated

3   petitions for review in the D.C. Circuit Court of Appeals, 2010; Expert report and

4   deposition in *Chedotal, et al. v. Kinder Morgan Energy Partners, LP, et al. and*

5   *International Marine Terminals*, 2010 and 2011; Expert report and deposition testimony

6   in *Patrick Baughn and Anna Marie Baughn v. BP Exploration Inc., et al.*, 25th JDC,

7   State of Louisiana, 2011; Expert report on behalf of Roy O. Martin Company,

8   Alexandria, Louisiana, in the matter of *Paige, et al. v. Durawood Treating Company,*

9   *LLC, et al.*, regarding the claims of Cathy General, 2011 and 2012; Expert report and

10   deposition testimony in *Kevin LeMaire v. Cooper/T. Smith Stevedoring Company, Inc.*,

11   23rd JDC, State of Louisiana, 2012; and Expert report in *Louisiana Environmental Action*

12   *Network and Stephanie Anthony v. Exxon Mobil Corp. d/b/a ExxonMobil Chemical Co.*,

13   U.S. District Court, Middle District of Louisiana, 2017.

14

15   **II.   PURPOSE OF TESTIMONY**

16   Q13.   ON WHOSE BEHALF ARE YOU PROVIDING THIS DIRECT TESTIMONY?

17   A.   I am testifying on behalf of Entergy New Orleans, Inc. ("ENO"), in relation to ENO's

18   Supplemental and Amending Application ("Supplemental Application") for the proposed

19   New Orleans Power Station ("NOPS").

1   Q14. PLEASE BRIEFLY DESCRIBE THE TWO ALTERNATIVES PRESENTED IN

2   ENO'S SUPPLEMENTAL APPLICATION.

3   A.   The first alternative, which was presented in the Application previously filed with the

4   Council of the City of New Orleans ("CNO" or "Council") on June 20, 2016, is the 226

5   megawatt[1] ("MW") natural-gas-fired combustion turbine ("CT") project. This option is

6   composed of a single natural-gas fired turbine generator with associated ancillary

7   equipment.

8   The second alternative included in ENO's Supplemental Application is the 128

9   MW natural-gas-fired reciprocating internal combustion engines ("RICE") project. This

10   option is composed of seven 18 MW natural gas-fired reciprocating internal combustion

11   engines ("RICE") with associated ancillary equipment.

12

13   Q15. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

14   A.   The purpose of my testimony is: 1) to provide an overview of the environmental permits

15   required for the proposed NOPS; 2) to provide information about the air permitting

16   process and air quality review as required by the New Source Review and Title V air

17   permitting programs, including the process for considering proposed emissions increases

18   and contemporaneous emissions decreases; 3) to provide an overview of the types of

---

[1]   The maximum output of the CT is dependent on ambient conditions (*e.g.*, temperature, humidity, elevation, etc.) In summer conditions, the maximum output of the CT is approximately 226 MW. Under ISO conditions (*i.e.*, standardized conditions established for this technology by the International Organization for Standardization), maximum output is approximately 246 MW.

1   regulated air pollutants considered in the permitting process; and 4) to provide

2   information about the National Ambient Air Quality Standards ("NAAQS") for criteria

3   pollutants, including EPA's process for establishing the NAAQS and how states

4   implement the NAAQS and consider them in the air permitting process. I will also

5   address some specific concerns raised by certain intervenors, and in particular by Dr.

6   George Thurston in his Direct Testimony submitted on behalf of the Alliance for

7   Affordable Energy, the Deep South Center for Environmental Justice, and the Sierra

8   Club, with regard to $PM_{2.5}$ emissions from the proposed NOPS in relation to the NAAQS

9   and air permitting.

10

11   **III. NOPS-REQUIRED ENVIRONMENTAL PERMITS**

12   **A.   Overview of Required Environmental Permits**

13 Q16. HOW DO THE TWO ALTERNATIVE PROJECTS COMPARE FROM THE

14   PERSPECTIVE OF ENVIRONMENTAL PERMITTING?

15 A.   While some of the specific standards and permit terms would differ, in general the two

16   alternatives require the same environmental permits. For either option, the environmental

17   permits ENO would be required to obtain include the following:

18   1) Air Permits: Under the requirements of the federal Clean Air Act, a Title I
19   preconstruction permit is required to authorize construction, and a modification to
20   the existing Michoud Plant Title V operating permit is required for operation of
21   the NOPS. The LDEQ air permitting procedures combine these preconstruction
22   and operating permitting programs under a single permit application, review and
23   issuance process, which ENO must complete prior to commencement of
24   construction. That is, prior to construction of the facility LDEQ performs the
25   preconstruction review and the review of all state and federal air quality
26   requirements that will apply to operation of the facility.

1   2) Construction Stormwater Permit: For either alternative, the discharge of
2   stormwater from the construction site will be regulated under LDEQ's
3   Construction Stormwater General Permit. ENO must submit a Notification of
4   Intent to obtain coverage under the General Permit prior to disturbance of land at
5   the construction site. For either alternative, ENO must develop and implement a
6   Stormwater Pollution Prevention Plan (SWPPP) to minimize the discharge of
7   pollutants in stormwater effluent from the construction site.

8   3) Water Discharge Permits: Under the requirements of the federal Clean Water Act,
9   ENO must obtain a modification to the facility's Louisiana Pollutant Discharge
10   Elimination System ("LPDES") permit for either alternative, which will regulate
11   the level of pollutants contained in wastewater and stormwater discharges from
12   the facility. The LPDES permit will also require the implementation of a SWPPP
13   for the operating phase of the project, for either alternative.

14   In addition to the LPDES permit, for either alternative ENO must comply with
15   City of New Orleans ordinances and permit requirements for stormwater
16   management to reduce urban runoff, diminish subsidence, and encourage
17   sustainable development.

18   4) Coastal Use Permit: Because the project is located in the Louisiana Coastal Zone,
19   for either alternative ENO must obtain a Coastal Use Permit ("CUP") from
20   Louisiana Department of Natural Resources ("LDNR"), or a determination that
21   the project would not require a CUP, prior to the disturbance of land at the project
22   site.

23   5) Section 404 Wetlands/Waters of the U.S. Permit: ENO is working with LDNR
24   and the United States Army Corps of Engineers ("USACE") to identify the
25   required permitting actions for NOPS construction, and will obtain any required
26   permits to address potential impacts to wetlands or other jurisdictional waters of
27   the U.S.

28

29   **B.   Overview of NOPS Air Quality Permitting**

30 Q17. SPECIFICALLY WITH REGARD TO AIR EMISSIONS, HOW DO THE TWO

31   ALTERNATIVES COMPARE?

32 A.   Either alternative would result in substantial decreases in permitted (allowable) emissions

33   for the NOPS as compared to the currently permitted Michoud Power Plant. The tables

1   below present the "Before" and "After" permitted emissions for each alternative, based

2   on currently available project information.

3   **Table 1**
4   **Comparison of "Before" and "After" Permitted Emission Rates**
5   **NOPS Alternative 1, 226 MW CT Project**
6

Pollutant	"Before" Currently Permitted Michoud Power Plant Emissions (tons per year)	"After" Anticipated Permitted NOPS Emissions[2] 226 MW CT Project (tons per year)	Change in Permitted Emissions (tons per year)	Percent Reduction (%)
PM$_{10}$	283.55	13.82	-269.73	95.1%
PM$_{2.5}$	283.55	13.82	-269.73	95.1%
SO$_2$	22.55	7.26	-15.79	67.8%
NO$_x$	8,596.89	273.12	-8,323.77	96.8%
CO	3,132.53	657.04	-2,475.49	79.0%
VOC	205.35	102.82	-102.53	49.9%

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2   Based on LDEQ proposed Permit No. 2140-00014-V5, Activity No. PER20160002, EDMS Document No. 10454574, retrieved June 20, 2017. Proposed permitted emissions are subject to change based on updated project information or subsequent LDEQ review.

1

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

Pollutant	"Before" Currently Permitted Michoud Power Plant Emissions (tons per year)	"After" Anticipated Permitted NOPS Emissions[3] 128 MW RICE Project (tons per year)	Change in Permitted Emissions (tons per year)	Percent Reduction
PM_{10}	283.55	97.61	-185.94	65.6%
$PM_{2.5}$	283.55	97.61	-185.94	65.6%
SO_2	22.55	2.87	-19.68	87.3%
NO_x	8,596.89	50.39	-8,546.50	99.4%
CO	3,132.53	89.31	-3,043.22	97.1%
VOC	205.35	105.38	-99.97	48.7%

6

7   Q18.   BASED ON YOUR CURRENT KNOWLEDGE OF THE TWO ALTERNATIVES, DO

8   YOU EXPECT THE TYPE OF AIR QUALITY REVIEW OR THE AIR PERMITTING

9   PROCESS TO DIFFER?

10   A.   No, I expect both alternatives to require the same level of air quality review and the same

11   type of air quality permit, and to undergo the same air permitting procedures. In fact,

12   ENO is preparing an air permit application that will present both alternatives for LDEQ

13   review and approval, so that either alternative can be constructed consistent with CNO's

14   decision.

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3   Based on preliminary emissions calculations provided by ENO June 2017. Emissions estimates are subject to change based on updated project information or LDEQ review.

1   Q19.   PLEASE SUMMARIZE THE AIR PERMITTING PROCESS THAT WILL APPLY

2   FOR NOPS, BASED ON THE PROJECT INFORMATION AVAILABLE TO YOU AT

3   THIS TIME.

4   A.   First, with regard to the preconstruction review program, either alternative would be

5   considered a "minor modification" under the PSD program, with substantial net emission

6   decreases of some pollutants and net emissions increases below EPA-established

7   significance thresholds for all pollutants. As discussed further below, the net emissions

8   change is based on a comparison of the *proposed permitted emissions* for the project to

9   the *actual emissions* that occurred from the Michoud Units 1, 2, and 3, which are now

10   retired.[4] Because actual emissions for a unit are typically much lower than its permitted

11   emissions, this comparison is not an "apples to apples" analysis. Rather, it is very

12   conservative and can result in a projection of net emission increases even for cases where

13   the actual change in emissions is expected to be a decrease. Because the NOPS project is

14   expected to be a minor modification under the preconstruction review program based on

15   this conservative analysis of emission changes, a major modification PSD permit would

16   not be required for either alternative.

17   With regard to the Title V operating permit program, the required air permit for

18   either alternative would be issued as a modification to the existing Michoud Plant Title V

19   permit. As I previously stated, ENO will submit an air permit application to the LDEQ to

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[4]   Michoud Unit 1 has not been operated to generate electric power for several years, but has continued to be
operated as a steam generating boiler to support startup of Unit 3 until January 2016.

1   provide the information required for both the preconstruction review and the operating

2   permits review. An application addressing each alternative will be submitted, either

3   combined or concurrently. LDEQ will review the application submittal to assure no

4   adverse air quality impacts would result from the project, and to identify all applicable

5   state and federal regulations and standards for the proposed equipment. When the

6   permitting review procedures are complete, including any associated public or EPA

7   review and comment periods on the draft permit and application materials, LDEQ would

8   take final action on the Title V permit modification request. A final permit to modify the

9   Title V permit would also include LDEQ authorization to construct the NOPS.

10

11   **IV.   THE PSD PROGRAM AND MAJOR VS. MINOR MODIFICATIONS**

12   **A.   Brief Overview of the PSD Program**

13   Q20. YOU INDICATED THAT EITHER ALTERNATIVE FOR THE NOPS PROJECT

14   WOULD BE CONSIDERED A MINOR MODIFICATION UNDER THE PSD

15   PROGRAM. CAN YOU BRIEFLY EXPLAIN WHAT THE PSD PROGRAM IS?

16   A.   Yes. First, under the federal CAA, EPA sets the NAAQS for pollutants of concern, and

17   each state is required to implement a plan for attaining and maintaining compliance with

18   the NAAQS for all regions of the state. The CAA also establishes a preconstruction

19   permitting program, called New Source Review, by which state permitting authorities

20   review proposed new stationary sources and proposed modifications to existing stationary

21   sources prior to commencement of construction, to assist in meeting the NAAQS and

22   protecting air quality. New Source Review is composed of two separate but related

1   programs – one that applies if the area where the project would be located has not yet

2   attained air quality that meets the NAAQS (called "nonattainment areas"), and one that

3   applies if the area where the project would be located is in attainment with the NAAQS

4   (called "attainment areas"). The same project can be subject to both programs for

5   different pollutants, if the area has a different attainment status for different NAAQS.

6   Orleans Parish is in attainment with all of the NAAQS, meaning the air quality in the

7   parish meets all federal air quality standards. Therefore, only the New Source Review

8   program for attainment areas applies here.

9   The PSD program is the New Source Review preconstruction permitting program

10   designed to help states maintain compliance with these federal air quality standards in

11   attainment areas. As the name implies, the PSD program is intended to prevent any

12   significant deterioration of air quality in those areas. To accomplish this goal, the PSD

13   program requires permit applicants for any *new major stationary source* or any *major*

14   *modification* to an existing major stationary source to undergo a control technology

15   review and to conduct an air quality analysis to demonstrate that the proposed emissions

16   would not cause or contribute to an exceedance of the NAAQS and would not cause an

17   exceedance of allowable pollution increases, called PSD increments, for the area.

18

1   **B.   Major and Minor Modifications**

2   Q21.   WHAT IS A MINOR MODIFICATION UNDER THE PSD PROGRAM, AND HOW IS

3   THE NOPS PROJECT DETERMINED TO BE A MINOR MODIFICATION?

4   A.   In brief, each proposed project to modify an existing facility (that is, any physical change

5   or change in the method of operation at an existing stationary source) is classified as

6   either a minor modification or major modification based on the level of the emissions

7   change that will result from the project for PSD-regulated pollutants. A project is a major

8   modification if two criteria are met:

9   1)   A significant emissions increase will result from the project; and,

10   2)   A significant net emissions increase will result from the proposed project
11   considered together with any other creditable emissions increases and decreases
12   occurring during the contemporaneous time period.

13   Any modification project that does not meet these two criteria is classified as a *minor*

14   *modification* because the emissions changes associated with the project have been

15   determined by EPA to be *de minimis* with regard to their potential for adversely

16   impacting air quality. [5]

17   The procedures for calculating the emissions increase from the project and the net

18   emissions increase over the contemporaneous time period can be complex, but are

19   designed to assure the protection of air quality in attainment areas such as Orleans Parish.

20   Each PSD-regulated pollutant is reviewed separately, and EPA has established pollutant-

21   specific significant emissions rates, also referred to as *de minimis* emission rates, which

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[5]   *Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers
(PM$_{2.5}$)*, EPA, Final Rule, 73 FR 28,332, May 16, 2008.

1   are based on the environmental and health effects of the pollutant and the corresponding

2   NAAQS. If the project emissions increase and/or the net emissions increase resulting

3   from a proposed modification are less than the pollutant-specific significant emission rate

4   for all PSD-regulated pollutants, then EPA considers the emissions change to be *de*

5   *minimis* and the modification is classified as minor. If a significant project emissions

6   increase and a significant net emissions increase would occur for one or more PSD-

7   regulated pollutant(s), then the project is a major modification and must undergo PSD

8   review with respect to the particular pollutant(s) for which a significant increase would

9   occur.

10   The PSD significant emissions rates for the PSD-regulated pollutants of interest

11   are shown in Table 3 for reference.

12   **Table 3**
13   **PSD Significant Emission Rates for Selected PSD Pollutants**
14

Pollutant	PSD Significant Emission Increase Level (tons per year)
PM_{10}	15
$PM_{2.5}$	10
SO_2	40
NO_x	40
CO	100
VOC	40

15

1   Q22.   UNDER THE FIRST PART OF THE DETERMINATION OF WHETHER A

2   PROPOSED CHANGE IS A MAJOR OR MINOR MODIFICATION, HOW IS THE

3   PROJECT EMISSIONS INCREASE DETERMINED?

4   A.   For projects such as NOPS, which proposes to install only new emissions units, the

5   project emissions increase for each pollutant is the sum of the proposed permitted

6   emission rates for that pollutant, from all emissions units that will emit that pollutant.

7   Thus, the project emissions increase is based on the maximum potential emissions that

8   could occur in any given year, assuming every proposed emissions unit emits the

9   pollutant at the full annually permitted rate. This is a very conservative estimate of the

10   emissions increases that would actually occur from the project. Furthermore, this first

11   step in the process does not consider any emissions reductions that would also occur as a

12   result of or during the same time period as the project. Only proposed emission increases

13   are considered at this stage.

14   For the NOPS 226 MW CT and the 128 MW RICE alternatives, the project

15   emissions increases are represented by the "After" Anticipated Permitted Emissions listed

16   in Table 1 and Table 2, respectively.

17

18   Q23.   UNDER THE SECOND STEP OF THE DETERMINATION OF WHETHER A

19   PROJECT IS A MAJOR MODIFICATION, HOW IS THE NET EMISSIONS

20   INCREASE DETERMINED?

21   A.   Under this step, the permit applicant and the permitting authority consider any other

22   creditable increases or decreases in emissions that have occurred or will occur within the

1   contemporaneous period for the proposed project. The net emissions change associated

2   with the proposed project is the sum of all of the increases and decreases for the

3   particular pollutant over the contemporaneous time period of the project. This procedure

4   is commonly referred to as "netting." Again, the procedures for calculating the level of

5   emissions increases or decreases are conservative, meaning that they are intended to

6   avoid any underestimation of an emissions increase and to avoid any overestimation of an

7   emissions decrease.

8   The contemporaneous period is defined as the time period beginning five years

9   before the projected commencement of construction on the proposed project, and ending

10   on the date that the increase in emissions from the proposed project will occur. For the

11   NOPS project, the contemporaneous period would be approximately January 2013 to

12   October 2019.[6]

13   To be considered a creditable decrease in emissions, several factors must be met.

14   For example, the emission reduction must be permanent and enforceable. Also, an

15   applicant cannot get "credit" simply for reducing permitted emissions; only reductions in

16   actual emissions are creditable. Also, any actual emissions that were above permitted

17   emission levels or other applicable emission standards are not creditable, but must be

18   excluded from the determination.

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[6]   Based on anticipated commencement of construction in January 2018, and anticipated commencement of
operation in October 2019.

1   For the recently retired Michoud Units 1, 2, and 3, creditable emission reductions

2   are determined by calculating the level of actual emissions that occurred from each unit

3   representative of normal operation during the defined baseline period. The calculations

4   are based on actual monitoring or test data or EPA-approved emission factors together

5   with the actual operating data of the units. Based on my understanding of the project

6   information, the Michoud Unit 1, 2, and 3 shutdowns are the only contemporaneous

7   emission changes in the netting window.

8   In summary, construction of the proposed NOPS is a minor modification under

9   the PSD program because, for every PSD-regulated pollutant that would be emitted from

10   the new units, the proposed permitted emission rate and/or the contemporaneous actual

11   net emissions change is less than that pollutant's PSD significant emission rate as shown

12   in Table 3. Based on this determination, the project would not be expected to adversely

13   impact air quality with regard to the NAAQS.

14

15   **C.   Air Permitting Review of Minor Modifications**

16   Q24.   WHY ISN'T PSD REVIEW REQUIRED FOR A MINOR MODIFICATION?

17   A.   To reiterate, PSD review is not required for a minor modification such as the proposed

18   NOPS because any contemporaneous emissions increase that would result from a minor

19   modification is less than the pollutant-specific significant emission rate. Such an increase

20   is considered *de minimis* and therefore would not be expected to cause or contribute to an

21   exceedance of the NAAQS or to have an adverse impact on the air quality of the area.

1   In establishing the significant emission rates, EPA identified a level of emission

2   increase that would be unlikely to cause ambient impacts above the significant impact

3   level for the NAAQS. For example, the original significant emission rate for particulate

4   matter (25 tons per year) was set by EPA using an air quality modeling analysis to

5   determine the level of emissions that would be unlikely to cause ambient impacts above 4

6   percent of the PM NAAQS.[7] The NAAQS itself is set at a level protective of public

7   health and the environment, and the potential impacts from a minor modification would

8   be at levels that are only a very small fraction of the NAAQS.

9

10   Q25.   NONETHELESS, DOES LDEQ REVIEW MINOR MODIFICATIONS TO ASSURE

11   AIR QUALITY IS PROTECTED?

12   A.   Yes. As an initial matter, LDEQ as the permitting authority is responsible for reviewing

13   the emissions calculations provided by the applicant to assure they are technically sound

14   and correct, and that any emission increases resulting from the modification have been

15   appropriately identified and estimated. Once the emissions estimates have been verified,

16   LDEQ may reasonably conclude emission increases less than the significant emission

17   rate, by definition, would not result in adverse air quality impacts, as that is the

18   fundamental purpose of the significant emission rates as established by EPA – to define

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[7]   73 Fed. Reg. 28,332 – 28,333.

1   the level of emissions that is *de minimis* and therefore unlikely to result in significant

2   impacts to air quality.

3   In addition, LDEQ assesses and incorporates into the draft permit applicable

4   emission control requirements, emission limitations, work practices, monitoring,

5   recordkeeping and reporting requirements based on the type of equipment or activities

6   proposed and the level of potential emissions from the equipment. Despite the *de*

7   *minimis* nature of the emission changes, projects that constitute minor modifications are

8   still subject to numerous air quality emission standards and associated monitoring,

9   recordkeeping and reporting requirements. Also, LDEQ establishes specific allowable

10   mass emission rates for individual emission units or groups of emission units through the

11   permitting process, including both short-term (lb/hr) and annual (ton per year) limits.

12   LDEQ also reviews the application with regard to pollutants not addressed by the

13   NAAQS, including federal hazardous air pollutants and Louisiana toxic air pollutants.

14   Furthermore, LDEQ may choose to perform air dispersion modeling of the

15   proposed emissions to model predicted ambient concentrations resulting from the

16   proposed facility. Also, LDEQ has broad authority under LDEQ air permitting

17   regulations to incorporate into the permit any conditions the agency deems reasonable

18   and necessary to protect air quality.[8]

19

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[8]   *See* LA. Administrative Code (LAC) 33:III.501.C.6.

1   Q26.   WHAT ARE SOME OF THE SPECIFIC AIR QUALITY REGULATIONS AND

2   STANDARDS TO BE ADDRESSED IN THE MINOR MODIFICATION THAT NOPS

3   MUST MEET?

4   A.   Several state and federal regulations and standards will apply to the facility regardless of

5   the alternative selected, including, for example:

6   1) If the 226 MW CT is selected, the equipment must meet New Source Performance
7   Standards ("NSPS") emission limits for CO_2, NO_x, and SO_2, as well as
8   associated monitoring, recordkeeping and reporting requirements;

9   2) If the 128 MW RICE project is selected, the equipment must be certified to meet
10   NSPS emission limits applicable to stationary engines;

11   3) Emergency engines, such as emergency generators or firefighting pump engines,
12   are also subject to federal NSPS emission standards and work practice standards;

13   4) State regulations governing emissions of particulate matter, emissions reporting,
14   housekeeping and maintenance practices, and maintenance of control devices
15   apply to the facility; and

16   5) ENO is subject to requirements for emissions monitoring and reporting, and the
17   payment of annual emissions fees.
18

19   **V. TYPES OF REGULATED AIR POLLUTANTS**

20   Q27.   YOU MENTIONED THAT LDEQ REVIEWS SOME POLLUTANTS THAT ARE

21   NOT ADDRESSED BY THE NAAQS. WHAT ARE THE MAIN CATEGORIES OF

22   AIR POLLUTANTS THAT LDEQ REVIEWS IN THE AIR PERMITTING PROCESS?

23   A.   There are several categories of regulated air pollutants, as described below.[9]

24   1) The "criteria pollutants" are the six pollutants for which EPA has established a

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[9]   *See* LAC 33:III.502 for the regulatory definition of "Regulated Air Pollutant."

1   NAAQS. These are lead ("Pb"); carbon monoxide ("CO"); nitrogen dioxide

2   ("NO$_2$"); sulfur dioxide ("SO$_2$"); particulate matter ("PM"), for which PM$_{10}$ and

3   PM$_{2.5}$ have been established as indicators; and ground-level ozone ("O$_3$"), which

4   is regulated through the ozone precursors nitrogen oxides ("NO$_x$") and volatile

5   organic compounds ("VOC").

6   2) Any pollutant subject to an emission standard under Section 111 of the Clean Air

7   Act (generally, the New Source Performance Standards), is a regulated pollutant.

8   In addition to the criteria pollutants, these include pollutants such as Greenhouse

9   Gases (GHGs), ammonia and hydrogen sulfide.

10   3) Any pollutant subject to an emission standard under Section 112 of the Clean Air

11   Act, which are the National Emission Standards for Hazardous Air Pollutants

12   (HAP). There are currently 187 listed HAP.[10] These include organic compounds,

13   such as benzene and toluene; metals and metal compounds, such as mercury and

14   chromium; and additional compounds such as glycol ethers.

15   4) Any pollutant subject to review under the PSD program, which includes, in

16   addition to the criteria pollutants, Greenhouse Gases ("GHG"), reduced sulfur

17   compounds, sulfuric acid mist, and others;

18   5) Any pollutant listed as a Louisiana Toxic Air Pollutant ("LTAP"), including all

19   federal HAP and numerous other compounds.

20

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[10] *See* https://www.epa.gov/haps/initial-list-hazardous-air-pollutants-modifications

1   **VI. NATIONAL AMBIENT AIR QUALITY STANDARDS ("NAAQS")**

2   **A.   Overview of the NAAQS**

3   Q28.   YOU HAVE DISCUSSED THE NAAQS IN RELATION TO AIR PERMITTING

4   UNDER THE NEW SOURCE REVIEW PROGRAM. WHAT ARE THE NAAQS?

5   A.   The NAAQS are federal air quality standards, expressed as an allowable concentration of

6   pollution in the air, set by EPA to protect public health and the environment. EPA sets

7   two types of NAAQS, *primary* and *secondary*. Primary NAAQS are set to protect public

8   health, including "sensitive" populations such as asthmatics, children, and the elderly.

9   Secondary NAAQS are set to protect public welfare, including visibility, animals, crops,

10   vegetation, and architecture.[11] Each NAAQS includes three components: a pollutant

11   concentration level, an averaging time, and the "form" of the standard, which is the

12   statistical basis or method used to determine whether an area is meeting the standard.

13   Table 4 provides a listing of the current NAAQS.[12]

14

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[11]   *See* https://www.epa.gov/criteria-air-pollutants/naaqs-table

[12]   *See* https://www.epa.gov/criteria-air-pollutants/naaqs-table

1
2
3

Table 4
Current National Ambient Air Quality Standards

Pollutant		Primary/ Secondary	Averaging Time	Level	Form
Carbon Monoxide (CO)		Primary	8 hours	9 ppm	Not to be exceeded more than once per year
			1 hour	35 ppm	
Lead (Pb)		Primary and Secondary	Rolling 3 month average	0.15 $\mu g/m^3$ (1)	Not to be exceeded
Nitrogen Dioxide (NO$_2$)		Primary	1 hour	100 ppb	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
		Primary and Secondary	1 year	53 ppb (2)	Annual Mean
Ozone (O$_3$)		Primary and Secondary	8 hours	0.070 ppm (3)	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years
Particle Pollution (PM)	PM$_{2.5}$	Primary	1 year	12.0 $\mu g/m^3$	Annual mean, averaged over 3 years

Pollutant		Primary/ Secondary	Averaging Time	Level	Form
		Secondary	1 year	15.0 μg/m^3	Annual mean, averaged over 3 years
		Primary and Secondary	24 hours	35 μg/m^3	98th percentile, averaged over 3 years
	PM$_{10}$	Primary and Secondary	24 hours	150 μg/m^3	Not to be exceeded more than once per year on average over 3 years
Sulfur Dioxide (SO$_2$)		Primary	1 hour	75 ppb (4)	99th percentile of 1-hr daily maximum concentrations, averaged over 3 yrs
		Secondary	3 hours	0.5 ppm	Not to be exceeded more than once per year

1   (1) In areas designated nonattainment for the Pb standards prior to the promulgation of the current (2008) standards,
2   and for which implementation plans to attain or maintain the current (2008) standards have not been submitted and
3   approved, the previous standards (1.5 µg/m3 as a calendar quarter average) also remain in effect.

4   (2) The level of the annual NO$_2$ standard is 0.053 ppm. It is shown here in terms of ppb for the purposes of clearer
5   comparison to the 1-hour standard level.

6   (3) Final rule signed October 1, 2015, and effective December 28, 2015. The previous (2008) O3 standards
7   additionally remain in effect in some areas. Revocation of the previous (2008) O$_3$ standards and transitioning to the
8   current (2015) standards will be addressed in the implementation rule for the current standards.

9   (4) The previous SO$_2$ standards (0.14 ppm 24-hour and 0.03 ppm annual) will additionally remain in effect in
10   certain areas: (1) any area for which it is not yet 1 year since the effective date of designation under the current
11   (2010) standards, and (2)any area for which an implementation plan providing for attainment of the current (2010)
12   standard has not been submitted and approved and which is designated nonattainment under the previous SO$_2$
13   standards or is not meeting the requirements of a State Implementation Plan ("SIP") call under the previous SO$_2$
14   standards (40 CFR 50.4(3)). A SIP call is an EPA action requiring a state to resubmit all or part of its SIP to
15   demonstrate attainment of the required NAAQS.

1

2   Q29.   WHAT DO YOU MEAN WHEN YOU SAY EPA SETS THE PRIMARY NAAQS "TO

3   PROTECT PUBLIC HEALTH"?

4   A.   The Clean Air Act directs EPA to set primary NAAQS as necessary to protect the public

5   health with "an adequate margin of safety."[13] In determining the level and form of the

6   standard required, the CAA explicitly states that EPA must assure the standard reflects

7   "the latest scientific knowledge useful in indicating the kind and extent of all identifiable

8   effects on public health or welfare which may be expected from the presence of such

9   pollutant in the ambient air, in varying quantities," including variable factors that may

10   produce an adverse health effect, such as atmospheric conditions and the interaction of

11   the air pollutant with other air pollutants.[14]

12   EPA notes that the CAA requires the agency "to reach a public health policy

13   judgment as to what standards would be requisite – neither more nor less stringent than

14   necessary – to protect public health with an adequate margin of safety, based on scientific

15   evidence and technical assessments that have inherent uncertainties and limitations."[15]

16   EPA further interprets the CAA to require the NAAQS to be set not only to prevent

17   pollution concentrations that have been *demonstrated* to be harmful, but also "to prevent

18   lower concentrations…that may pose an unacceptable risk of harm."[16] That is, EPA

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[13]   42 U.S.C. § 7409.

[14]   42 U.S.C. § 7408.

[15]   78 Fed. Reg. 3097, January 15, 2013.

[16]   *Ibid.*

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1   considers the public health risk associated with exposure to pollution based on the full

2   body of scientific evidence available, and sets the NAAQS at a level that considers the

3   inherent uncertainties of the science and the potential risk of harm suggested by the

4   science, to provide an adequate margin of safety to protect the health of sensitive

5   populations.

6   Once a NAAQS has been established, the CAA also requires EPA to periodically

7   review and revise the NAAQS based on the latest science available. Notably, the cost of

8   achieving the NAAQS is not a consideration of EPA in establishing the NAAQS.

9

10   **B.   Process for Establishing the NAAQS**

11   Q30.   WHAT IS THE PROCESS EPA FOLLOWS TO ESTABLISH THE NAAQS?

12   A.   EPA must undergo notice and comment rulemaking, under the federal Administrative

13   Procedures Act, to adopt a new or revised NAAQS. This process involves extensive

14   public outreach, public comment, and review. Nonetheless, even before beginning the

15   official rulemaking procedures, EPA follows a four-phased approach to develop the

16   proposed NAAQS. Each of these stages also involves significant involvement and input

17   from the public and scientific communities.

18   1) Integrated Review Plan: The first phase is the planning phase, which begins with
19   EPA hosting a science policy workshop to get initial input from the public and
20   scientists.   Based on these discussions and EPA's own considerations, EPA
21   develops an Integrated Review Plan, outlining the review schedule and process,
22   and summarizing the key policy and science issues that will be considered.

1   2) Integrated Science Assessment: EPA performs an extensive and comprehensive

2   review, synthesis and evaluation of the policy-relevant science. EPA integrates

3   the available scientific information in a manner that will provide a framework for

4   assessing public health risks, and documents the review in the Integrated Science

5   Assessment.

6   3) Risk/Exposure Assessment: The next phase builds on the evaluation developed in

7   the Integrated Science Assessment to develop quantitative characterizations of

8   exposures and associated risks to human health and the environment. In the

9   Risk/Exposure Assessment, EPA considers the known or likely effects and risks

10   associated with exposure at recent or current air quality conditions and at

11   conditions meeting the current NAAQS and alternative NAAQS under

12   considerations. EPA also characterizes the uncertainties associated with the

13   exposure and risk estimates.

14   4) Policy Assessment: EPA publishes a Policy Assessment that documents the EPA

15   staff analysis of the scientific basis for alternative NAAQS for consideration by

16   senior EPA management and the Administrator.

17

18   Q31.   WHO PROVIDES INPUT TO EPA'S REVIEW OF THE NAAQS?

19   A.   In general, anyone who chooses to be involved can do so through attending public

20   workshops, meetings and hearings and through providing comment to EPA. EPA's

21   National Center for Environmental Assessment ("NCEA") hosts numerous meetings and

22   workshops specifically for the purpose of bringing together the public and scientific

23   community to discuss issues surrounding public health and the NAAQS.

24   Even at the planning stage in developing the Integrated Review Plan, EPA

25   actively seeks the feedback and input of interested parties and recognized scientific

26   experts. For example, in adopting the current $PM_{2.5}$ NAAQS, EPA consulted with the

1   Clean Air Scientific Advisory Committee ("CASAC") on the draft Integrated Review

2   Plan, and revised the draft to take CASAC comments into account.[17] Also, EPA must

3   consider the input of virtually every scientist who has published peer-reviewed work on

4   the pollutant in question, through the Integrated Science Assessment. For the recent

5     $PM_{2.5}$ NAAQS development, EPA published a draft Integrated Science Assessment in the

6   Federal Register and took comment from the public and from CASAC at a meeting held

7   for that specific purpose. This was followed by publication in the Federal Register of a

8   second draft, and a second meeting of the public and CASAC to provide feedback before

9   a final Integrated Science Assessment was issued.[18] A similar process of public

10   involvement was then undertaken to develop the Risk/Exposure Assessment, followed by

11   a similar process for developing the Policy Assessment. Only after these multiple rounds

12   of public notice and comment, including specific outreach to the scientific community, on

13   each of the four development phases and documents did EPA begin the formal

14   rulemaking process for the current $PM_{2.5}$ NAAQS, with publication of the proposed

15   decision to revise the NAAQS for PM.[19]

---

[17]   78 Fed. Reg. 3093, January 15, 2013.

[18]   78 Fed. Reg. 3094, January 15, 2013.

[19]   77 Fed. Reg. 38890, June 29, 2012.

1   Q32.   WHEN EPA PROMULGATES A FINAL RULE TO ADOPT A NEW OR REVISED

2   NAAQS, IS IT SUBJECT TO CHALLENGES SUCH AS AN ADMINISTRATIVE

3   APPEAL OR COURT ACTION?

4   A.   Absolutely. NAAQS are subject to the same opportunities for challenge and appeal as

5   any other federal rule, and are in fact frequently challenged. It is common for EPA's

6   decision to be challenged both as being overly protective of health, and as being too lax

7   in protecting public health.

8

9   **C.   Process for Implementing the NAAQS**

10 Q33.   ONCE A NAAQS HAS BEEN ESTABLISHED BY EPA, HOW IS IT

11   IMPLEMENTED?

12 A.   Once EPA has set a new or revised NAAQS, it is each state's responsibility to meet the

13   standard in all areas of the state. Each state implements the NAAQS through a State

14   Implementation Plan ("SIP") which is composed of the state laws, regulations, policies,

15   guidelines, and programs necessary to govern air quality and specifically as needed to

16   achieve and maintain compliance with the NAAQS across the state.

17   First, each state must assess the current air quality across the state. This is

18   frequently done on a county-by-county (or parish-by-parish) basis, but some area quality

19   areas are designated as multi-county or multi-parish areas, or based on Metropolitan

20   Statistical Areas (MSAs), particularly where the air quality across a broader area is

21   influenced by the same or similar features or emission sources. Each state makes a

22   recommendation to EPA as to whether, based on available air quality data, each area of

1   the state is in "attainment" or "nonattainment" with the NAAQS, or is "unclassifiable"

2   due to the lack of available data. EPA then reviews and approves or disapproves the

3   state's recommendations for area designations, and ultimately makes official designations

4   of area attainment status across the country.

5   For any area that is designated "nonattainment" the state must develop and

6   implement an attainment plan as part of its SIP, to achieve the NAAQS by a deadline

7   established under federal regulation. The state must demonstrate, for EPA's approval,

8   that the suite of emission reductions, control measures or other elements of the plan will

9   result in attainment of the NAAQS. The attainment demonstration relies upon ambient

10   monitoring networks, airshed modeling, rule effectiveness studies, and other information

11   as prescribed by EPA.

12   In addition, each state must develop and submit for EPA approval an

13   "infrastructure SIP" that provides the state the authority to implement and enforce the

14   necessary framework for attaining and maintaining compliance with the NAAQS. The

15   infrastructure SIP covers both attainment and nonattainment areas, and includes the

16   authority and necessary regulatory provisions for the state to perform New Source

17   Review permitting for proposed minor and major new stationary sources and

18   modifications to existing stationary sources, to assure those projects would not cause or

19   contribute to an exceedance of the NAAQS.

20

1   Q34.   HOW DOES LDEQ DETERMINE WHETHER A PROPOSED PROJECT WOULD

2   CAUSE OR CONTRIBUTE TO AN EXCEEDANCE OF THE NAAQS?

3   A.   As I previously explained, the approach is different depending on whether the location of

4   the project is an attainment or nonattainment area, and depending on whether the project

5   is a minor or major modification.

6   In nonattainment areas, proposed new major sources and proposed major

7   modifications must apply controls that meet the Lowest Achievable Emission Rate

8   ("LAER") and also must obtain creditable emission reductions or "offsets" to offset the

9   proposed emission reductions, thereby assuring the level of emissions to the airshed of

10   the area are not increasing significantly. Because the area is in nonattainment (that is, the

11   air quality exceeds the NAAQS) and because offsets are being provided in the form of

12   emission reduction credits, air quality modeling is not performed for Nonattainment New

13   Source Review permitting. LDEQ oversees the review and "banking" of available

14   emission reduction credits that can be relied upon as offsets, and regulates the use of

15   offsets through the permitting program. New minor sources and minor modifications in

16   nonattainment areas, analogous to minor sources and minor modifications in attainment

17   areas, are considered *de minimis* increases unlikely to adversely impact air quality.

18   Therefore, LAER and offsets are not required.

19   In attainment areas, proposed new major stationary sources and proposed major

20   modifications must apply controls that meet the Best Available Control Technology

21   ("BACT"), and the applicant must perform an air quality analysis to demonstrate the

22   project would not cause or contribute to a NAAQS exceedance or the consumption of the

1   PSD increments. The air quality analysis is multi-tiered, with the first tier composed of

2   conducting an air dispersion model of the proposed emissions increases to assess the

3   potential impact for the project to cause or contribute to an exceedance of the NAAQS.

4   If the model's predicted ambient concentrations in this first tier, called "significance

5   modeling," are below EPA-established Significant Impact Levels ("SIL"), then the model

6   has demonstrated the project would not cause or contribute to an exceedance of the

7   NAAQS and no further review is necessary. The SILs are set at a value that is a small

8   fraction of the corresponding NAAQS, which is considered a *de minimis* impact. If the

9   significance modeling predicts impacts over the SIL, then more refined modeling is

10   required, inclusive of the emissions of other nearby sources.

11   As previously discussed, this type of air quality modeling analysis is not required

12   for minor modifications, because the associated increases (or decreases) are below the

13   significant emission rates and are not anticipated to have the potential for adverse air

14   quality impacts.

15   **VII. THE PM$_{2.5}$ NAAQS**

16   Q35.   INTERVENORS HAVE RAISED CONCERNS ABOUT THE EMISSIONS OF PM$_{2.5}$

17   THAT WOULD RESULT FROM THE PLANT. WHAT IS PM$_{2.5}$?

18   A.   PM$_{2.5}$ is a specific classification of the regulated criteria pollutant, particulate matter

19   (PM). First, PM is categorized for regulatory purposes under the CAA based on the size

20   of the particle, and that is what the numbers represent. PM$_{10}$ is particulate matter that is

21   10 microns or less in diameter. PM$_{2.5}$, also called "fine particulate," is particulate matter

22   that is 2.5 microns or less in diameter. These distinctions are made in recognition of the

1   size of particles that are small enough to enter the airway and therefore affect human

2   health.

3   In addition to distinguishing between size fractions, PM is divided into two

4   distinct components based on its physical state at stack testing conditions: filterable and

5   condensable PM. Filterable PM refers to the fraction of PM emissions that is a solid or a

6   liquid at sampling conditions, and that generally adheres to the filter portion of the

7   sample train. Condensable PM is the fraction of PM that is vapor at sampling conditions,

8   but which will condense into liquid or solid PM once cooled. The extent to which

9   filterable and condensable fractions will correspond to the $PM_{2.5}$, PM_{10}, or larger

10   fractions depends on the test and the sampling equipment being used.   Total PM is the

11   sum of the condensable and filterable components, and includes all fractions. Generally,

12   the smaller size particles are concentrated in the condensable portion of the sample,

13   therefore the condensable portion is often considered to be comprised mostly or wholly

14   of $PM_{2.5}$.

15   Q36.   HAS EPA ESTABLISHED A NAAQS FOR $PM_{2.5}$?

16   A.   Yes, as shown in Table 4, EPA has established multiple NAAQS for PM, including for

17        $PM_{2.5}$. The first $PM_{2.5}$ NAAQS were adopted in 1997, with a revision adopted in 2006.

18   The current $PM_{2.5}$ NAAQS were adopted in 2012. These include an annual primary

1   NAAQS of 12.0 µg/m^3; an annual secondary NAAQS of 15.0 µg/m^3; and, a 24-hour

2   primary and secondary NAAQS of 35 µg/m^3.[20]

3

4   Q37.   ARE THE PM$_{2.5}$ NAAQS DESIGNED TO BE PROTECTIVE OF HUMAN HEALTH?

5   A.   Yes, as I've described, EPA is required to set the primary NAAQS at a level protective of

6   public health, including sensitive populations, with an adequate margin of safety.

7

8   Q38.   YOU'VE DESCRIBED EPA'S PROCESS FOR ESTABLISHING A NAAQS. DID EPA

9   FOLLOW THIS PROCESS TO ADOPT THE 2012 PM$_{2.5}$ NAAQS?

10   A.   Yes.   Overall, the process took approximately five and a half years, and included

11   numerous rounds of public notice and comment and scientific advisory reviews. For the

12   current PM$_{2.5}$ NAAQS, EPA's review process began in June 2007 and extended through

13   December 2012. It included all of the phases previously enumerated, with multiple

14   iterations of draft publications, public meetings and comment periods, and solicitation of

15   views from the CASAC. EPA held at least 11 public meetings and workshops, published

16   15 notices of availability and opportunities for public comment on pre-rulemaking

17   documents, and published four rulemaking notices and notices of public hearings.[21] In

18   addition to the numerous technical documents published in draft and final form, an

---

[20]   78 FR 3085, January 15, 2013.

[21]   https://www3.epa.gov/ttn/naaqs/standards/pm/s_pm_2007_fr.html

1   extensive response to comments document and regulatory impact analysis was published

2   with the final rulemaking to adopt the standards.

3

4   Q39.   WHAT SCIENTIFIC STUDIES AND EVIDENCE DID EPA CONSIDER?

5   A.   In short, EPA considered the full body of peer-reviewed journal articles and studies,

6   including epidemiological studies, and focused on studies relating health effects to $PM_{2.5}$

7   exposure. EPA stated that, in developing the NAAQS, the agency "has drawn upon an

8   integrative synthesis of the entire body of evidence concerning exposure to ambient fine

9   particles and a broad range of health endpoints, focusing on those endpoints for which the

10   Integrated Science Assessment concludes that there is a *causal* or *likely causal*

11   *relationship* with long- or short-term $PM_{2.5}$ exposures. The EPA has also considered

12   health endpoints for which the Integrated Science Assessment concludes there is

13   evidence *suggestive of a causal relationship* with long-term $PM_{2.5}$ exposures."[22]   In

14   adopting the 2012 $PM_{2.5}$ NAAQS, EPA stated, "This intensive evaluation of the scientific

15   evidence and quantitative assessments has provided a comprehensive and adequate basis

16   for regulatory decision making at this time."[23]

---

[22]   78 FR 3097, January 15, 2013.

[23]   *Ibid.*

1   Q40.   WERE THE 2012 PM$_{2.5}$ NAAQS CHALLENGED IN COURT?

2   A.   Yes. Several parties challenged the final NAAQS as adopted by EPA. The challengers

3   asserted that EPA acted unreasonably, under the arbitrary and capricious standard, in

4   amending the level and form of the NAAQS, amending the provisions for ambient

5   monitoring networks, and adopting final revisions to the standards prior to publishing

6   certain implementation documents. The case was argued before the DC Circuit Court of

7   Appeals on February 20, 2014. On May 9, 2014, the Court upheld EPA's decisions and

8   denied the petitions for review on all counts.[24]

9

10   **VIII. CONCERNS RAISED REGARDING PM$_{2.5}$ AND NOPS**

11   **A.   Reliance on the NAAQS to Assure Protection of Public Health**

12   Q41.   IN HIS TESTIMONY ON BEHALF OF THE INTERVENORS, DR. THURSTON

13   TESTIFIES THAT THE PM$_{2.5}$ NAAQS "ARE NOT EFFECTIVE IN PROTECTING

14   THE PUBLIC HEALTH." BASED ON YOUR EXPERT KNOWLEDGE OF THE

15   NAAQS, DO YOU AGREE?

16   A.   No, I do not agree. In my opinion, it is unreasonable to dismiss the NAAQS as

17   ineffective in protecting public health or to disregard the NAAQS in making decisions

18   regarding the approval of the proposed NOPS.

19   Based on my knowledge of the Clean Air Act and of the process EPA adheres to

20   in establishing the NAAQS, including the comprehensive and robust consideration of all

_____

[24]   *See*, *Nat'l Assoc. of Manufacturers v. EPA*, 750 F.3d 921 (D.C. Cir. 2014).

1   relevant scientific studies relating the health effects of exposure to $PM_{2.5}$, I consider it

2   appropriate and reasonable -- indeed, important -- to consider the NAAQS and the well-

3   established framework under New Source Review for evaluating emissions increases and

4   decreases in evaluating proposed power plants and other proposed projects. Dr.

5   Thurston's opinion, which amounts to an assertion that only zero emissions could be

6   considered protective of public health, represents the view of a single scientist. In

7   contrast, the $PM_{2.5}$ NAAQS was developed through an extensive, comprehensive, robust

8   and dynamic process involving the work and input of hundreds of interested individuals

9   and scientists (including Dr. Thurston), the full body of relevant available science, and

10   the careful and deliberate balancing of the risk, exposure, and policy considerations to

11   arrive at a set of standards requisite to protect public health, including sensitive

12   populations, with an adequate margin of safety. Those standards have been subsequently

13   challenged and upheld by the D.C. Circuit Court of Appeals.

14

15   **B.   Consideration of the Michoud Unit Shutdowns**

16 Q42. IN HIS TESTIMONY ON BEHALF OF THE INTERVENORS, DR. THURSTON

17   TESTIFIES THAT BECAUSE THE DEACTIVATED MICHOUD UNITS 1, 2, AND 3

18   WERE SHUT DOWN BEFORE THE NEW NOPS TURBINE WOULD COMMENCE

19   OPERATION, IT WOULD NOT BE REASONABLE TO CONSIDER THEIR

20   EMISSIONS AS PART OF THE "BASELINE." DO YOU AGREE?

21 A.   No, Dr. Thurston is incorrect in his premise that the emissions from the shutdown

22   Michoud units should be ignored, and his testimony is unreasonable if he means to

47

1   suggest that the shutdowns should have been delayed to occur after the startup of the new

2   NOPS unit(s). In fact, the New Source Review regulations require that contemporaneous

3   decreases *must* take place and *must* be permanent and enforceable before, or no later than,

4   the startup of any proposed increases in order for those emission reductions to be

5   creditable in the netting analysis for the contemporaneous period.

6   What is occurring here is precisely consistent with the intent of the regulations.

7   First, ENO shut down and permanently retired the Michoud units.   The resulting

8   reductions are made enforceable by deleting the units from the air permit, such that they

9   are no longer authorized to operate under the CAA. In regulatory terms, a "baseline" of

10   emissions representative of normal operations is established for each of the retired units,

11   in order to determine the level of the emission reductions considered contemporaneous

12   with the proposed NOPS project. Thus, these actual emission reductions, which clearly

13   occurred during the contemporaneous period, are quantified, permanent and enforceable,

14   and can be relied upon in considering the proposed 226 MW CT or the 128 MW RICE

15   project.

16

17   Q43. IS THIS THE SAME "CONTEMPORANEOUS PERIOD" YOU PREVIOUSLY

18   DESCRIBED IN RELATION TO DETERMINING IF A MODIFICATION IS MAJOR

19   OR MINOR UNDER THE PSD PROGRAM?

20   A.   Yes, it is. For the NOPS project, the contemporaneous period is approximately January

21   2013 (five years before commencement of construction) until approximately October

22   2019 (the anticipated date of startup). Since the shutdown of the Michoud units all

1   occurred in 2016, the reductions are clearly within the contemporaneous window and

2   should be considered in determining the net emissions change.

3

4   **C.   Air Quality Modeling of the NOPS Project**

5   Q44.   AS PART OF THE 2016 AIR PERMIT REVIEW FOR THE 226 MW CT, DID LDEQ

6   REQUIRE ENO TO MODEL THE PROPOSED EMISSION INCREASES TO ASSESS

7   THE AIR QUALITY IMPACT OF THE PROJECT?

8   A.   No, LDEQ did not require modeling to be performed, and that is not surprising. The

9   project is a minor modification, with significant reductions of some pollutants and no

10   significant net emissions increases proposed. As previously discussed, it is reasonable for

11   LDEQ to determine that no adverse impacts to air quality will occur based on the level of

12   emission changes, without air quality modeling.

13

14   Q45.   DESPITE THE FACT THAT ENO HAS MADE SIGNIFICANT, PERMANENT

15   EMISSION REDUCTIONS BY RETIRING THE MICHOUD UNITS, AND THAT AIR

16   QUALITY MODELING WAS NOT REQUIRED BY LDEQ FOR AIR PERMITTING,

17   ENO CONTRACTED WITH CK ASSOCIATES TO PERFORM A SCREENING AIR

18   QUALITY MODEL OF POTENTIAL NOPS EMISSIONS IMPACTS. HAVE YOU

19   REVIEWED THE ASSOCIATED MODELING REPORT, AND WHAT ARE YOUR

20   OBSERVATIONS?

21   A.   Yes, I have reviewed the report that was included with Jonathan E. Long's Supplemental

22   Direct Testimony on behalf of ENO in November 2016. Table 3, Screening Model

1   Results, presents model-predicted ambient concentrations from the NOPS emissions

2   sources that are well below the NAAQS for every pollutant modeled. Notably, this

3   model considered only the new emissions proposed for the 226 MW CT and ancillary

4   equipment. It did not take into account the reductions in emissions from the retired

5   Michoud Units 1, 2, and 3. This modelling exercise demonstrates that, even when the

6   substantial emission reductions are not taken into account, the NOPS CT project would

7   not cause an exceedance of the NAAQS.

8

9   Q46. DID ENO PERFORM A SIMILAR MODELLING EXERCISE FOR ALTERNATIVE 2,

10   THE RICE PROJECT?

11   A.   Yes, ENO again contracted with CK Associates to perform a screening model exercise,

12   using the full anticipated permitted emission rates for the RICE project, without taking

13   into consideration the emission reductions associated with the Michoud Unit 1, 2, and 3

14   shutdowns. The model-predicted ambient concentrations from the NOPS emissions

15   sources for Alternative 2 are also well below the NAAQS for every pollutant modeled.

16

17   Q47. DOES DR. THURSTON DISPUTE THE CONCLUSION THAT EMISSIONS FROM

18   NOPS WILL NOT CAUSE THE AIR QUALITY TO EXCEED THE NAAQS OR

19   OTHER REGULATORY STANDARDS?

20   A.   No, Dr. Thurston has not alleged that the NAAQS would be exceeded or that the NOPS

21   emissions would cause any environmental or health-based regulatory standard to be

1   violated. Instead, as noted previously, Dr. Thurston opines that the PM$_{2.5}$ NAAQS "are

2   not effective in protecting the public health."

3

4   Q48.   DR. THURSTON TESTIFIES THAT ENO'S ANALYSIS OF AIR QUALITY

5   IMPACTS IS INADEQUATE BECAUSE ENO DID NOT PERFORM A "HEALTH-

6   RISK ANALYSIS OF PM$_{2.5}$ EMISSIONS FROM THE PROPOSED FACILITY." DO

7   YOU AGREE?

8   A.   No, I do not agree. Dr. Thurston fails to recognize the well-established framework for

9   protection of public health through the establishment and implementation of the NAAQS

10   and the associated New Source Review program. Under the framework for air quality

11   protection in the United States, a uniform standard is applied that is protective of public

12   health. First, EPA establishes the level of ambient concentration that is protective of

13   public health, with an adequate margin of safety (*i.e.,* NAAQS). Second, states

14   continuously monitor the ambient air quality and compare the actual measured

15   concentrations to the NAAQS to assess air quality in relation to the health-based

16   standard. If an area is not attaining the NAAQS, then the state must require reductions in

17   emissions from contributing sources as part of an attainment plan.   Third, when a

18   company such as ENO proposes a project, the projected emissions increases from the

19   project and net emissions change associated with the project is evaluated prior to

20   construction, to assure that air quality and public health are protected.

21   Notably, it is not required, nor would it be appropriate or practical, for individual

22   permit applicants to perform a detailed health-risk analysis of the type described by Dr.

51

1   Thurston as part of the permitting process for every change. This type of analysis is

2   much more suited to a larger scale study covering a broader geographic area and

3   inventory of emissions, such as those conducted by EPA. An individual permit applicant

4   simply could not accomplish the level of robust review that EPA's review and

5   establishment of the NAAQS entails.

6

7   Q49.   DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

8   A.   Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF EAST BATON ROUGE

NOW BEFORE ME, the undersigned authority, personally came and appeared, **BLISS M. HIGGINS,** who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

_____
Bliss M. Higgins

**SWORN TO AND SUBSCRIBED BEFORE ME
THIS 28TH DAY OF JUNE, 2017**

_____
NOTARY PUBLIC

My commission expires: AT DEATH

Kyle B. Beall
BAR ROLL 24957

BEFORE THE

COUNCIL FOR THE CITY OF NEW ORLEANS

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

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

DR. GEORGE LOSONSKY, PH.D., P.G.

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JULY 2017

TABLE OF CONTENTS

EXHIBITS

Exhibit GL-1 Curriculum vitae of Dr. George Losonsky, Ph.D., P.G.

Exhibit GL-2 Addendum to CK Technical Report

Exhibit GL-3 Informational Submittal: *Evaluation of Proposed Groundwater Withdrawals and Subsidence – Entergy New Orleans Power Station*

1   **I.   INTRODUCTION**

2   Q1.   PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

3   A.   My name is George Losonsky, Ph.D., P.G., President of Losonsky & Associates, Inc. of

4   4207 Rhoda Drive, Baton Rouge, Louisiana 70816.

5

6   Q2.   ON WHOSE BEHALF ARE YOU TESTIFYING?

7   A.   I am testifying on behalf of Entergy New Orleans, Inc. ("ENO" or the "Company") in

8   support of the Company's Supplemental and Amending Application for Approval to

9   Construct the New Orleans Power Station ("NOPS") and Request for Cost Recover and

10   Timely Relief ("Supplemental Application").

11

12   Q3.   PLEASE   BRIEFLY   DESCRIBE   YOUR   EDUCATIONAL,   PROFESSIONAL,

13   ACADEMIC, AND BUSINESS EXPERIENCE.

14   A.   I graduated from Munich American High School in Munich, Germany in 1976. I attended

15   Oberlin College in Oberlin, Ohio from 1976 through 1980, where I earned a BA degree

16   in Geology. I attended the University of Cincinnati, where I earned M.S. and Ph.D.

17   degrees in Geology in 1983 and 1992. My areas of study were Physical and Chemical

18   Processes in Geology; Tectonics; Structural Geology; and Sedimentology. At the

19   University of Cincinnati, I worked as a Graduate Assistant and Instructor between 1980

20   and 1986. From 1986 to 1990, I was a Research Associate for the Center Hill Research

21   Lab under contract to the U.S. E.P.A. Risk Reduction Engineering Laboratory in

22   Cincinnati, Ohio. From 1990 to 1991, I was the Chief Hydrogeologist for Midwest Water

23   Resource, Inc. in Charlotte, Michigan. From 1991 to 1992, I was the Manager of

1   Environmental Applications for Baker Hughes, Inc. in Houston, Texas. From 1993 to

2   2002, I was the Technical Project Manager for IT Corporation/IT Group/Shaw

3   Environmental & Infrastructure, in Lake Charles, Louisiana, with assignments in Tampa,

4   Florida; Concord, California; and Kaiserslautern/Ramstein Air Base, Germany. From

5   2002 to 2004, I was a Technical Associate for Geosyntec in Baton Rouge, Louisiana.

6   From 2004 to 2005, I was a Project Manager for CH2M HILL in New Orleans,

7   Louisiana. Since 2005, I have been the President of Losonsky & Associates, Inc. in Baton

8   Rouge, Louisiana. I also served as a Commissioner of the Southeast Louisiana Flood

9   Protection Authority-East from 2007 until 2012.   My Curriculum Vitae ("CV") is

10   attached as Exhibit GL-1.

11

12   Q4.   WHAT ARE YOUR RESPONSIBILITIES AS THE PRESIDENT OF LOSONSKY

13   AND ASSOCIATES, INC.?

14   A.   I manage the company and perform hydrogeological, geochemical, and engineering

15   geology evaluations for environmental, infrastructure, well design, well installation, well

16   testing, and water supply projects.

17

18   Q5.   PLEASE BRIEFLY DESCRIBE YOUR ROLES AND RESPONSIBILITIES AS A

19   COMMISSIONER OF THE SOUTHEAST LOUISIANA FLOOD PROTECTION

20   AUTHORITY – EAST.

21   A.   I attended monthly board meetings, served as Chairman of the Finance Committee,

22   attended various monthly committee meetings on engineering, geotechnical, legal and

23   management topics, attended Association of Levee Boards of Louisiana annual meetings,

4

1   visited and met with the U.S. Army Corps of Engineers ("USACE") to discuss and help

2   coordinate levee and coastal flood protection related projects. My work in board and

3   committee meetings included review, discussion, and recommendations for actions and

4   work performed by the Orleans, Lake Borgne and East Jefferson Levee Districts; the

5   USACE; and the Coastal Protection and Restoration Authority ("CPRA"). The work

6   encompassed the improvements and levee lifting of the southeast Louisiana levee

7   protection system, coastal restoration projects, and Master Plan development for New

8   Orleans area flood protection and coastal restoration.

9

10   Q6.   DID YOU CONTRIBUTE TO THE C-K TECHNICAL REPORT, ATTACHED TO

11   THE SUPPLEMENTAL TESTIMONY OF ENO'S WITNESS, JONATHAN E. LONG,

12   AS EXHIBIT JEL-6?

13   A.   Yes.

14

15   Q7.   PLEASE BREIFLY DESCRIBE YOUR ROLE IN PREPARING THE C-K

16   TECHNICAL REPORT.

17   A.   I wrote, co-wrote, and reviewed sections relating to the operation of groundwater

18   recovery wells at the proposed NOPS site and subsidence related issues. I also developed

19   the Figures relating to subsidence that are depicted in the C-K Techical Report.

20

21   **II.   SUMMARY**

22   Q8.   WHAT IS THE PURPOSE OF YOUR TESTIMONY?

23   A.   The purpose of my testimony is to sponsor, introduce, and briefly discuss the *Addendum*

1   *to the C-K Associates Technical Report of November 16, 2016: Evaluation of Predicted*

2   *Drawdown and Consolidation Settlement Resulting from Proposed NOPS Pumping*

3   ("Addendum to C-K Technical Report" or the "Addendum"), which I attach to my

4   testimony as Exhibit GL-2. My testimony also discusses the *Evaluation of Proposed*

5   *Groundwater Withdrawals and Subsidence – Entergy New Orleans Power Station* report

6   prepared by CB&I Government Solutions, Inc. ("CB&I"), which I attach to my testimony

7   as Exhibit GL-3 (the "CB&I Report").

8   Additionally, my testimony seeks to clarify errors and misrepresentations

9   contained in the Direct Testimony of Dr. Alexander Kolker of January 6, 2017, submitted

10   on behalf of Alliance for Affordable Energy, Deep South Center for Environmental

11   Justice, and Sierra Club.

12

13   Q9.   PLEASE SUMMARIZE YOUR TESTIMONY.

14   A.   In my testimony, I discuss the analyses I performed in preparing the Addendum to the C-

15   K Technical Report. Specifically, I discuss my updated analyses on considerations

16   related to groundwater usage required to operate the Combustion Turbine ("CT") initially

17   proposed in the Application filed on June 20, 2016. I also discuss the analyses of these

18   same considerations that I performed concerning the groundwater usage required for the

19   operation of the seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine

20   ("RICE") Generator sets ("Alternative Peaker") that ENO's Supplemental Application

21   proposes as an alternative to the CT. These supplemental analyses led me to conclude

22   that groundwater withdrawal associated with the Alternative Peaker, like the CT, will not

23   exacerbate subsidence or cause damage to infrastructure in New Orleans East. I also

1   briefly discuss the analyses performed for the initial C-K Technical Report[1] and the

2   conclusions drawn from the initial analyses, which conclusions are consistent with and

3   verified by the Addendum to the C-K Technical Report.

4   With regard to Dr. Kolker's Direct Testimony, I note that his testimony is not

5   based on a valid conceptual model of subsidence and related damage to infrastructure

6   caused by the operation of groundwater extraction wells. His testimony contains incorrect

7   statements about technical concepts related to potential impacts of the proposed operation

8   of NOPS. His testimony contains statements on a variety of topics that are correct in

9   general, but do not have the direct bearing on NOPS or New Orleans East communities

10   that his testimony implies. His testimony also includes statements that misrepresent

11   technical content of the C-K Technical Report to the Council.

12

13   **III.   THE C-K TECHNICAL REPORT**

14   Q10. WHAT DID THE C-K TECHNICAL REPORT CONCLUDE WITH REGARD TO THE

15   EFFECTS OF GROUNDWATER WITHDRAWAL ASSOCIATED WITH THE CT

16   UNIT PROPOSED FOR NOPS?

17   A.   The C-K Technical Report concluded that groundwater withdrawal associated with the

18   CT unit proposed for NOPS will not exacerbate ground subsidence or cause damage to

19   infrastructure in New Orleans East.

20

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[1]   *See* Exhibit JEL-6, "Technical Report – Evaluation of Groundwater Withdrawal and Air Quality," (the "C-K
Technical Report").

1   Q11. WHAT IS THE BASIS FOR THIS CONCLUSION?

2   A. The proposed groundwater withdrawal rate is too small to directly affect subsidence or

3   cause damage to buildings and infrastructure at NOPS or in New Orleans East. This

4   statement is supported by a review of recent testing data for the groundwater wells at the

5   Michoud Facility. As noted in the C-K Technical Report, the specific capacity of the

6   wells located at the proposed NOPS site range from 36.4 to 49.7 gallons per minute

7   ("gpm")/ft. Wells of this capacity range would cause only a minimal drawdown of the

8   water levels in the Gonzales-New Orleans aquifer, which drawdown would be within the

9   range of what one might expect as part of natural variation due to changes in rainfall or

10   river water levels. This minimal drawdown level, coupled with the overall trend of rising

11   water levels in the Gonzales-New Orleans aquifer, which were depicted in Figure 5 in the

12   C-K Technical Report, led me to conclude that the operation of the proposed CT Unit at

13   NOPS (with an anticipated groundwater withdrawal rate of 96 gpm) will not exacerbate

14   subsidence in New Orleans East or cause damage to infrastructure in the area. As I

15   discuss below, the analyses performed for the Addendum also support this conclusion.

16

17   Q12. WHAT DID THE C-K TECHNICAL REPORT CONCLUDE WITH REGARD TO

18   CONCERNS THAT PAST GROUNDWATER USAGE BY THE DEACTIVATED

19   MICHOUD UNITS HAS CAUSED DAMAGE TO INFRASTRUCTURE AND

20   RESIDENCES IN NEW ORLEANS EAST?

21   A. The C-K Technical Report concluded that "groundwater withdrawal at the Michoud Plant

22   is not the cause of observed damage to infrastructure in New Orleans East including

8

1   buildings, roads, and flood protection structures."[2]

2

3   Q13.   WHAT ANALYSIS FORMED THE BASIS OF THIS CONCLUSION?

4   A.   The C-K Technical Report discusses differential settlement of structures, which is an

5   effect that can be caused by subsidence due to consolidation settlement of subsurface

6   sediments. The distinction between the cause and effect is crucial to determining whether

7   groundwater withdrawal can cause damage to infrastructure. Under certain conditions,

8   groundwater withdrawal can contribute to consolidation settlement, which in turn can

9   cause differential settlement that may cause damage to infrastructure such as buildings,

10   roads, and flood protection structures. Consolidation settlement due to groundwater

11   withdrawal occurs in the deep subsurface. Differential settlement observed throughout

12   the New Orleans metropolitan area is caused by localized shallow dewatering due to

13   vegetation, drainage, and other shallow infrastructure. As noted in the C-K Technical

14   Report, groundwater withdrawal from improperly managed wells does have the ability to

15   cause differential settlement. However, where groundwater withdrawal does cause

16   differential settlement, signs of differential settlement (such as damage to buildings and

17   other infrastructure) would be visible at or near the wells themselves.

18   Based on (i) observations made during visits to the NOPS/Michoud site and

19   surrounding areas, (ii) data relating to operation and testing of groundwater wells at the

20   Michoud facility, (iii) area-wide water level and groundwater production data, and (iv)

21   discussions with Company personnel about historical operation and maintenance at the

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2   *See* Exhibit JEL-6 at p. 1.

1   site, I noted the absence of any such signs of differential settlement at the Michoud site.

2   The absence of any evidence of differential settlement at the site of the wells used to

3   provide groundwater for the operation of the deactivated Michoud Units supports my

4   conclusion that any past groundwater pumping at these deactivated Units did not lead to

5   differential settlement or damage to infrastructure, buildings, or flood protection

6   structures located in New Orleans East.

7

8   Q14.   DOES THE C-K TECHNICAL REPORT CONCLUDE THAT THERE HAS BEEN NO

9   SUBSIDENCE IN THE MICHOUD AREA?

10 A.   No, and the statement in Dr. Kolker's testimony concerning this matter misrepresents the

11   substance of the C-K Technical Report to the Council.[3]   In fact, the C-K Technical

12   Report states that "subsidence has occurred in New Orleans East and was caused by

13   multiple factors."[4]   The C-K Technical Report accurately describes the role of isostatic

14   sag in the geologic history of the New Orleans area, along with other processes, in

15   contributing to subsidence.   Dr. Kolker,[5] as well as individuals who have studied

16   subsidence in the New Orleans area, agree that multiple processes cause subsidence. In

17   fact, Ms. Cathleen Jones – the lead author of the 2016 study[6] Dr. Kolker discusses, has

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[3]   *See* Pre-Filed Direct Testimony of Dr. Alexander S. Kolker on Behalf of Alliance for Affordable Energy, Deep South Center for Environmental Justice, and Sierra Club, submitted in this proceeding on January 6, 2017 ("Kolker Testimony"), at p. 3 ("The CK Report [sic] relied upon by Entergy [sic] suggested that there was no subsidence in the Michoud area.").

[4]   *See* Exhibit JEL-6 at p. 2.

[5]   *See* Kolker Testimony at p. 3.

[6]   *See* Jones, C.E., K. An, R.G. Blom, J.D. Kent, E.R. Ivins, and D. Bekaert, 2016, *Anthropogenic and Geologic Influences on Subsidence in the Vicinity of New Orleans, Louisiana*, Journal of Geophysical Research: Solid Earth, doi:10.1002/2015JB012636. This publication has been referred to in local media as the "NASA report" due to the

1   stated that "additional research is needed to directly link groundwater pumping to the

2   subsidence rates," and that, with regard to the Michoud area, it is "unclear whether the

3   subsidence there results from groundwater withdrawal, compaction of soft soils and other

4   soil processes, or because of geologic processes, such as a nearby 'Michoud fault.'"[7]

5   Such additional research was performed for the C-K Technical Report, which led to the

6   conclusion that groundwater withdrawal associated with the deactivated Michoud Units

7   did not contribute "to differential settlement (*i.e.* structural damage) in New Orleans

8   East."[8]

9

10   **IV.   FURTHER ANALYSIS OF SUBSIDENCE ISSUES**

11   Q15. WHAT ADDITIONAL ANALYSES DID YOU PERFORM FOR THE ADDENDUM

12   TO THE C-K TECHNICAL REPORT?

13   A.   I performed drawdown calculations using standard analytical methods used in

14   groundwater hydrogeologic evaluation of aquifer response to the operation of pumping

15   wells. The analytical methods I employed for this purpose are the Theis solution and the

16   Hantush-Jacobs solution. For both solutions, as well as for the settlement calculations I

17   discuss below, I assumed NOPS would operate 24 hours a day, 365 days a year. Although

18   I understand that neither the CT nor the Alternative Peaker is expected to operate at this

19   level of frequency, my assumption was intended to provide the most conservative

20   evaluation possible of groundwater and subsidence related issues for the Council. I also

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affiliation of some of the report authors with the Jet Propulsion Laboratory, which is a NASA-affiliated research
institute associated with the California Institute of Technology.

[7]   *See*, http://www.nola.com/environment/index.ssf/2016/05/new_orleans_area_sinking_assis.html.

[8]   *See* Exhibit JEL-6 at p. 2.

1   performed consolidation settlement calculations using analytical solutions simulating the

2   hydrogeologic setting of the NOPS site, with thick clay overlying the confined New

3   Orleans-Gonzalez aquifer.

4   **A. Drawdown Calculations**

5   Q16.   PLEASE DESCRIBE THE THEIS AND HANTUSH-JACOB SOLUTIONS.

6   A.   The Theis solution is the basic equation for calculating drawdown at different distances

7   away from a groundwater withdrawal well, and it applies known physical characteristics

8   (aquifer parameters) that are specific to the New Orleans-Gonzalez aquifer, including

9   hydraulic conductivity and storage coefficient. The Hantush-Jacob solution is a more

10   complex equation and is more site-specific for NOPS as it accounts for the natural

11   hydraulic communication between the New Orleans-Gonzalez aquifer and overlying clay

12   units.

13

14   Q17.   WHAT IS THE PURPOSE OF PERFORMING A DRAWDOWN CALCULATION

15   WHEN ASSESSING THE EFFECTS OF GROUNDWATER PUMPING?

16   A.   If settlement were to occur as a result of groundwater withdrawal, it would develop in

17   response to drawdown in accordance with the standard drawdown solutions. As such,

18   drawdown calculations help to provide more certainty and accuracy around assessments

19   of possible consolidation settlement associated with groundwater withdrawal.

20

21   Q18.   WHAT FACTORS ARE TAKEN INTO ACCOUNT FOR THE DRAWDOWN

22   CALCULATIONS?

23   A.   Aquifer properties including the hydraulic conductivity of the aquifer, the storage

1   coefficient of the aquifer, its thickness, whether it is confined or unconfined, whether it is

2   leaky or non-leaky, and well specifications including the screen interval and the flow

3   rate.

4

5   Q19. HOW DO THESE DRAWDOWN CALCULATIONS COMPARE TO THE WELL-

6   CAPACITY ANALYSIS YOU DESCRIBED PERFORMING FOR THE C-K

7   TECHNICAL REPORT?

8   A.   The specific capacity measurement is based on short term testing of the well over the

9   course of several hours. It relates to water levels in the well, not in the aquifer at a

10   distance away from the well. As a result, the drawdown calculations performed for the

11   Addendum to the C-K Technical Report represent a more thorough analysis of drawdown

12   potential associated with NOPS.

13

14   Q20. WHAT RESULTS DID THE DRAWDOWN CALCULATIONS YIELD WITH

15   REGARD TO THE CT UNIT?

16   A.   The site-specific calculations (Hantush-Jacob solution) predict a maximum drawdown

17   over a 10-year period[9] of about one foot near the NOPS pumping well, diminishing to

18   half a foot or less at a distance of several thousand feet away, and one quarter foot or less

19   at a distance of two miles from the well. It should be noted that a confined aquifer such as

20   the Gonzales-New Orleans aquifer will reach steady-state drawdown long before 10

21   years, and drawdown will remain essentially unchanged after about 5 years or less.

---

[9]   As discussed in the Addendum to the C-K Technical Report, at p. 2 and 3, a 10-year period is calculated
because it is a conservative (high end) estimate of how long it would take to reach maximum drawdown.

1

2   **Q21.**   WHAT CONCLUSIONS DO YOU DRAW FROM THESE RESULTS CONCERNING

3   THE CT UNIT'S POTENTIAL EFFECTS ON SUBSIDENCE?

4   A.   The CT unit will create insufficient drawdown to exacerbate subsidence.

5

6   **Q22.**   HOW DO THESE CONCLUSIONS COMPARE WITH THE CONCLUSIONS

7   STATED IN THE C-K TECHNICAL REPORT?

8   A.   These conclusions are in agreement with the conclusions of the C-K Technical Report.

9

10   **Q23.**   WHAT RESULTS DID THE DRAWDOWN CALCULATIONS YIELD WITH

11   REGARD TO THE ALTERNATIVE PEAKER?

12   A.   The site-specific calculations (Hantush-Jacob solution) predict a maximum drawdown

13   over a 10-year period of half an inch or less near the NOPS pumping well, diminishing to

14   approximately one hundredth of an inch several thousand feet away from the well. As

15   noted above, this drawdown is expected to remain the same long-term, beyond 10 years.

16

17   **Q24.**   WHAT CONCLUSIONS DO YOU DRAW FROM THESE RESULTS CONCERNING

18   THE ALTERNATIVE PEAKER'S POTENTIAL EFFECTS ON SUBSIDENCE?

19   A.   The Alternative Peaker unit will create insufficient drawdown to exacerbate subsidence.

20

1   **B. Consolidation Settlement Calculation**

2   Q25.   WHAT IS THE PURPOSE OF PERFORMING A CONSOLIDATION SETTLEMENT

3   CALCULATION WHEN ASSESSING THE EFFECTS OF GROUNDWATER

4   PUMPING?

5   A.   The consolidation settlement calculation predicts total possible settlement due to

6   drawdown caused by groundwater pumping. For the analysis presented in the Addendum

7   to the C-K Technical Report, the consolidation settlement calculations predict settlement

8   occurring between 500-650 feet below the surface of the earth.[10]

9   It should also be noted that where groundwater pumping has already occurred at a

10   site, pumping at or below the levels of the previous pumping will not cause additional

11   settlement. In other words, the consolidation settlement calculations presented in the

12   Addendum to the C-K Technical Report do not represent incremental increases to

13   settlement likely to occur at the NOPS site. Rather, they present the calculated total

14   possible consolidation settlement levels associated with the calculated drawdown

15   assuming no prior groundwater pumping has occurred.

16

17   Q26.   WHAT FACTORS ARE TAKEN INTO ACCOUNT WHEN PERFORMING THE

18   CONSOLIDATION SETTLEMENT CALCULATIONS?

19   A.   Consolidation settlement calculations account for soil properties including density, void

20   ratio, and compression index; aquifer properties including thickness, groundwater

21   elevation, and hydraulic conductivity.

---

[10]   *See* Exhibit GL-2 at Table 1.

1

2   Q27.   WHAT RESULTS DID THE CONSOLIDATION SETTLEMENT CALCULATIONS

3   YIELD WITH REGARD TO THE CT UNIT?

4   A.   The calculated total possible consolidation settlement for the CT unit is in the range of

5   0.7 to 4.7 millimeters (0.027 to 0.18 inch) for a flow rate of 96 gpm. (The low end of this

6   range is more likely considering the geological characteristics of the New Orleans-

7   Gonzalez aquifer.) Since a higher flow rate has already been applied to the New Orleans-

8   Gonzalez aquifer in the past, this settlement has already occurred, and continued pumping

9   at the level proposed for operation at the CT unit will not cause additional settlement.

10

11 Q28.   WHAT CONCLUSIONS DO YOU DRAW FROM THESE RESULTS CONCERNING

12   THE CT UNIT'S POTENTIAL EFFECTS ON SUBSIDENCE?

13 A.   The CT unit cannot exacerbate subsidence because the settlement it can create is very

14   small and will already have occurred during past groundwater withdrawal. Once the

15   potential settlement has occurred, pumping at the same or lower flow rates cannot cause

16   additional settlement.

17

18 Q29.   HOW DO THESE CONCLUSIONS COMPARE WITH THE CONCLUSIONS

19   STATED IN THE C-K TECHNICAL REPORT?

20 A.   These conclusions are in agreement with those stated in the C-K Technical Report.

21

1   Q30.   WHAT RESULTS DID THE CONSOLIDATION SETTLEMENT CALCULATIONS

2   YIELD WITH REGARD TO THE ALTERNATIVE PEAKER?

3   A.   The calculated total possible consolidation settlement for the Alternative Peaker is in the

4   range of 0.03 to 0.19 millimeter (0.001 to 0.007 inch) for a flow rate of 3.9 gpm. Since a

5   higher flow rate has already been applied to the New Orleans-Gonzalez aquifer in the

6   past, this settlement has already occurred, and continued pumping at the level proposed

7   for operation of the Alternative Peaker will not cause additional settlement.

8

9   Q31.   WHAT CONCLUSIONS DO YOU DRAW FROM THESE RESULTS CONCERNING

10   THE ALTERNATIVE PEAKER'S POTENTIAL EFFECTS ON SUBSIDENCE?

11 A.   The Alternative Peaker cannot exacerbate subsidence because the settlement it can create

12   is negligible.

13

14   **V.   THE CB&I REPORT**

15 Q32.   YOU MENTIONED A REPORT PREPARED BY CB&I. HAVE YOU REVIEWED

16   THIS REPORT?

17 A.   Yes.

18

19 Q33.   WHAT DOES THE REPORT CONCLUDE?

20 A.   It concludes, based on drawdown calculations and settlement calculations (taking known

21   aquifer characteristics into account), that the proposed NOPS groundwater withdrawals

22   will be too small to contribute to any subsidence in the Michoud area.

23

1   Q34.   HOW DO THE ANALYTICAL METHODS DESCRIBED IN THE CB&I REPORT

2   COMPARE TO THOSE YOU DESCRIBED PERFORMING FOR THE ADDENDUM

3   TO THE CK REPORT?

4   A.   The analytical methods employed for the Addendum and the CB&I Report are founded

5   on the same hydrogeologic and geotechnical principles. The additional analyses that I

6   performed build on the analyses presented in the CB&I Report. The Hantush-Jacob

7   drawdown solution is based on the same Theis solution as the Cooper-Jacob

8   approximation used in the CB&I Report, and in addition it accounts for a leaky aquifer.

9   The Niu-Wang-Chen-Li solution for consolidation settlement is based on the same soil

10   mechanics principles of Karl Terzaghi as the Freeze and Cherry approximation used in

11   the CB&I Report, extended beyond one-dimensional analysis and applied to a

12   groundwater withdrawal well in a confined sandy aquifer, taking into account the

13   overlying clay.

14

15   Q35.   DO THE ANALYSES YOU PERFORMED FOR THE ADDENDUM TO THE C-K

16   REPORT SUPPORT THE CONCLUSIONS DRAWN IN THE CB&I REPORT?

17   A.   Yes.

18

19   Q36.   DO YOU AGREE WITH THE CONCLUSIONS DRAWN IN THE CB&I REPORT?

20   A.   Yes.

21

1   **VI.   DR. KOLKER'S SUBSIDENCE TESTIMONY**

2   Q37. IN HIS DIRECT TESTIMONY, DR. KOLKER IDENTIFIES AS AN AREA OF

3   CONCERN "THE POTENTIAL FOR THE PROPOSED NOPS TO FURTHER

4   CONTRIBUTE TO SUBSIDENCE AT THE NOPS SITE, IN THE SURROUNDING

5   COMMUNITY, AND POTENTIALLY IN NEW ORLEANS' RECENTLY

6   UPGRADED STORM RISK REDUCTION SYSTEM."[11] DO YOU FIND DR.

7   KOLKER'S CONCERN TO BE A LEGITIMATE ONE?

8   A.   No. As noted in the C-K Technical report, my analyses of the groundwater withdrawal

9   associated with the operation of NOPS, as well as of the water levels in the Gonzales

10   New Orleans Aquifer, lead me to conclude that the proposed groundwater withdrawal

11   associated with NOPS will not exacerbate subsidence in New Orleans East. The updated

12   analyses provided in the Addendum to the C-K Technical Report provide further support

13   for these conclusions and indicate that neither the CT nor the Alternative Peaker will

14   exacerbate subsidence or cause damage to infrastructure in New Orleans.

15   In contrast, Dr. Kolker's Direct Testimony does not reflect any analysis of the

16   water levels in the Gonzales-New Orleans aquifer or the specific groundwater

17   withdrawals, drawdown levels, or consolidation calculations associated with the proposed

18   operation of NOPS. It is my professional opinion that, at minimum, an analysis of

19   aquifer water levels and specific well capacities is necessary to substantiate any opinion

20   concerning the possible effects of groundwater withdrawal from a generator. Dr.

21   Kolker's failure to specifically consider these issues with respect to NOPS renders his

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[11]   *See* Pre-Filed Direct Testimony of Dr. Alexander S. Kolker on Behalf of Alliance for Affordable Energy, Deep
South Center for Environmental Justice, and Sierra Club, submitted in this proceeding on January 6, 2017 ("Kolker
Testimony"), at p. 2.

1   testimony baseless.

2

3   Q38. DR. KOLKER'S TESTIMONY DISCUSSES A DIFFERENCE BETWEEN

4   "SUBSIDENCE AND DIFFERENTIAL CONSOLIDATION," AND CONCLUDES

5   THAT "DIFFERENTIAL CONSOLIDATION SHOULD BE THOUGHT OF AS ONE

6   MODE OF SUBSIDENCE, AND NOT DISTINCT FROM IT."[12] DOES DR.

7   KOLKER'S DISCUSSION OF THIS ISSUE REFLECT A CORRECT

8   UNDERSTANDING OF THE CONCEPT OF "DIFFERENTIAL SETTLEMENT,"

9   WHICH THE C-K TECHNICAL REPORT DISCUSSES AT LENGTH?

10   A.   No. Dr. Kolker confuses cause and effect. The C-K Technical Report discusses

11   differential settlement of structures (*i.e.*, the effect), which can be caused by subsidence

12   due to consolidation settlement of subsurface sediments. As I noted above, the

13   distinction between cause and effect is critical to analyzing possible effects of

14   subsidence. Dr. Kolker's confusion about cause in the subsurface and effect at the

15   surface leads him to fail to distinguish between consolidation occurring hundreds of feet

16   deep and consolidation near the ground surface. Consequently, he fails to identify or

17   analyze the actual cause of damage to buildings and infrastructure in New Orleans East

18   and instead points the finger at NOPS and the Deactivated Michoud Units despite having

19   no scientific basis for that conclusion.

20

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[12]   *See* Kolker Testimony at p. 3.

1   Q39.   HOW WOULD YOU RESPOND TO DR. KOLKER'S CONCLUSION THAT "THE

2   DATA PRESENTED BY THE CK REPORT [SIC] ARE WOEFULLY INSUFFICIENT

3   TO JUDGE SUBSIDENCE RISKS"?[13]

4   A.   The data presented in the C-K Technical Report, as detailed above, is sufficient for the

5   conclusions drawn in the Report, and far more substantial than what is presented in Dr.

6   Kolker's testimony. The C-K Technical Report relied on analyses of water level trends

7   and specific capacities of the wells, along with lengthy discussion of the geology and

8   subsidence process, to evaluate subsidence risks. Moreover, the supplemental analyses

9   presented in the Addendum to the C-K Technical Report offer further substantiations for

10   the conclusions drawn in the initial C-K Technical Report concerning the negligible

11   impact of the operation of NOPS on subsidence.

12

13 Q40.   DOES DR. KOLKER'S TESTIMONY CONTAIN ANY DISCUSSION OF ISSUES

14   NOT RELEVANT TO ASSESSING SUBSIDENCE RISKS SPECIFIC TO THE

15   OPERATION OF NOPS?

16 A.   Yes. The references to faulting, peat layers, and sediment loading in the Mississippi

17   birdfoot delta are not directly relevant to the evaluation of potential effects of proposed

18   groundwater withdrawal at NOPS. No significant faulting has been identified that would

19   influence the effects of operating the groundwater wells. Sediment loading in the birdfoot

20   delta in downstream portions of the Mississippi river will not change the effects of

21   operating the groundwater wells. Operating the groundwater wells will not affect peat

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[13]   *Id.*

1   layers near the ground surface.

2

3   Q41.   WHAT DOES THE DISCUSSION OF THESE ISSUES LEAD YOU TO CONCLUDE

4   ABOUT THE ADEQUACY OF DR. KOLKER'S ANALYSIS WITH REGARD TO

5   SUBSIDENCE ISSUES SPECIFICALLY ASSOCIATED WITH NOPS?

6   A.   His discussion of issues not related to the process of groundwater withdrawal and its

7   potential effects on subsidence at NOPS suggests that Dr. Kolker's analysis is unfocused

8   and to a large extent irrelevant.

9

10 Q42.   WERE YOU ABLE TO REVIEW THE CV ATTACHED TO DR. KOKLER'S

11   TESTIMONY AS EXHIBIT 1?

12 A.   Yes.

13

14 Q43.   IS THERE ANYTHING ABOUT DR. KOLKER'S CV THAT YOU BELIEVE THE

15   COUNCIL SHOULD CONSIDER WHEN ASSESSING HIS QUALIFICATION TO

16   PROVIDE OPINION TESTIMONY CONCERNING SUBSIDENCE OR FLOOD

17   RISKS ASSOCIATED WITH NOPS?

18 A.   Yes. Dr. Kolker's background is in surficial coastal processes, but he lacks the

19   background in groundwater wells and subsurface geology to assess the effects of

20   operating NOPS on subsidence or the specific causes of damage to buildings and

21   infrastructure observed in New Orleans East. He also does not seem to have any

22   background specifically related to southeast Louisiana flood protection infrastructure.

23

1   **VII.   FLOOD RISKS**

2   Q44.   YOU MENTIONED SERVING AS A COMMISSIONER ON THE SOUTHEAST

3   LOUISIANA FLOOD PROTECTION AUTHORITY – EAST ("SLFPA-E"); PLEASE

4   DESCRIBE THE PURPOSE AND SCOPE OF YOUR WORK AS A

5   COMMISSIONER.

6   A.   The SLFPA-East was created in response to flooding associated with Hurricane Katrina;

7   its mission was flood protection in the Orleans, Lake Borgne, and East Jefferson Levee

8   Districts. This included protection from flooding due to hurricanes, rain, or other storm

9   surges.   The primary goal of the SLFPA-East was upgrading and maintaining the

10   Hurricane and Storm Damage Risk Reduction System ("HSDRRS"). As commissioner, I

11   reviewed and participated in SLFPA-East's discussions to evaluate plans and proposals of

12   the USACE for the improvement of the New Orleans area levee system with the goal of

13   providing "100 year hurricane flood protection," or 1 percent flood risk. This work

14   involved many engineering and geotechnical issues, including ground elevations,

15   subsidence, modeling predictions of storm surges, surge barriers, canals, and pumping

16   systems. I also reviewed and participated in SLFPA-East's discussions to evaluate the

17   2012 Master Plan developed by the CPRA, which Dr. Kolker references in his testimony.

18   The work also involved assessing the possible effects on sea level rise and climate change

19   of flood risks within the SLFPA-East's jurisdiction.

20

21   Q45.   DO YOU SHARE DR. KOLKER'S CONCERNS REGARDING THE SUPPOSED

22   VULNERABILITY OF THE PROPOSED NOPS SITE TO FLOODING?

23   A.   No. While it is always good practice to be concerned in general, Dr. Kolker's specific

1   concerns do not take into account the risk mitigating effects of the existing HSDRRS or

2   the specific site design proposed for NOPS. In ENO witness Jonathan E. Long's

3   Supplemental Direct Testimony, he describes the specific measures within the HSDRRS

4   that provide added flood protection to the proposed NOPS site. Mr. Long also discusses

5   the process through which the project team determined the appropriate Top of Concrete

6   ("TOC") level for the site and determined that a TOC elevation for NOPS at 3.5 feet

7   above sea level, which is 2.5 feet higher than the Federal Emergency Management

8   Agencey ("FEMA") Advisory recommendation, would adequately mitigate any risks of

9   damage due to flooding at the proposed NOPS site. Dr. Kolker's testimony fails to take

10   these site-specific factors into account and instead provides an analysis that is too general

11   and lacks the specificity to be of real value in determining flood risks at the proposed

12   NOPS site.

13

14   Q46.   DR. KOLKER STATES THAT THE 2012 MASTER PLAN INDICATES THAT THE

15   AREA NEAR NOPS "IS LIKELY TO SEE FLOOD DEPTHS OF 10-15 FEET AT

16   SOME POINT OVER THE NEXT FIFTY YEARS."[14]   DOES THE 2012 MASTER

17   PLAN REPRESENT THE MOST CURRENT EVALUATION OF THIS RISK?

18   A.   No, the 2017 CPRA Master Plan does.[15] Dr. Kolker refers to a flood estimate that was

19   based on flood protection measures as they existed when the 2012 Master Plan was

20   developed, prior to completion of the HSDRRS. As noted in Jonathan E. Long's

---

[14]   *See* Kolker Testimony at p. 7-8.

[15]   *See* http://coastal.la.gov/our-plan/2017-coastal-master-plan/
        I will note that as of the date Dr. Kolker filed his testimony, the 2017 Draft Master Plan represented the most
        current evaluation of the risks Dr. Kolker discussed by referencing the 2012 Master Plan. The CPRA has since
        published the finalized version of the 2017 Master Plan.

1   Supplemental Direct Testimony, the HSDRRS includes a series of levees and storm surge

2   barriers and upgrades to pumping capacity. These upgrades have significantly increased

3   the defense against storm surge in New Orleans East, including at the proposed site of

4   NOPS. The 2017 Master Plan takes these improvements into account and, as a result,

5   predicts no flooding in the same scenario described in Dr. Kolker's testimony. In fact,

6   the flood protection measures that have been installed eliminate estimated flooding (*i.e.,*

7   predicts no flooding) at the proposed NOPS site under the "high scenario" over a 50 year

8   time frame (worst case scenario considered under the Master Plan). This is a significant

9   change compared to the 2012 Master Plan.

10

11   Q47.   TO YOUR KNOWLEDGE, DOES THE DESIGN OF THE MEASURES COMPRISING

12   THE HSDRRS TAKE INTO ACCOUNT ANY INCREASE IN FLOOD RISKS THAT

13   MAY BE ASSOCIATED WITH REGIONAL SUBSIDENCE AND SEA LEVEL RISE?

14   A.   Yes. To my knowledge the USACE and the CRPA are aware of the effects of sea level

15   rise and subsidence and include appropriate safety factors in their planning and design.

16   The CRPA states in the 2012 and 2017 Master Plans that estimates of sea level rise and

17   subsidence are included in the plans.[16] The 2017 Master Plan includes a plan for levee

18   improvements in year 30 of the plan to account for sea level rise and subsidence. As such,

19   the 2017 Master Plan's prediction of no flooding at the NOPS site, even in the "worst

20   case" scenario described above, includes a consideration of regional subsidence and sea

21   level rise.

22

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[16]   *See*, *e.g.*, 2017 Master Plan at p. 72.

1   Q48.   DR. KOLKER RELIES ON THE 2017 DRAFT MASTER PLAN AS SUPPORT FOR

2   HIS STATEMENT THAT "FOR MUCH OF LOUISIANA, FLOOD RISKS ARE

3   LIKELY TO INCREASE IN THE YEARS AHEAD."[17]   IS THIS AN ACCURATE

4   REPRESENTATION OF THE DRAFT MASTER PLAN AND ITS CONCLUSIONS

5   REGARDING THE RISKS OF FLOODING SPECIFICALLY ASSOCIATED WITH

6   THE PROPOSED SITE OF NOPS?

7   A.   No. As noted above, the construction of the HSDRRS has significantly reduced flooding

8   risk at the proposed NOPS site. The design and operation of the HSDRRS has taken into

9   account the projected sea level rise.

10

11   Q49.   DR. KOLKER ALSO CLAIMS THAT A "10-YEAR" RAINFALL "COULD LEAD TO

12   ABOUT ONE FOOT OF FLOODING IN AREAS NEAR THE PROPOSED NOPS

13   PLANT." IS THIS AN ACCURATE ASSESSMENT WITH REGARD TO THE

14   SPECIFIC SITE OF NOPS?

15   A.   No. A storm water management model ("SWMM") was used to estimate existing

16   flooding as well as the efficacy of proposed storage and drainage projects and best

17   management practices proposed throughout the greater New Orleans area. This model

18   was used as a proof of concept for proposed projects. Only low resolution outputs of the

19   model were provided in reports and websites referenced by Dr. Kolker and detailed

20   assumptions used for basis of the model were not available for review. Based on the

21   outputs, the model does not appear to predict significant flooding in the vicinity of

---

[17]   *See* Kolker Testimony at p. 9.

1   NOPS. Due to the large scale of the model, it is likely that conservative assumptions were

2   used, and the model is intended for evaluating regional impacts and not flooding in any

3   discrete area without additional supporting modeling. I would be hesitant to use the

4   model Dr. Kolker relies upon to evaluate flood risk of a specific, local area.

5

6   Q50.   DOES THE SPECIFIC SITE DESIGN OF NOPS MITIGATE THE RISK OF DAMAGE

7   DUE TO FLOODING IN THE 10-YEAR RAINFALL SCENARIO DR. KOLKER

8   DESCRIBES?

9   A.   While Dr. Kolker's description of his scenario is not specific enough to definitely

10   evaluate this risk, as noted in Jonathan E. Long's Supplemental Direct Testimony, the

11   proposed TOC of the proposed NOPS is 1 foot higher than the observed Hurricane

12   Katrina flooding and 2.5 feet higher than the recommended FEMA flooding elevation.

13   Based on the information available, it appears that the planned elevation of the NOPS site

14   is sufficient to protect against flood risk. As noted above, Dr. Kolker's testimony does

15   not appear to have taken this into account.

16

17   Q51.   HAVE YOU REVIEWED THE SET OF PROBABILITIES DR. KOLKER LISTS IN

18   TABLE 1 OF THIS TESTIMONY?

19   A.   Yes.

20

21   Q52.   DOES THAT TABLE PROVIDE AN ACCURATE DEPICTION OF THE "CHANCE

22   OF FLOODING" DURING THE LIFE OF NOPS, AS DR. KOLKER HAS

23   REPRESENTED TO THE COUNCIL?

1   A.   No. Dr. Kolker's description of the table is misleading. While the table does present the

2   chance of a 100-year storm, it does not directly relate to flooding. In the paragraphs

3   preceding Table 1, Dr. Kolker describes how the 2012 Master Plan predicts no flooding

4   in a 100-year storm, but he includes those values in the Table as corresponding to a

5   "chance of flooding." This is an internal inconsistency within Dr. Kolker's analyses.

6   Moreover, as noted above, the 2017 Master Plan takes into account the 500 year and 100

7   year events and predicts no flooding at the proposed NOPS location. Regardless, Table 1

8   shows probabilities of representative rainfall events, but it does not present the

9   probability of flooding, contrary to what Dr. Kolker has represented to the Council.

10

11   Q53.   HAVE YOU REVIEWED DR. KOLKER'S ANALYSIS OF "THE RANGE OF

12   RELATIVE SEA LEVEL RISE SCENARIOS FOR THE AREA AROUND THE

13   PROPOSED NOPS"[18]?

14   A.   Yes.

15

16   Q54.   WHAT IS YOUR OPINION ABOUT THE VALIDITY OF DR. KOLKER'S

17   CALCULATIONS OF RELATIVE SEA LEVEL RISE?

18   A.   Dr. Kolker's analysis uses conservative assumptions about sea-level rise and the flawed

19   assumption that subsidence will continue at a steady rate over the next 50 years. The

20   calculations do not take into account the protection of the HSDRRS and are therefore an

21   invalid basis on which to assess flood risks for the proposed NOPS site.

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[18]   *See* Kolker Testimony at p. 9-10.

1

2   **VIII.   CONCLUSION**

3   Q55.   WHAT WOULD YOU REPRESENT TO THE COUNCIL ABOUT ANY CONCERN

4   RELATED TO GROUNDWATER USAGE FROM EITHER THE CT OR THE

5   ALTERNATIVE   PEAKER   POTENTIALLY   CAUSING   DAMAGE   IN   NEW

6   ORLEANS EAST DUE TO GROUNDWATER WITHDRAWAL?

7   A.   I would assure the Council that given the location, the subsurface conditions, the history

8   of groundwater usage, and the proposed groundwater withdrawal rates, usage from either

9   the CT or the Alternative Peaker has no potential for causing damage in New Orleans

10   East due to groundwater withdrawal.

11

12   Q56.   WHAT IS YOUR OPINION OF DR. KOLKER'S RECOMMENDATIONS TO THE

13   COUNCIL?

14   A.   The additional studies Dr. Kolker recommends related to subsidence and flood risks are

15   unnecessary because the analysis undertaken for the C-K Technical Report was based on

16   geotechnical data, hydrogeological data, soil boring logs, well construction logs, the

17   CPRA master plan, and other reports that considered storm surge models and climate

18   projections. The C-K Technical Report used this information to develop a

19   geotechnical/hydrogeological conceptual site model, which was presented in the Report.

20   The Addendum to the C-K Techncial Report presents a more detailed analysis of

21   concerns related to subsidence and ground water usage and concludes that operation of

22   either the CT or the Alternative Peaker will not exacerbate subsidence in New Orleans.

23

1   Q57.   DOES DR. KOLKER'S TESTIMONY PROVIDE ADEQUATE SUPPORT FOR HIS

2   CONCERNS RELATED TO NOPS?

3   A.   No.

4

5   Q58.   DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

6   A.   Yes.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF _East Baton Rouge_

NOW BEFORE ME, the undersigned authority, personally came and appeared, **GEORGE LOSONSKY, PH.D., P.G.**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

_____
Dr. George Losonsky, Ph.D., P.G.

SWORN TO AND SUBSCRIBED BEFORE ME
THIS _____ DAY OF JUNE, 2017

_____
NOTARY PUBLIC

My commission expires: _Upon death_

GEORGE LOSONSKY, Ph.D., P.G.

Groundwater and Soil Gas Flow and Transport Modeling

Environmental Remediation and Management

Well Design and Rehabilitation

Losonsky & Associates, Inc.

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Baton Rouge, Louisiana 70816

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225 293 0196 Fax

EDUCATION

University of Cincinnati: Ph.D., Hydrogeology and Sedimentology, 1992
University of Cincinnati: M.S., Physical and Chemical Processes in Geology, 1983
Oberlin College: B.A., Geology, 1980
University of Missouri-Columbia: Geology Field Camp, 1979

PROFESSIONAL HISTORY

Losonsky & Associates, Inc., 2005 -
CH2M HILL Inc., New Orleans, Louisiana, 2004- 2005
GeoSyntec Consultants, Baton Rouge, Louisiana, 2002 - 2004
IT Corporation/IT Group/Shaw Environmental & Infrastructure, 1992 – 2002
> IT Infrastructure & Environmental GmbH, Kaiserslautern, Germany, General Manager, 2000 – 2002
> Customer Program Manager, Concord, California, 1999 – 2000
> Engineering & Groundwater Technology Business Line Manager, Tampa and Clermont, Florida, 1997 – 1999
> Project Manager, Lake Charles, Louisiana/Houston, Texas, 1993 – 1997

Baker-Hughes/Eastman Christensen Environmental Systems, Houston, Texas, Environmental Applications Manager, 1991 – 1993
Midwest Water Resource, Inc., Lansing, Michigan, Chief Hydrogeologist, 1990 – 1991
U.S. EPA Center Hill Solid Hazardous Waste Research Facility, Cincinnati, Ohio, Geochemical Hydrologist, 1987 – 1989
University of Cincinnati, Cincinnati, Ohio, Instructor/Research Assistant/Teaching Assistant, 1980 – 1986

REPRESENTATIVE EXPERIENCE

Dr. Losonsky has over 30 years of experience in environmental and water resources problem solving and management. He has extensive experience in design, installation, testing and rehabilitation of production,

testing, monitoring, remediation and mitigation wells completed using hollow-stem auger, mud and air rotary, direct push technology, cone penetrometer testing, hydraulic fracturing, sonic drilling, downhole steerable mud motor drilling, and directional jetting tool drilling. His experience includes logging, correlating and modeling a wide variety of sedimentary, metamorphic and igneous basins and tectonic systems worldwide. Through his academic background and work experience he has gained in-depth, working knowledge of the physical and chemical mechanisms governing groundwater flow and production, aquifer management, and both soil vapor and groundwater plume migration. He has developed and managed soil and groundwater remediation or vapor mitigation programs at military bases, chemical plants, drycleaning facilities, petrochemical refineries, fuel storage facilities, hazardous waste landfills, food processing plants, pharmaceutical industry facilities, and various manufacturing plants. He has assisted in the development of state and regional environmental assessment, remediation, and risk evaluation programs for the drycleaning and retail petroleum industries. He helped organize a vapor intrusion guidance development videoconference between USEPA Region 6 and state regulators. Dr. Losonsky served from 2007 - 2012 on the Board of Commissioners of the Southeast Louisiana Flood Protection Authority-East.

Dr. Losonsky is a recognized expert in subsurface remediation and water supply using horizontal wells, has published numerous technical papers and taught seminars on this subject, and is a founding member of the Horizontal Environmental Technical Committee of the National Ground Water Association, for which has served as Chairperson of the Horizontal Well Interest Group and editor of Horizontal News. Dr. Losonsky was among the pioneers of horizontal environmental wells as Manager of Environmental Applications for Baker Hughes/Eastman Christensen in the early 1990's, and since then he has designed and managed construction and operation of innovative horizontal well systems for the Department of Defense, Brownfields programs, municipal water systems, real estate developers, drycleaners, petroleum retailers, and the chemical industry.

As a member of the US Environmental Protection Agency (USEPA) Remedial Technologies Development Forum (RTDF) on In Situ Flushing Technologies, the Interstate Technology and Regulatory Cooperation Work Group (ITRC) on *In Situ* Chemical Oxidation of Contaminated Soil and Groundwater, and the National Ground Water Association's Water Well Grouting and Decommissioning Task Groups, and the USEPA Risk Reduction Engineering Laboratory/Center Hill Research Facility, Dr. Losonsky has helped develop regulatory guidance and national strategies for implementation of water wells and of hydraulic fracturing, surfactant, co-solvent, partitioning tracer and chemical oxidation technologies for subsurface remediation.

As technical manager, he has applied multiphase, fractured-media flow modeling, statistical modeling, plume stability prediction, and three-dimensional visualization to site characterization, and he has used a wide range of in-situ remedial technologies, including soil vapor extraction, multiple phase extraction, air sparging, bioremediation, chemical oxidation, surfactant flushing, hydraulic fracturing, and electrical resistance heating. In addition to his focus on *in situ* remediation, Dr. Losonsky's experience as a hydrogeologist includes design and operation and maintenance of pump-and-treat, treated groundwater re-injection, municipal water extraction and distribution, pumping-monitoring systems, vapor mitigation systems and agricultural non-point source control systems in diverse and complex hydrogeologic settings. Dr. Losonsky has worked in North America, Europe, Africa, Australia, Japan, and South Korea.

EXPERIENCE AND BACKGROUND

- Provides environmental site management, well design and performance testing, well rehabilitation, hydrogeologic and water resources evaluation, real time high resolution site characterization, groundwater and vapor transport modeling, remedial design services worldwide:

  - Losonsky & Associates, Inc., volunteered its efforts and resources in aiding victims of hurricanes Katrina and Rita, and of the Southeast Louisiana flood of August 2016. Dr. Losonsky has supported the hurricane and flood protection efforts in Louisiana through his service as Commissioner of the Southeast Louisiana Flood Protection Authority-East.

  - Environmental Claims Management, Mansfield, Texas. Completed Louisiana Risk Evaluation Corrective Action Program (RECAP) risk assessment for Collette Oil Company site in Baton Rouge, Louisiana.

  - Eagle Environemntal Services, Inc., Baton Rouge, Louisiana.Designed and executed aquifer testing program, including slug tests and multi-zone pumping tests to determine groundwater classification in Mississippi River related sedimentary deposits.

  - Senversa Pty Ltd, Adelaide, Australia. Provided hydrogeologic and geochemical analysis in support of an investigation of the effects of copper mining slag emplacement in the former Korrongulla swamp in Primbee, New South Wales.

  - Eagle Environmental Services, Shreveport, Louisiana. Evaluated groundwater-surface water interaction to determine impact of petroleum hydrocarbon impacts on stream water. Designed and implemented in situ remediation system of alluvial sediments using direct push technology to deliver chemical oxidants.

  - CH2MHILL, Marietta, Ohio. Completed horizontal well design review for air sparge system in heterogeneous sand, gravel and clay deposits.

  - Arcadis US, Inc. and Department of Defense Environmental Security Technology Certification Program. Performed hydrogeological and geotechnical evaluation and analysis in support of the Demonstration and Validation of the Horizontal Reactive Media Treatment (HRX) well for Managing Contaminant Plumes in Complex Geological Environments program.

  - Ramboll Environ, Baton Rouge, Louisiana. Evaluated groundwater withdrawal well field design, calculated water well drawdown, and assessed salt water intrusion in Chicot aquifer in southwest Louisiana. Evaluated alternative horizontal well design for mitigating salt water intrusion.

  - Confidential client, Fort Collins, Colorado. Designed horizontal trench in gravel aquifer for high-volume groundwater recovery for long-term dewatering.

  - CH2M HILL, Anchorage, Alaska. Performed hydrogeologic analysis in support of groundwater remediation system for the Former Galena Forward Operating Location. Designed eight horizontal wells in coarse sand and gravel sediments with large seasonal water level fluctuations.

  - Arcadis US, Inc., Bethpage, New York. Supported design of a groundwater withdrawal well to be installed 600 to 650 feet deep in glacial coastal plain sediments. The well required entry 1300 feet laterally displaced from well screen location in a logistically challenging urban setting in Bethpage, New York. The evaluation included consideration of directional drilling methods for deep water well installation.

- Parsons Environment and Infrastructure Group, Inc., Houston, Texas. Designed infiltration gallery using continuous trenching methods featuring two overlapping trench sections. Treated water from pump-and-treat system in nearby source area is infiltrated into the subsurface, acting as a hydraulic barrier downgradient of the source area and accelerating groundwater restoration.

- Senversa Pty Ltd, Adelaide, Australia. Provided Environmental Auditor support for the hydrogeologic evaluation of the Management Plan for Placement of Water Treatement Residuals to Hillbank Quarry. Evaluated leachate transport modeling in vadose and phreatic zones, aquifer testing, and post placement groundwater monitoring programs for four quarries in complex, fractured granite, metamorphic, and sandstone environments.

- Arcadis US, Inc. and Ford Motor Company, Developed specifications for a 2000 foot long hydraulic barrier system consisting of three horizontal wells to prevent offsite migration of groundwater contaminant plumes in heterogeneous sedimentary depositional environment.

- Senversa Pty Ltd, Sydney, Australia. Developed hydrogeologic testing and assessment strategy for the Country Fire Authority to address perfluorinated compounds (PFCs) in groundwater in a complex basaltic extrusive regime, including lava tube formations, in Penshurst, Victoria.

- Senversa Pty Ltd, Melbourne, Australia. Assisted in site characterization and remedial alternatives development for CSL pharmaceutical manufacturing facility in Parkville, Victoria.

- CH2M HILL, Charlotte, North Carolina. Evaluated aquifer testing and groundwater modeling results at the Union Carbide/DOW Texas City facility and designed a horizontal extraction well to remediate a chlorinated hydrocarbon impacts in groundwater.

- Eagle Environmental, Baton Rouge, Louisiana. Compiled database of subsurface hydrogeologic data based on 30 years of site investigation at Rubicon-Huntsman chemical manufacturing facility in Geismar, Louisiana, and developed 3-D model of site hydrogeology and organic compound constituent groundwater plumes. Assisted in preparation of site-wide conceptual site model as part of a corrective action framework required by Louisiana Department of Environmental Quality and U.S. Environmental Protection Agency.

- Senversa Pty Ltd, Melbourne, Australia. Evaluated efficacy of LNAPL recovery trench and assisted in developing sitewide remedial strategy at South Dynon Rail Yard, VicTrack, Docklands, Victoria.

- Senversa Pty Ltd, Melbourne, Australia. Evaluated in situ chemical oxidation pilot trials using potassium permanganate and ozone at Bosch Chassis Systems Manufacturing Facility, East Bentleigh, Victoria, performed remedial technology alternatives screening, and assisted in developing probabilistic cost estimate of site closure costs for confidential client.

- Senversa Pty Ltd, Melbourne, Australia. Evaluated long-term plume stability monitoring data at Former North Geelong Gasworks manufactured gas plant and identified appropriate geostatistical tools and decision tree to determine monitoring endpoints.

- Senversa Pty Ltd, Melbourne, Australia. Designed horizontal multiple phase extraction well system for BP facility in Geelong, Victoria, Australia.

- CH2M HILL, Atlanta, Georgia. Designed a shallow horizontal soil vapor extraction well to operate concurrently with horizontal air sparging wells crossing multiple roads at Savannah Air National Guard site in Garden City, California.

- Senversa Pty Ltd, Adelaide, Australia. Provided regulatory audit review of groundwater fate and transport model supporting site clean-up strategy for the Nyrstar Port Pirie smelter and refinery, Port Pirie, South Australia.

- CH2M HILL, Charlotte, North Carolina. Designed horizontal wells for potassium permanganate tracer study at Marine Corps Base Camp LeJeune, North Carolina.

- Senversa Pty Ltd, Adelaide, Australia. Provided regulatory audit review of vadose zone fate and transport model and supporting metals leach testing for the assessment of water treatment residuals from water treatment plants as rehabilitation material for placement at various rock quarries in South Australia by the South Australian Water Corporation.

- S.M. Stoller Corporation, Largo, Florida. Served as horizontal well expert in project team responsible for scope of work development, engineering and construction contractor procurement, and supervision of design, installation, operation and maintenance of a horizontal well bioremediation amendment injection system at a legacy Department of Energy facility.

- American Electric Power, Gallipolis, Ohio. Assisted in pilot trial of mercury emissions control technology at James M. Gavin coal-fired power plant in Cheshire, Ohio.

- S&ME, Inc., Greensboro, North Carolina. Contributed to a corrective action plan for Novozymes North America using numerical groundwater flow and transport modeling to address non-point source nitrate and TDS impacts of a regional drinking water aquifer in partially weathered and unweathered, fractured igneous and metamorphic formations, including long-term plume stability projections and optimization of locations, flow rates and screen intervals of recovery wells.

- Du Pont de Nemours and Company, Oakley, California. Developed technical specifications and requirements for horizontal bioremediation amendment injection wells at various depths at a former chemical manufacturing facility that produced chlorofluorocarbons, anti-knock compounds and titanium dioxide. Completed a sensitivity analysis of the effect of viscosity of the bioamendment solution.

- Senversa Pty Ltd, Australia. Provided expert independent review of groundwater flow and reactive transport model and related sequential batch leach testing to assess metals plume stability and risk to surface water at the Former Port Kembla Copper Smelter and Refinery, Port Kembla, New South Wales, for Port Kembla Copper Pty Ltd.

- Arcadis U.S., Inc., Augusta, Georgia. Designed a horizontal hydraulic barrier well for a rail operating facility to protect an offsite, down-gradient residential neighborhood. The well fills a gap in an existing hydraulic barrier system in a strongly heterogeneous shallow water-bearing zone consisting of sandy clay and clayey sand. Assisted in contractor procurement, prepared well development protocol, and provided guidance during well development.

- Senversa Pty Ltd, Adelaide, Australia. Evaluated solvent plume migration at General Motors Holden automobile parts manufacturing facility in Elizabeth, South Australia.

- Senversa Pty Ltd, Melbourne, Australia. Provided regulatory audit review of site characterization and corrective action plan for a solvent plume in mixed igneous and sedimentary environment with complex porosity distribution at Ericsson manufacturing site in Preston, Victoria, Australia.

- CH2M HILL, Charlotte, NC. Designed system of horizontal biosparging and soil vapor extraction wells in petroleum hydrocarbon impacted silty sands at a pipeline facility.

- CH2M HILL, Charlotte, NC. Developed a treatability study for horizontal soil vapor extraction design at Pearl Harbor-Hickam Air Force Base, Hawaii. Designed a system of horizontal subslab extraction wells to mitigate vapor intrusion.

- Senversa Pty Ltd, Melbourne, Australia. Supervised installation and development of a 900-foot horizontal soil vapor extraction well installed in fractured basalt rock under an automobile manufacturing facility. Conducted extensive performance testing of the horizontal well, evaluating both flow and diffusion effects. Conducted an efficiency test of a vertical soil vapor extraction system at the same facility and performed a performance evaluation comparing the horizontal and vertical soil vapor extraction systems.

- Shavers-Whittle Construction LLC and Professional Technical Support Services, Inc., New Orleans, Louisiana. Developed and supervised installation of emergency coffer dam dewatering system for drainage canal construction.

- Professional Technical Support Services, Inc., Newport News, Virginia. Designed and supervised installation, development and performance testing of horizontal water supply system at coal shipping terminal.

- CH2M HILL, Atlanta, GA. Designed system of horizontal soil vapor extraction wells and a horizontal potassium permanganate injection well at Tinker Air Force Base, Oklahoma.

- C-K Associates, Houston, Texas. Compared horizontal well and trench system specifications and installation requirements for petroleum and metals migration control at oil and gas production facilities, west Texas.

- Eagle Environmental, Baton Rouge, Louisiana. Developed high volume horizontal water supply well system design for power plant.

- KCH/Naval Facilities Engineering Command Hawaii. Prepared treatability study report for horizontal soil vapor extraction well design.

- CH2M HILL, Atlanta, Georgia. Designed variable application horizontal air sparge and biosparge wells for chlorinated hydrocarbon remediation at chemical manufacturing facility in Marietta, Ohio.

- Senversa Pty Ltd, Melbourne, Australia. Horizontal soil vapor extraction well feasibility evaluation and design for basaltic rock at automobile manufacturing facility.

- CH2M HILL, Marietta, Georgia. Performed numerical multiphase transport modeling of gas flow through the saturated and unsaturated zones to assess the effectiveness of a horizontal air sparge well remediation system. Assisted in the design and implementation of a sulfur hexafluoride and helium tracer injection test of a 1000-foot horizontal air sparge well at a defense contractor facility. Used gas transport modeling to optimize the flow rate and cyclic injection schedule of the horizontal air sparge well system.

- Louisiana Department of Environmental Quality, Sulphur, Louisiana. Developed Triad real-time mobile laboratory-driven site characterization at state-owned orphaned former waste impoundment site. Prepared corrective measures screening study.

- GES Environmental Services, confidential clients, New York. Designed combination air sparge and soil vapor extraction systems using horizontal wells in highly heterogeneous hydrogeologic settings.

- CB&I, Baton Rouge, LA. Prepared feasibility study for horizontal methane gas relief wells at the Bayou Corne sinkhole, Louisiana.

- Save Lake Peigneur, New Iberia, Louisiana. Prepared critique of salt dome cavern permit application to Louisiana DNR by Jefferson Island Storage & HUB LLC.

- Golder Associates and Directional Technologies, Inc. Designed and oversaw installation of 600-foot horizontal hydraulic barrier well at waste oil impoundment facility in Zapata, Texas.

- Woodard & Curran and Directional Technologies, Inc. Tewksbury, Mass, Designed and variable use, SVE and subslab depressurization system of horizontal wells under 500,000 square foot manufacturing facility. Provided site QC support during installation.

- AECOM and Directional Technologies, Inc. Designed and provided QA/QC and real-time wellhead surveying guidance for the installation of two blind 550-foot long horizontal multiple-phase extraction wells at a coke manufacturing facility in Port Lavaca, Texas, June 2012.

- AMEC and Directional Technologies, Inc. Designed and provided QA/QC and real-time wellhead surveying guidance for the installation of four blind air sparge and four blind soil vapor extraction wells at an industrial site in downtown Tallahassee, Florida August 2012.

- Alliance for Site Closure, LLC. Designed high-resolution triad investigation for the Concord Custom Cleaners drycleaner site in Michigan City, Indiana, utilizing mobile laboratory real-time data analysis of drycleaning solvent plume in groundwater under a residential neighborhood, including geochemical and geotechnical parameters required for three-dimensional numerical flow and transport modeling to assess plume migration and determine timeframe for reaching plume stability. Constructed multilayer numerical model simulating hydraulic gradient adjustments to changing drought conditions and changes in recharge caused by construction and storm drains. Identified discrete groundwater flow and contaminant transport channels and horizons within layered and vertically anisotropic hydrostratigraphy.

- Pacific Crest Environmental, North Bend, Washington. Designed system of two horizontal air sparge wells and two horizontal soil vapor extraction wells at Marine Iron Works, Tacoma, Washington.

- Specialty Earth Sciences, LLC. Designed horizontal blind well soil vapor extraction system at drycleaner site in Indianapolis, Indiana.

- Groundwater & Environmental Services, Inc. Designed and supervised the installation of a horizontal air sparge and soil vapor extraction well pilot system at John F. Kennedy International Airport, Jamaica, New York.

- Sesco Group, Indianapolis, Indiana. Designed and implemented a high-resolution Triad investigation for former Harmon Becker manufacturing plant in Martinsville, Indiana, using direct sampling ion trap mass spectrometer mobile laboratory to isolate multiple source areas beneath a large manufacturing building and in adjacent residential and commercial neighborhoods. Constructed and calibrated a three-dimensional flow and transport model to simulate chlorinated solvent plume migration and to design an enhanced in situ bioremediation program using whey as carbon source. Recalibrated model post-bioremediation to assess reductive dechlorination progress.

- FPM Corporation. Designed horizontal subslab vapor mitigation pilot well at Griffiss Air Force Base, Rome, New York.

- O'Brien & Gere Engineers, Inc. Designed horizontal subslab air extraction mitigation system at General Motors Plant in Syracuse, New York.

- Sesco Group, Indianapolis, Indiana. Planned and implemented environmental site investigation for D.E. Markeys of over 2 km long chlorinated hydrocarbon plume migrating through multiple aquifer zones separated by a series of fractured aquitards creating varying degrees of leakance. Developed and implemented multiple three-dimensional pumping tests for acquiring horizontal and vertical hydraulic conductivity and anisotropy values using multilevel and multiple completion monitoring wells. Developed a three-dimensional, finite difference groundwater flow and transport model with a 10 km^2 area model domain to predict plume migration and stability in various aquifer zones. Used flow and transport model to determine acceptable locations and production rates for water wells used by a greenhouse operation, irrigation wells, and residential water wells.

- CH2M HILL, Inc., Waukegan, Illinois. Provided QA/QC of 1000-foot long horizontal air sparge barrier well at OMC Plant 2 Superfund site.

- Roux Associates, Inc., Rochelle Park, New Jersey, supervised the installation of six-inch diameter black iron pipe dual-purpose soil vapor extraction wells and horizontal electrodes for in-situ six-phase heating of impacted soils beneath a manufacturing facility.

- Groundwater & Environmental Services, Inc. Designed and supervised the installation of two horizontal air sparge wells and one horizontal soil vapor extraction well in gravelly, boulder-rich soils at a retail gas station in Winsted, Connecticut.

- Weston Solutions, Inc., and Professional Technical Support Services, Inc. Designed and implemented a rehabilitation program for a horizontal hydraulic barrier well at a chemical manufacturing facility in Deer Park, Texas. The well was rehabilitated without mobilization of a directional drilling rig.

- Parsons Engineering and Professional Technical Support Services, Inc., Pascagoula, Mississippi. Designed and implemented a rehabilitation program for a 1000-foot groundwater recovery at a chemical manufacturing facility. The rehabilitation program avoided the use of a drilling rig or other heavy equipment.

- Sesco Group, Indianapolis, Indiana. Designed and implemented a whey injection system to pilot test chlorinated hydrocarbon impacts to groundwater at Bowes manufacturing in Indianapolis. Used system performance data to construct and calibrate a three-dimensional numerical groundwater flow and transport model for the purpose of evaluating long-term impact of the pilot test, and to design full-scale remediation.

- MACTEC Engineering and Consulting, Tallahassee, Florida. Designed and supervised the installation of four horizontal air sparge wells and four horizontal soil vapor extraction wells under a retail gasoline station, a high-density residential neighborhood, a major U.S. highway intersection, and a fast-food restaurant and parking lot. The wells were between 600 and 900 feet long, and 35 to 50 feet deep. Designed screen slotting to achieve even flow distribution for air injection and extraction.

- Shaw Environmental & Infrastructure, Inc., Trenton, New Jersey. Designed and supervised the installation of four horizontal wells under an office building and parking lot for potassium permanganate injection at the Former Raritan Arsenal Site, a former U.S. Army facility redeveloped under the U.S. EPA Brownfields program. Designed screen slotting to achieve even fluid injection. Used three-dimensional, finite difference flow and transport modeling to predict

aquifer response and permanganate transport, and to manage the injection and monitoring program.

- S&ME, Inc., Greensboro, North Carolina. Performed three-dimensional numerical groundwater modeling to help design vertical and horizontal groundwater remediation wells to address non-point-source pollution in a complex igneous and metamorphic setting that includes fractured granitic formations, diabase intrusives, weathered bedrock, and saprolite. Developed groundwater model to compare hydraulic effectiveness of vertical and horizontal wells for hydraulic barriers and local dewatering.

- CH2M HILL, Chicago, Illinois. Designed two horizontal well groundwater extraction systems for site-wide dewatering and multiple-phase extraction systems at railroad sites in Phoenix, Arizona, using three-dimensional, finite difference groundwater flow modeling. Predicted short-term and long-term flow rates and troughs of groundwater depression.

- CH2M HILL, Marietta, Georgia. Designed 3 horizontal air sparge wells and one SVE well at the Lockheed Martin manufacturing facility. Provided field supervision during the installation of the horizontal wells. The wells ranged in depth from 25 to 85 feet, and total well length ranged from 750 to 1050 feet. Two air sparge wells were placed along the edges of an LNAPL pool to prevent lateral spreading. A third, deeper air sparge well was placed along the axis of the LNAPL pool to reduce LNAPL thickness. The SVE well was placed below manufacturing buildings to prevent vapor intrusion.

- Franklin Company, Queens, New York. Provided design advice and installation oversight for TRC Co of New York, New York for 15 horizontal wells for bioamendment injection beneath multiple rail lines at the repair and maintenance terminal of the Long Island Rail Road in Queens, New York. The wells were installed around multiple generations of subsurface utilities. The soil was saturated with LNAPL resulting from 100 years of rail car maintenance operations.

- Professional Technical Support Services, Baton Rouge, Louisiana. Provided design and field implementation support for URS Corporation in Baton Rouge for structural repairs to subsurface sumps associated with horizontal wells at the DOW Plaquemine facility.

- SKA Consulting LLC, Houston, Texas. Used three-dimensional numerical groundwater flow modeling to design a system of vertical, multiple-phase extractions wells for localized dewatering of an unconfined aquifer, and rapid removal of petroleum hydrocarbons at a Brownfields/real estate development site.

- PPG Industries, Lake Charles, Louisiana. Provided hydrogeologic consulting services in support of management of the facility-wide Hazardous and Solid Waste Amendments (HSWA) program, including completion of a Corrective Measures Study, optimization of environmental well systems, and regulatory compliance in a multilayered system that includes fractured clays, alluvial sands, silts, and regional drinking water aquifers. Provided technical management of a sitewide RCRA Facility Investigation of chlorinated solvents in soil, sediment and groundwater using Cone Penetrometer Testing technology and statistical methods for three-dimensional evaluation of the horizontal and vertical extent of constituents. Applied innovative analytical testing methods for the assessment of sitewide distribution of Dense, Non-Aqueous Liquids. Participated in the development of a sitewide DNAPL management strategy. Designed and installed various corrective measures addressing solvents in a fluvial sedimentary setting comprising clay aquitard formations, regional drinking water aquifers, and intermediate water-bearing units.

- Shaw Environmental, Inc, Trenton, New Jersey. Provided design support for *in situ* chemical oxidation system at the Annapolis Towne Center-Parole Growth Management Area near Annapolis, Maryland, addressing extensive drycleaning solvent plumes. Designed 14 horizontal wells for injection of potassium permanganate at various depths, including screen design and groundwater flow and transport modeling. Designed 5 horizontal soil vapor extraction wells for solvents remediation beneath a drycleaning facility. Design included screen slotting specifications, and groundwater flow and transport modeling to specify well spacing and operational details of the injection system. Provided field QA/QC and oversight during horizontal well installation, which was concurrent with building foundation and infrastructure construction activities. Evaluated the efficacy of the injection system and recommended optimization measures using three-dimensional, finite difference groundwater flow and transport modeling.

- Royston Rayzor, Houston, Texas. Provided expert opinion on issues related to Hazardous and Solid Waste Amendments (HSWA) at a Citgo Petroleum facility in Lake Charles, Louisiana.

- URS Corporation, Baton Rouge, Louisiana. Developed rehabilitation program for a series of environmental horizontal wells at the Dow Chemical facility in Plaquemine, Louisiana, using camera survey and chemical evaluation. Provided field oversight during well rehabilitation.

- SKA Consultants, Houston, Texas. Presented series of 8-hour training seminars in basic hydrogeology, contaminant transport, geochemistry, and bioremediation.

- ERM Japan, Tokyo, Japan. Compiled a comprehensive survey of the most recent innovative tools for site investigation, remediation, and performance monitoring.

- Sesco Group, Indiana. Designed a horizontal biosparge and soil vapor extraction well system at the Rensberger bulk fuel storage facility in South Bend, Indiana, including air flow modeling, screen design, engineering specifications of horizontal and vertical wells, drilling plan and fluids management program, and surface plumbing design. Provided field supervision during installation and development.

- Environmental Standards, Charlottesville, Virginia. Developed procurement documents for horizontal well leachate collection system at a landfill, including conceptual design, performance specifications, and engineering specifications. Assisted in preparation for Public Meeting. Providing field supervision of horizontal well installation.

- Star Environmental, Orlando, Florida. Assisted in design, drilling plan, and contractor procurement for a horizontal groundwater sparging well installed under a highway and commercial building. Provided installation oversight and well materials QA/QC testing.

- Sesco Group, Indianapolis, Indiana. Designed horizontal bioventing well system at the Miller Oil petroleum bulk storage facility in Columbus, Indiana, including determination of corrective action objectives, air flow modeling, screen design, engineering specifications of horizontal wells, drilling plan and fluids management program. Provided field supervision during installation and development.

- Served as project manager for CH2M HILL, New Orleans, Louisiana, 2004-2005. Projects included:

- Phoenix Environmental, High Point, North Carolina. Developed a three-dimensional numerical groundwater flow and contaminant transport model of an 11 square mile area in fractured and weathered igneous and metamorphic Piedmont terrain, including simulation of non-point sources, fractures, and uptake of nitrogen by riparian vegetation in evapo-transpiration zones.

- PPG Industries, Lake Charles, Louisiana. Evaluated various groundwater remediation systems to determine their efficacy and relevance to corrective action objectives, and to recommend optimization measures. Provided guidance in development of Corrective Measures Study under the Louisiana Department of Environmental Quality Risk Evaluation Corrective Action Program (RECAP). Evaluated feasibility of in-situ chemical oxidation and bio-augmentation using field screening methods. Developed conceptual design of innovative methods of reactive barrier placement along shoreline.

- Union Carbide/Dow Chemical Corporation, St. Charles, Louisiana. Managed development and implementation of a facility-wide Risk Evaluation Corrective Action Plan (RECAP) strategy under the Louisiana Department of Environmental Quality RECAP program.

- DOW Chemical, Plaquemine, Louisiana. Evaluated management alternatives for optimizing sitewide environmental remediation program.

- Implemented hydrogeologic and environmental assessments and remediation designs for GeoSyntec in Baton Rouge, Louisiana, 2002-2004 including:

  - Honeywell International, Baton Rouge, Louisiana. Beneficial reuse evaluation of calcium chloride and effluent treatment sludge. Alternative uses in construction, agronomy, and waste management were identified based on a detailed analysis of chemical and geotechnical characteristics of the waste streams.

  - PPG Industries, Lake Charles, Louisiana. Designed and implemented an innovative program for testing and rehabilitation of a system of 9 horizontal DNAPL recovery wells in a former waste impoundment.

  - Florida Dept. of Environmental Quality. Developed Remedial Action Plans for facilities in the Hazardous Waste Division Statewide Drycleaner Cleanup Program. Remedial strategies included natural and enhanced attenuation, bio-augmentation, multiple phase extraction, and hydraulic control measures. Used finite difference groundwater flow and transport modeling results to optimize remediation systems.

  - National Aeronautics and Space Administration, Cape Canaveral, Florida. Designed multiple horizontal well groundwater injection and extraction system for in situ remediation of chlorinated solvents. The design featured parallel horizontal wells stacked vertically for shallow injection of chemical oxidant and deep extraction of treated groundwater. Fiberglass pipe dimensions and screen slotting configuration were specified to account for pipe strength requirements (including tensile and hoop stresses), effective roughness factor, slot aperture limitations, and open area requirements for gravity-driven injection of potassium permanganate solution. Well spacing and well paths were determined by calculated zones of influence, subsurface hydrogeology, topography, and anticipated drilling conditions to provide efficient delivery of potassium permanganate, and prevent venting problems during installation and operation.

  - SKA Consultants, Houston, Texas. Design, subcontractor procurement, and installation supervision of horizontal well multiple-phase extraction system for the Federal Reserve Bank of Dallas, Houston Branch, under a compressed schedule to accommodate bank construction. Two blind horizontal wells were designed to extract groundwater and liquid petroleum products from highly heterogeneous fluvial sediments. The horizontal wells have a gentle grade and intersect vertical sumps at their terminations in the subsurface, requiring a complex screen and sump design. Three-dimensional numerical groundwater modeling was used to design the well paths and screens, and to predict flow rates and dewatering zones. The site was successfully closed by

the TCEQ after approximately two years of operation. The horizontal well system has been nominated for the EPA's Phoenix award for best Brownfields project of the year in Region VI.

- Phoenix Environmental, High Point, North Carolina. Designed and conducted a series of week-long pumping tests to determine aquifer characteristics in igneous and metamorphic Piedmont terrain including fractured granite, diabase intrusions, and various degrees of near-surface weathering, in support of site characterization and numerical groundwater flow and contaminant transport modeling for Novozymes North America.

- Connelly, Baker, Wotring & Jackson, L.L.P. Evaluated groundwater remediation system design and cost estimate, including horizontal well system for the Port of Houston Authority. Contributed to cost reasonableness evaluation for assessment costs incurred during litigation. Evaluated consistency of three-dimensional hydrogeologic models used for predicting contaminant transport.

- Lombardo & Associates, Massachusetts. Evaluated feasibility of 7000-foot directionally drilled sewer line using river crossing technology.

- BFI/Ellender Ferry Landfill, Louisiana. Characterized subsurface stratigraphy and contaminant distribution.

- Bechtel/Cingular Wireless, Mississippi. Completed environmental audit at wireless tower locations in Mississippi.

- Waste Management/Vista Fibers, Baton Rouge. Conducted historical review of aerial photographs in support of Phase I environmental audit. Conducted Phase II site assessment.

- Founded and served as managing director of IT Infrastructure & Environmental GmbH in Kaiserslautern, Germany, in 2000-2002, serving Department of Defense programs for remediation and construction in Europe, and to collaborate with European partner companies in developing and implementing environmental infrastructure projects. Specific projects included:

  - Ramstein Air Base, Ramstein, Germany/Air Force Center for Environmental Excellence. Completed construction specifications, procured German subcontractors, and supervised field construction for groundwater extraction and reinjection wells in fractured sandstone regional drinking water aquifer underlying Petroleum Oil Lubricants underground storage facility. Designed and implemented enhanced delivery and recovery using hydraulic fracturing.

  - Ramstein Air Base, Ramstein, Germany/Air Force Center for Environmental Excellence. Supervised completion of engineering specifications, procured German subcontractor, and negotiated installation and operation and maintenance contract for 200 gallon per minute groundwater treatment system, including underground piping, pretreatment for iron separation, activated carbon adsorption, and air stripping.

  - Ramstein Air Base, Ramstein, Germany/Air Force Center for Environmental Excellence. Developed and implemented program of monitored natural attenuation of petroleum hydrocarbons plume at storage tank facility.

  - Ramstein, Vogelweh, Sembach, and Landstuhl Air Bases, Kaiserslautern, Germany/Air Force Center for Environmental Excellence. Implemented multiple-base program of inspection and removal of oil-water separators and grease traps at diverse military support facilities, including engine repair and testing buildings, runways, taxiways, liquid oxygen plants, and food service facilities. Negotiate permits with German regulatory agencies.

- NATO Strategic Headquarters Allied Partners Europe, Mons, Belgium/US Army Corps of Engineers. Managed structural investigation, including force protection requirements, of military barracks building for purpose of preparing cost-benefit analysis of building renovation.

- AK Chemie, Biebesheim, Germany. Performed field sampling and laboratory bench testing program to evaluate the feasibility of bio-augmentation and chemical oxidation of soil and groundwater contaminated with organic lead compounds.

- Thrallcar/Vagonka Studenka, Ostrava, Czech Republic. Completed detailed environmental audit of 100-year-old rail car manufacturing facility in the Czech Republic for a potential U.S. investor.

- Ministry of Environment, Wojwodina of Silesia, Poland. Participated in flood control management program for communities along the Odra River.

- Ludwigshafen and Munich, Germany. Contributed to program of brownfields development, including financing, remedial measures cost estimating, and property redevelopment concept definition, at former railroad facilities in urban/industrial districts.

- Designed and implemented pilot tests for IT Group at various locations in Japan in 1999-2001 to demonstrate *in situ* remediation technologies for Kurita Water Industries, including chemical oxidation and electrochemical geo-oxidation. Designed and implemented potassium permanganate injection system using hydraulic fracturing technology to achieve mass reduction and migration control of chlorinated solvents in lacustrine clay and silt formations at a specialized components manufacturing facility. Helped design pump-and-treat systems. Facilitated negotiations in 2001-2002 between Kurita Water Industries of Japan and several potential German partner companies specializing in electrochemical in-situ methods, permeable reactive barriers, soil washing, and mechanochemical dehalogenation of PCBs, Dioxin, and other halogenated organic compounds in soils and industrial materials.

- Managed and developed client programs for IT Group in California in 1999-2000 for management of solvents contamination, including food service industry, dry cleaners, retail petroleum, and landfills. Developed horizontal well drilling and testing programs. Managed evaluation and implementation of innovative in situ remediation technologies, including chemical oxidation and hydraulic fracturing. Specific projects included:

  - Nestle USA, Burbank, California. Managed groundwater contamination from decaffeination process. Remediation strategy included Potassium permanganate pilot test, and groundwater modeling to improve municipal water supply management. Managed groundwater modeling for developing large-volume municipal water extraction and distribution strategy for City of Ripon, California.

  - Chevron USA, Pleasanton, California. Developed nationwide strategy for evaluating risk of MtBE contamination of local water supply by retail stations, with focus on California, Texas, Florida, and Louisiana. Managed development of GIS database cross-referencing hydrogeological, chemical, and demographic factors.

  - Kelly Air Force Base, Texas. Designed, procured contractor, and evaluated efficiency of horizontal well system for hydraulic control of volatile organic compound contamination. Developed drilling and installation specifications for horizontal wells, designed aquifer test, and performed groundwater modeling.

  - Panoche Landfill, Benicia, California. Served as technical supervisor and regulatory interface for closure of IT Corporation Waste Management Units.

- Lockheed-Martin, New Orleans, and Kurita Water Industries, Japan. Designed, implemented and evaluated hydraulic fracturing program for enhanced delivery and recovery in low-permeability sediments.

- Provided continuing technical management support of Florida DEP Hazardous Waste Division Drycleaners cleanup program.

- Managed IT Group environmental engineering consulting business line in Tampa, Miami, and Clermont (Orlando), Florida in 1997-1999. Program activities included:

  - Directed Florida DEP Hazardous Waste Division Drycleaners cleanup program, in which CPT technology, geo-statistics and 3-D visualization are employed to isolate specific points of release, and optimal site closure strategies are developed by applying hydraulic analysis, natural attenuation evaluation, and innovative remedial technologies, such as passive iron walls, horizontal wells, and chemical oxidation.

  - Directed Florida DEP Pre-approval and State Lead programs, in which site closure strategies are combined with pay-for-performance criteria. Managed and contributed to site characterization using Cone Penetrometer Testing technology and statistical methods of indicator kriging to produce three-dimensional models of the extent of drycleaner solvents and their daughter products in hydrogeologic settings representing varying degrees of heterogeneity. Used cost-effective methods of three-dimensional groundwater modeling to develop site-specific remedial strategies, and used spatial rendering of solvent plumes to optimize remediation systems. Helped design standardized methodologies for drycleaner site characterization and remedial alternatives screening for the state-wide drycleaner program.

  - Supported Department of Defense Business Development initiatives at various Air Force Bases in Florida. Helped implement technology demonstration pilot testing at Cape Canaveral for NASA and Patrick Air Force Base.

  - Provided regulatory support, ecological risk assessment, and wetlands reconstruction.

  - Provided litigation support for cases involving DNAPL contamination and brine waste.

- Co-managed assessment and remediation activities as Task Manager for IT Corporation's project office at PPG Industries, Lake Charles, Louisiana in 1992-1998 for Resource Conservation and Recovery Act (RCRA) Facility Investigation (RFI) and Corrective Measures Study. Activities included:

  - Developed design specifications, procured installation contractor, and tested horizontal well systems, including nine horizontal wells for dense, non-aqueous phase liquid recovery in a waste impoundment.

  - Performed geotechnical evaluation of consolidation settlement effects due to groundwater recovery.

  - Implemented water flooding through trenches to enhance DNAPL recovery.

  - Managed surfactant flushing pilot test project; evaluated full-scale feasibility.

  - Managed flow and transport modeling, including multiple phases and fractured media.

  - Helped develop DNAPL management strategy for large, complex industrial site.

  - Developed and implemented multilevel cone penetrometer testing and sampling program for hydrogeologic characterization of DNAPL-contaminated system.

- Managed development of 3-D visualization techniques for contamination assessment and salt dome solution mining.

- Evaluated horizontal well system effectiveness at Williams Air Force Base, Arizona.

- Managed environmental horizontal drilling projects for Baker-Hughes/Eastman Christensen Environmental Systems, Houston, Texas, 1991-1993. Activities included:

  - Designed and installed horizontal well systems.

  - Managed software development for hydrogeological and hydraulic modeling of horizontal well performance.

  - Managed development of new products and product applications in the field of horizontal well installation and sampling.

  - Managed Health and Safety Program for horizontal drilling operations.

  - Developed nationwide customer base and defined marketing strategies.

  - Collaborated with AFCEE to develop horizontal well remediation system strategies for various Air Force Bases, including Brooks AFB, Kelly AFB, and Williams AFB.

- Managed hydrogeology division budget for Midwest Water Resource/MWR, Inc., Lansing, Michigan. Responsibilities included:

  - Directed environmental consulting activities of remediation and consulting company with approximately 30 employees.

  - Developed and implemented engineering strategies for soil and groundwater remediation systems for commercial clients, including Clark Equipment in Michigan; Taylor Forge in New Jersey, Chevron Industries in Indiana, and AIG/Herz-Penske in Ohio.

  - Coordinated research and development activities and defined research and development objectives.

- Managed, co-managed and participated in research projects at the Center Hill Research Facility/USEPA Risk Reduction Engineering Laboratory, Cincinnati, Ohio. Projects included contaminant transport modeling, hydraulic fracturing, bioremediation, steam and polymer injection, waste stabilization, and expert systems development. Specific activities included:

  - Co-developed method of increasing flow for delivery and recovery of fluids into unconsolidated materials, such as silts and clays, using hydraulic fractures. Conducted bench testing of fracturing techniques, including propant chemistry. Implemented technique at two pilot tests in Cincinnati, Ohio (Elda Landfill and Gettle Corp.), creating stacks of sand-filled fractures over 10 feet deep with up to 100 foot diameter. Helped design and build direct-push hydraulic fracture apparatus currently still in use by USEPA for full-scale field applications of hydraulic fracturing for enhancement of flow through soils with low permeability.

- Authored successful NSF grant proposal for $97K to study diffusive mass transport processes in porous media at the University of Cincinnati in Cincinnati, Ohio. Other activities as graduate research and teaching assistant included:

  - Compiled radiocarbon data for surficial processes study under NSF grant.

- Directed ion beam sample preparation for transmission electron microscopy to study composite materials.

- Taught ten courses and laboratory sections in geology and engineering geology.

FOREIGN LANGUAGES

Fluent in German, Czech, Slovak
Proficient in French

PROFESSIONAL AFFILIATIONS

Association of Engineering Geologists
Hazardous Materials Control Research Institute
National Ground Water Association
Association of Ground Water Scientists and Engineers
Sigma XI/The Scientific Research Society
American Chemical Society
Society of Economic Paleontologists and Mineralogists

PROFESSIONAL CERTIFICATIONS

Professional Geologist, licensed by Texas Board of Professional Geoscientists, License No. 2596
Professional Geoscientist, licensed by Louisiana Board of Professional Geoscientists, License No. 981
Traveling Workers Identification Card (TWIC)
40-hour OSHA training, 29 CFR 1910.120 and annual 8-hour refreshers
8-hour DOT training
12 Basic Plus Association of Reciprocal Safety Councils 8-hour training and annual 2-hour refreshers
DuPont Safety Management Training

LIST OF PUBLICATIONS

GEORGE LOSONSKY

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83-2   Losonsky, G., 1983, *The structural setting of tectonic stylolites in the Allegheny Plateau*, southeastern West Virginia [abstract], in Geological Society of America Abstracts with Programs, Vol, 15, p. 631.

84-1   Losonsky, G., 1984, *Stylolites, in Guidebook to Mammoth Cave*, Kentucky, University of Cincinnati.

88-1   Losonsky, G. and Pryor, W.A., 1988, *Burial depth, lithofacies, and stylolite density in the Salem Limestone, Illinois Basin [abstract]*, Society of Economic Paleontologists and Mineralogists Annual Midyear Meeting Abstracts, Vol. 5, p. 32.

88-2   Losonsky, G., 1988, *Chemical Stabilization/Solidification Database -- A User Guide*; Final Report. University of Cincinnati College of Engineering/U.S. Environmental Protection Agency Contract No. 68-03-3379; WA #1-4.

89-1   Potter, P.E., Losonsky, G., and Gilreath, J.S., 1989, 1989, *Kentucky River Fault System, US 27, Garrard County Kentucky -- Study Guide to Structure and Dipmeter Interpretation*. Kentucky Geological Survey Map Series.

89-2   Murdoch, L., Patterson, B., Losonsky, G., and Harrar, W., 1989, *A Review of Innovative Technologies of Delivery or Recovery for the Remediation of Hazardous Waste Sites*. Final Report, U.S. Environmental Protection Agency Contract No. 68-03-3379; WA #1-11.

89-3   McCandles, R., Keller, D., Isenberg, J., Losonsky, G., Moore, M., Williams, D., Proffit, S., Morress, C., Strube, P., Cheng, K.Y., and Barth, E., 1989, *Assessment of solidification/stabilization for Superfund contaminated soils [abstract/poster]*. 15th Annual EPA Research Symposium, April 10-12, 1989, Cincinnati, Ohio.

90-1   Murdoch, L.C., Patterson, B., Losonsky, G., and Harrar, W., 1990, *Technologies of Delivery or Recovery for the Remediation of Hazardous Waste Sites*, US Environmental Protection Agency Project Summary, EPA/600/S2-89/066.

90-2   Murdoch, L.C., Losonsky, G., Klich, I., and Cluxton, P., 1990, *Hydraulic Fracturing to increase fluid flow, in Contaminated Soil '90*, Arendt, F., Hinsenveld, M., and van den Brink, W.J., eds., Kluwer Academic Publishers, Netherlands, pp. 1087-1094.

91-1   Murdoch, L.C., Losonsky, G., Cluxton, P., Patterson, B., Klich, I., and Braswell, B., 1991, *The feasibility of hydraulic fracturing of soil to improve remedial actions*, US Environmental Protection Agency, Final Report, EPA/600/2-91/012 (NTIS PB91-181818).

91-2   Murdoch, L.C., Losonsky, G., Cluxton, P., Patterson, B., Klich, I., and Braswell, B., 1991, *The feasibility of hydraulic fracturing of soil to improve remedial actions*, US Environmental Protection Agency Project Summary, EPA/600/S2-91/012.

92-1   Losonsky, G., 1992, *Burial Depth and Lithofacies Control of Stylolite Development in the Mississippian Salem Limestone*, Illinois Basin, Ph.D. dissertation, University of Cincinnati.

92-2   Losonsky, G., and Beljin, M.S., 1992, *Horizontal wells in subsurface remediation, in Proceedings of HMC-South Conference*, Hazardous Materials Controls Research Institute, February 1992, New Orleans, pp. 75-80.

92-3   Losonsky, G., Jacques, G.E., and Beljin, M.S., 1992, *Ground water monitoring with horizontal wells*, in Proceedings of the Sixth National Outdoor Action Conference, National Ground Water Association, May 1992, Las Vegas, Nevada, pp. 189-204.

92-4   Lee, G. G., C. Keller, and G. Losonsky, 1992, *Short course on landfill monitoring systems*, held at Sixth National Outdoor Action Conference, National Groundwater Association, Las Vegas, 1992.

92-5   Karlsson, H., Losonsky, G., and Jacques, G.E., 1992, *Horizontal wellbore completions for aquifer restoration and their economics*, in Proceedings of Hazmat International 1992 Conference and Exhibition, June 1992, Atlantic City.

92-6   Beljin, M.S., and Losonsky, G., 1992, HWELL: *A horizontal well model, in Proceedings of Conference on Solving Ground Water Problems with Models*, International Ground Water Modeling Center and the Association of Ground Water Scientist and Engineers, February 1992, Dallas, pp. 45-54.

93-1   Kenda, W., and G. Losonsky, 1993, *Directional Drilling and Horizontal Well Completion Issues in Subsurface Remediation*, in IT Corporation Symposium Proceedings, Vol. III, Section 18: Groundwater and Vadose Zone Remediation, Paper No. 18-1.

93-2   Beljin, M. S., and G. Losonsky, 1993, *Enhancing site characterization with horizontal wellbores*, in Proceedings of the Sixth Annual Hazmat Environmental Management and Technology Conference/Central, pp. 406-416.

93-3   Bandeen, R., M. Beljin, and G. Losonsky, *Recovery of contamination groundwater with a horizontal well in a strongly heterogeneous aquifer--a pilot study [abstract]*, in rocky Mountain Groundwater Conference and 6th Annual New Mexico Section AWRA Conference, Albuquerque, New Mexico, October 27-29.

94-1   Losonsky, G., and Beljin, M.S., 1994, *Horizontal wells for subsurface pollution control*, in Handbook of Process Engineering for Pollution Control and Waste Management, Wise, D.L., and Trantolo, D.J., eds., Chapter 30, Marcel-Dekker, Inc., New York, pp. 619-633.

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94-3   Losonsky, G., M.S. Beljin, and D. D. Wilson, 1994, *Limitations of horizontal wells for environmental remediation in heterogeneous, anisotropic aquifers*, in Proceedings of Petroleum

Hydrocarbons Conference, National Groundwater Association/American Petroleum Institute, Houston.

94-4   Beljin, M.S., and G. Losonsky, 1994, *Hydrogeological characterization of hazardous waste sites with horizontal wells* [to be submitted to International Journal of Hydrogeology].

94-5   Wilson, D. D., and G. Losonsky, 1994, *Horizontal Environmental Wells: Design, Procurement and Installation*, National Groundwater Association Short Course Notes, Houston.

95-1   Wilson, David D., and Losonsky, G., 1995, *Cost evaluation methods for horizontal environmental wells*, in Drilling Technology 1995, J.P. Vozniak, ed., Proceedings of Energy and Environmental Expo 1995, American Society of Mechanical Engineers, Houston, January 1995, PD-Vol. 65, pp. 43-50.

95-2   Losonsky, G., Liu, K.-H., and Valentine, R., 1995, *Pumping tests to establish vertical hydraulic conductivity in a gulf coast alluvial sequence* [abstract], Proceedings of the 1995 Annual Meeting of the Association of Engineering Geologists and the Groundwater Resources Association of California, Sacramento, California, October 1995, p. 68.

95-3   Losonsky, G., and Landry, G.R., 1995, *Consolidation settlement in response to pump-and-treat remediation at industrial facilities*, in Drilling Technology 1995, J.P. Vozniak, ed., Proceedings of Energy and Environmental Expo 1995, American Society of Mechanical Engineers, Houston, January 1995, PD-Vol. 65, pp. 37-41.

95-4   Losonsky, G., and Landry, G.R., 1995, *Groundwater remediation system induced soil settlement: an estimation and management case study* [abstract], Presented at Superfund XVI Conference and Exhibition, HMCRI, Washington, D.C., November 1995.

95-5   Losonsky, G., and Landry, G.R., 1995, *Estimation and management of soil settlement at a chemical plant in response to groundwater withdrawal*, Proceedings of International Technology Symposium, Scottsdale, Arizona, August 1995.

95-6   Losonsky, G., Beljin, M.S., and Oakley, D.B., 1995, *The efficiency of a horizontal well for groundwater extraction at a hazardous waste site*, Proceedings of Superfund XVI Conference and Exhibition, Washington, D.C., November 1995, pp. 1550-1557.

95-7   Losonsky, G., *Horizontal well efficiency evaluation of well HW-1 at Williams Air Force Base*, Horizontal News, Volume 1/Number 2, Fall 1995, Colorado Center for Environmental Management/Department of Energy Office of Technology Development, p. 11.

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95-9   Beljin, M.S., and Losonsky, G., 1995, *Horizontal wells in environmental geology*, Environmental Geosciences, vol. 2, no. 1, pp. 54-59.

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97-2 Losonsky, G., 1997, *Horizontal well case studies*, Ground Water Institute Seminar in Directional Environmental Drilling, National Ground Water Association 49th Annual National Convention and Exposition, Las Vegas, Nevada, September 6, 1997.

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97-4 Losonsky, G., and Bardsley, D.S., 1997, *Horizontal wells offer advantages in environmental remediation*, Trenchless Technology, November 1997, pp. 37-39.

97-5 Losonsky, G., 1997, Comparing horizontal ground-water extraction well efficiencies at hazardous waste sites: Implications for well planning and development, American Institute of Professional Geologists 34th Annual National Meeting, Houston, Texas, October 10, 1997.

98-1 Tuta, Z.H., Losonsky, G., Jin, M., Londergan, J., and Shotts, D., 1998, *A partitioning tracer test to quantify residual DNAPL in heterogeneous sediments*, First International Conference on Remediation of Chlorinated and Recalcitrant Compounds, Monterey, California, May 18-21, 1998.

98-2 Losonsky, G., Tuta, Z., and Hecox, G.R., 1998, *Results of a pilot test of surfactant flushing and partitioning tracer technologies for DNAPL remediation*, presented at the University Consortium for Solvents-In-Groundwater Research, October 1998, Portland, Oregon, and at Florida Remediation Conference, Orlando, Florida, November 10-11, 1998.

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00-1   Losonsky, G., Moran, J., and Chheda, P., 2000, *Potassium permanganate injection in heterogeneous alluvium—a remediation pilot study,* The Second International Conference on Remediation of Chlorinated and Recalcitrant Compounds, Battelle, Monterey, California, May 22-25, 2000.

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ADDENDUM TO C-K &ASSOCIATES' TECHNICAL REPORT OF NOVEMBER 16, 2016:

EVALUATION OF PREDICTED DRAWDOWN AND CONSOLIDATION SETTLEMENT RESULTING FROM PROPOSED NOPS PUMPING

JUNE 28, 2017

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Evaluation of Predicted Drawdown and Consolidation Settlement Resulting From Proposed NOPS Pumping. George Losonsky, PhD, PG, June 25, 2017.

Introduction

This report was prepared as an Addendum to the C-K Associates' Technical Report – Evaluation of Groundwater Withdrawal and Air Quality dated November, 16 2016 (C-K Technical Report). The C-K Technical Report describes how subsidence is caused by consolidation of sediments, and how primary consolidation is controlled by natural processes while a combination of natural and man-made processes, including groundwater withdrawal, can cause secondary consolidation. The C-K Technical Report compares historical pumping rates in the Gonzales-New Orleans aquifer with pumping rates for the Combustion Turbine (CT) unit originally proposed by Entergy New Orleans, Inc. ("ENO") for the New Orleans Power Station (NOPS). This Addendum addresses an important change in ENO's proposed plan. ENO is presently considering the use of seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine (RICE") Generator sets (Alternative Peaker) as an alternative to the previously proposed CT unit. The Alternative Peaker significantly reduces the required groundwater usage rate. This Addendum utilizes drawdown calculations and consolidation settlement calculations to more accurately assess the potential impact of groundwater withdrawal on subsidence for both the CT unit and the Alternative Peaker. [1]

The C-K Technical Report used the proposed maximum required pumping rate for the CT unit, 96 gallons per minute (gpm), to evaluate NOPS's potential impact on subsidence. The C-K Technical Report noted that this rate, which is an order of magnitude less than historical pumping rates in the Gonzalez-New Orleans aquifer,[2] would create a drawdown level within the range of natural water level variations. Based on engineering estimates provided by the equipment vendor and EPC contractor, the Alternative Peaker will require a reduced pumping rate of 3.9 gpm. The anticipated pumping rate for the Alternative Peaker is less than one tenth of the pumping rate for the CT, and two orders of magnitude less than historical pumping rates. When compared to the original CT unit proposed flow of 96 gpm, Alternative Peaker usage rate will result in a groundwater use reduction of 95% and, when compared the deactivated Michoud units discussed in the C-K Technical Report, a 99.9% groundwater use reduction.

Based on this information, and the calculations described herein, it is reasonable and accurate to conclude that:

1) **The groundwater withdrawal associated with the proposed CT unit will not exacerbate subsidence or cause damage to infrastructure in New Orleans East.**

2) **The groundwater withdrawal associated with the proposed RICE units will not exacerbate subsidence or cause damage to infrastructure in New Orleans East.**

Drawdown Calculations

Consolidation settlement due to groundwater withdrawal can, under certain conditions, lead to subsidence. Louisiana aquifer systems comprise alternating sand aquifer units and intervening clay aquitards. Clay aquitards are an important part of the aquifer system. Slow but persistent leakage of groundwater vertically through

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[1] This Technical Addendum does not address changes associated with air quality as that will be addressed by other witnesses.

[2] *See* C-K Technical Report at pg. 11.

Evaluation of Predicted Drawdown and Consolidation Settlement Resulting From Proposed NOPS Pumping. George Losonsky, PhD, PG, June 25, 2017.

aquitards influences changes in hydraulic pressure in aquifers below or above the clay in response to the operation of water wells screened in the aquifer. Aquitards also have an important role in consolidation settlement, which can occur in both sandy aquifers and the clay aquitards, and which is influenced by water pressure in both the aquifers and aquitards.

Hydrogeologists and engineers designing groundwater withdrawal wells have been successfully using analytical solutions to predict the hydraulics of aquifer response to pumping since the 1930's, when Charles V. Theis applied the proven physical principles of heat transfer to solve the basic equation of groundwater flow to a well in radial coordinates (Jacob, 1950; Freeze and Cherry, 1979):

$$\frac{\partial^2 h}{\partial r^2} + \frac{1}{r}\frac{\partial h}{\partial r} = \frac{S}{T}\frac{\partial h}{\partial t}$$

(Equation 1)

In Equation 1, r is the distance from the well, h is hydraulic head, S is the non-dimensional storage coefficient of the aquifer, t is time, and T is the transmissivity of the aquifer which equals the product of the hydraulic conductivity (in units of distance per time) and the aquifer thickness.

Theis Solution for Drawdown

Using assumptions typical of analytical solutions that focus the equation on the fundamental aspects of the process and make the solution universally applicable by eliminating unnecessarily complicating details, Theis derived an equation for drawdown in and around a groundwater withdrawal well (Theis, 1935):

$$Theis\ Drawdown(r,S,T,t) = \frac{-Q}{4\pi T}\int_{u(r,S,T,t)}^{\infty}\frac{e^{-u}}{u}\,du$$

(Equation 2a)

where u is

$$u(r,S,T,t) = \frac{r^2}{4\left(\frac{T}{S}\right)t}$$

(Equation 2b)

The integral in Equation 2a is known as the Theis well function, and more detailed analytical solutions for drawdown use a more elaborate well function to reflect specific conditions.

To apply the Theis solution for drawdown to the New Orleans-Gonzalez aquifer beneath the New Orleans East area, we use 14,300 square feet per day for transmissivity, and 0.0001 as the storage coefficient. To simulate the proposed groundwater withdrawal wells at NOPS, the well is assumed to have a 100-foot long screen across the New Orleans-Gonzalez aquifer. If the well were to operate 24 hours a day, for 365 days a year,[3] at a pumping

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[3] It should be noted that neither proposed unit is expected to operate at this level of frequency. However, the assumption used herein presents the most conservative analysis possible by assuming maximum possible operation.

Evaluation of Predicted Drawdown and Consolidation Settlement Resulting From Proposed NOPS Pumping. George Losonsky, PhD, PG, June 25, 2017.

rate of 96 gallons per minute for 10 years[4], the Theis solution (Equation 2) predicts drawdown of about two feet at a distance 5 feet away from the well, 1.9 feet at a distance 100 feet away, 1.7 feet at a distance 250 feet away, and 1 foot at a distance 10,000 feet away from the pumping well. The red curve in **Figure 1** is a plot of drawdown as it changes with distance away from the well pumping 96 gallons per minute. For the proposed NOPS flow rate of 3.9 gallons per minute[5], the Theis solution predicts drawdown of about 0.08 foot within 100 feet of the well, 0.07 foot 250 feet away, and 0.05 foot at a distance 10,000 feet away from the pumping well. The red curve in **Figure 2** is a plot of drawdown as it changes with distance away from the well pumping 3.9 gallons per minute, calculated using the Theis solution.

Cooper-Jacob Approximation of Theis Solution

A commonly used approximation of the Theis equation eliminates the need to perform the integration in Equation 2, and was developed by Hilton H. Cooper and Charles E. Jacob (Cooper and Jacob, 1946):

$$CooperJacob\ Drawdown(r, S, T, t) = \frac{-Q}{4\pi T}\left(-0.5772 - \ln\left(\frac{r^2 S}{4Tt}\right)\right)$$

(Equation 3)

The dashed black curve seen superimposed on the red curve for the Theis solution in **Figure 1** is a drawdown plot derived by applying the Cooper-Jacob approximation of drawdown to the New Orleans-Gonzalez aquifer using the same parameters as above for the Theis solution and assuming a groundwater withdrawal rate of 96 gallons per minute. The Cooper Jacob approximation plot is virtually identical to the Theis solution plot for the 10-year timeframe and for the distance up to 10,000 feet away from the pumping well. The two solutions would diverge at shorter timeframes and at greater distances from the well. The dashed black curve in **Figure 2**, also superimposed on the red Theis solution curve, is plot of drawdown as it changes with distance away from the well pumping 3.9 gallons per minute, calculated using the Cooper-Jacob approximation.

Hantush and Jacob Leaky Aquifer Solution

The Theis Solution and Cooper-Jacob solutions both assume that the aquifer has uniform thickness, is confined, and non-leaky, which means that it receives no water from formations lying above and below the aquifer. The New Orleans-Gonzalez aquifer is part of the Southern Hills aquifer system of southeastern Louisiana, in which the clay aquitards separating the aquifers slow down but do not arrest the movement of water downward or upward into an individual aquifer (Buono, 1983; Morgan, 1963). The New Orleans-Gonzalez aquifer is no exception to this hydraulic connectivity, or leakance, and it is therefore appropriate to analyze the New Orleans-Gonzalez aquifer as a leaky aquifer (Freeze and Cherry, 1979).

Building on the principals of the Theis solution, Mahdi S. Hantush and Charles E. Jacob used an expanded well function that reflects the clay aquitard thickness, b_{aqt}, and the hydraulic conductivity of the clay aquitard, K_{aqt}, in their solution for drawdown in and around a groundwater withdrawal well in a leaky aquifer:

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[4] The 10 year timeframe is standard input for Theis, Cooper-Jacob, Hantush-Jacob or similar drawdown solution applied to a confined sandy aquifer. A confined aquifer will reach virtual steady-state long before 10 years, and drawdown will be essentially unchanged after about 5 years or less.

[5] This rate was also assumed for operation of 24 hours a day, 365 days per year for 10 years to provide the most conservative analysis possible.

Evaluation of Predicted Drawdown and Consolidation Settlement Resulting From Proposed NOPS Pumping. George Losonsky, PhD, PG, June 25, 2017.

$$HantushLeaky\ Drawdown(r, S, T, t, B) = \frac{-Q}{4\pi T} \int_{u(r,S,T,t)}^{\infty} \frac{e^{(-u\frac{r^2}{4B^2u})}}{u} du$$

<div align="right">[Equation 4a]</div>

where u is defined identically as in Equation 2b, for the Theis solution, and

$$B = \sqrt{T\frac{b_{aqt}}{K_{aqt}}}$$

<div align="right">[Equation 4b]</div>

The vertical hydraulic conductivity of clay aquitards in southern and southeastern Louisiana falls within the normal range for similar deposits around the world, typically between 0.15 and 0.003 feet per day. The solid blue curve in **Figure 1** is a plot of drawdown predicted by Equation 4a as it changes with distance away from the well pumping 96 gallons per minute, assuming the vertical hydraulic conductivity of the overlying clay aquitard is 0.15 feet per day, and the other parameters are the same in the previous calculations using the Theis solution and the Cooper-Jacob approximation. The 10-year timeframe of the drawdown calculation is especially conservative for this calculation. The Hantush and Jacob leaky confined aquifer solution predicts drawdown of approximately 0.8 foot within 100 feet of the well, 0.6 foot 250 feet away, and less than 0.02 foot at a distance 10,000 feet away from the pumping well. The dashed blue line in **Figure 1** represents the same calculation for the low end vertical hydraulic conductivity of the clay aquitard, 0.003 foot per day. Drawdown with the low-end leakance assumption is approximately 1.2 feet within 100 feet of the pumping well, 1.0 foot 250 feet away, and 0.27 foot at a distance 10,000 feet away. The solid blue curve in **Figure 2** is a plot of drawdown as it changes with distance away from the well pumping 3.9 gallons per minute, calculated using the Hantush and Jacob leaky confined aquifer solution assuming the vertical hydraulic conductivity of the overlying clay aquitard is 0.15 feet per day. Drawdown is approximately 0.03 foot within 100 feet of the well, 0.02 foot 250 feet away, and at a distance 10,000 feet away from the pumping well the drawdown is not measurable by normal methods. The farthest detectable drawdown, 0.005 foot, is predicted to develop approximately 3500 feet away from the well. The dashed blue line in **Figure 2** represents drawdown with vertical hydraulic conductivity of the clay aquitard at the low end, 0.003 foot per day. The low leakance drawdown is approximately 0.05 foot per day within 100 feet of the well, 0.04 foot 250 feet away, and 0.01 foot per day at a distance 10,000 feet away.

Consolidation Settlement Calculations

Consolidation settlement calculations for soils are rooted in the concept of effective stress which refers to the grain-to-grain contact stress and was defined by Karl von Terzaghi (Terzaghi, 1925; Terzaghi and Peck, 1967). The effective stress σ_e varies with the change in hydraulic head h:

$$d\sigma_e = -\rho g\ dh$$

<div align="right">[Equation 5]</div>

Evaluation of Predicted Drawdown and Consolidation Settlement Resulting From Proposed NOPS Pumping. George Losonsky, PhD, PG, June 25, 2017.

where ρ is pore fluid density and g is gravitational acceleration. The compressibility α of a soil is defined in terms of the void ratio e which is the ratio of the volume of voids to the volume of solid grains (without the pores):

$$\alpha = \frac{-de/(1 + e_o)}{d\sigma_e}$$

[Equation 6]

where e_o is the initial void ratio before compression. If compressibility of the soil is known, a linear approximation of the compaction of an aquifer in response to declining hydraulic head (increasing drawdown) is (Freeze and Cherry, 1979):

$$db = -\alpha \, b \, \rho \, g \, dh$$

[Equation 7]

where b is the initial thickness of the aquifer. Based on Terzaghi's principle expressed in Equation (5), Wen-Jie Niu developed a solution for the total settlement in a sandy aquifer overlain by a clay layer due groundwater withdrawal from a well (Niu *et al.*, 2013):

$$Total \; Settlement = \int_0^{D_c} db = \int_0^{D_c} C_c \frac{1}{1 + e_o(z)} \log \frac{\sigma_{eo} + \sigma_{zr}}{\sigma_{eo}} \, dz$$

[Equation 8]

where D_c is the thickness of the aquifer, $e_o(z)$ is the initial void ratio at depth z, σ_{zr} is the vertical stress in the aquifer at the well (where the radial cooridinate r equals 0), σ_{eo} is the initial effective stress at a point in the aquifer, and C_c is the compression index (Freeze and Cherry, 1979):

$$C_c = -\frac{de}{d(\log \sigma_e)}$$

[Equation 9]

Substituting an expression for σ_{zr} that is specifically derived for a groundwater withdrawal well in a confined aquifer and applying Terzaghi's principle expressed in Equation 5, Equation 8 becomes (Niu *et al.*, 2013):

$$Total \; Settlement$$

$$= \int_0^{D_c} C_c \frac{1}{1 + e_o(z)} \log \left[\left(D\rho_1 g + z\rho_2 g - (H_0 - D_c + z)\rho_w g \right. \right.$$

$$\left. \left. + \int_{r_w}^{R} \frac{3A}{z^2} \frac{r \ln\left(\frac{R}{r}\right)}{\left[1 + \left(\frac{r}{z}\right)^2\right]^{5/2}} \right) dr \left(\frac{1}{D\rho_1 g + z\rho_2 g - (H_0 - D_c + z)\rho_w} \right) \right] dz$$

[Equation 10]

6

where D is the thickness of the clay layer, ρ_1, ρ_2, and ρ_w are the densities of the overlying clay, the aquifer sand, and the pore water, respectively; H_0 is the static water elevation with respect to the base of the confined aquifer, R is the zone of influence of the well at a given flow rate Q, and A is:

$$A = \left(\frac{Q}{2\pi K D_c}\right)\rho_w g$$

[Equation 11]

where K is the hydraulic conductivity of the aquifer. Table 1 below summarizes calculated total possible settlement (in millimeters and in inches) for two or three values for each of the following parameters:

- Static water level measured from the base of the New Orleans-Gonzalez aquifer, H_0 (in feet)
- Compression index, C_c
- Void ratio, e_o
- Flow rate of the groundwater withdrawal well, Q (in gallons per minute)

These values represent the total settlement that might be expected as a result of groundwater withdrawal from the New Orleans-Gonzalez aquifer at the proposed flow rates for NOPS operation. The settlement would occur within the aquifer, in the depth range of 500 to 650 feet. The calculated amount of settlement is not repeatable with successive pumping events, and does not accumulate. The settlement can occur fairly rapidly after the onset of pumping and is not expected to be drawn out over years.

TABLE 1

H_0 (ft)	C_c	e_0	Settlement (millimeters)		Settlement (inches)	
			Q = 3.9 gpm	Q = 96 gpm	Q = 3.9 gpm	Q = 96 gpm
580	0.05	0.3	0.04	1.0	0.0016	0.037
580	0.05	0.8	0.03	0.7	0.0012	0.027
580	0.13	0.3	0.10	2.5	0.0039	0.097
580	0.13	0.8	0.07	1.8	0.0028	0.070
580	0.23	0.3	0.18	4.4	0.0071	0.171
580	0.23	0.8	0.13	3.1	0.0051	0.124
620	0.05	0.3	0.04	1.0	0.0016	0.040
620	0.05	0.8	0.03	0.7	0.0012	0.029
620	0.13	0.3	0.11	2.7	0.0043	0.105
620	0.13	0.8	0.08	1.9	0.0031	0.076
620	0.23	0.3	0.19	4.7	0.0075	0.185
620	0.23	0.8	0.14	3.4	0.0055	0.134

Evaluation of Predicted Drawdown and Consolidation Settlement Resulting From Proposed NOPS Pumping. George Losonsky, PhD, PG, June 25, 2017.

Settlement values range from 0.001 inch to 0.185 inch; such calculated settlements, if they occurred, would occur at depths exceeding 500 feet from the ground surface. Calculated settlement increases with the compression index and to a lesser extent with decreasing initial void ratio. The three values used for compression index represent a range from the relatively low compression index of a clean beach sand (0.05) to the almost two orders of magnitude higher compression index of clay (0.23). The lower of the two void ratios used (0.3) is equivalent to 23 percent porosity and represents sand, and the higher void ratio (0.8) is equivalent to 45 percent porosity, which is typical of clay-rich soils.

Predicted total settlement is less than one fifth of an inch regardless of the soil parameters, and using the compression index corresponding to the soil type of the New Orleans-Gonzalez aquifer the calculated settlement is 0.04 inch (1 mm) or less if the flow rate is 96 gpm, and less than 0.002 inch (0.04 mm) at the proposed flow rate of 3.9 gpm.

Conclusion

Drawdown and consolidation settlement analyses for the proposed NOPS groundwater withdrawal support the conclusions of the C-K Technical Report concerning subsidence and differential settlement. The analyses show that operating the proposed NOPS units may cause limited settlement within the aquifer at depths exceeding 500 feet. Furthermore, since the proposed pumping rates do not exceed historical pumping rates, the operation of the wells is expected to produce no additional settlement. Finally, the calculations assume continuous pumping, 24 hours a day and 365 days a year, which adds up to significantly higher pumping volumes than is expected under normal operating conditions. Therefore, the calculated settlement values are conservative estimates. If any settlement were to occur it would be too small and too deep to cause damage to buildings, infrastructure, and flood protection structures at the ground surface. Drawdown created by either of the two pumping rates considered is insufficient to reverse regional trends of water level rise. Neither differential settlement nor regional subsidence will be exacerbated by the operation of the proposed NOPS wells.

Evaluation of Predicted Drawdown and Consolidation Settlement Resulting From Proposed NOPS Pumping. George Losonsky, PhD, PG, June 25, 2017.

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Figures

FIGURE 1
Drawdown at 10 years (96 gallons per minute)

Evaluation of Predicted Drawdown and Consolidation Settlement Resulting From Proposed NOPS Pumping. George Losonsky, PhD, PG, June 25, 2017.

FIGURE 2
Drawdown at 10 years (3.9 gallons per minute)

Evaluation of Predicted Drawdown and Consolidation Settlement Resulting From Proposed NOPS Pumping. George Losonsky, PhD, PG, June 25, 2017.

INFORMATION SUBMITTAL

Evaluation of Proposed Groundwater Withdrawals and Subsidence Entergy New Orleans Power Station

Entergy
New Orleans, Orleans Parish, Louisiana

MVN-2015-2311

Project No. 155004

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June 16, 2017

*Table of Contents*_____

List of Figures _____

List of Appendices _____

N:\Client\Entergy\NOPS_Michoud\Peaking Engine Units (2017)\Proposed GW Withdrawals\Final Submittal\Michoud Information Submittal Proposed
Groundwater Withdrawal Revised FINAL 61617.docx

List of Acronyms _____

bgs	Below ground surface
ENOI	Entergy New Orleans Inc.
ft/day	Feet per day
ft2/day	Feet squared per day
gpd	Gallons per day
gpd/ft	Gallons per day per foot
gpm	Gallons per minute
gpm/ft	Gallons per minute per foot
MCL	Maximum Contaminant Level
MGD	Million gallons per day
mg/l	Milligrams per liter
mm	Millimeters
mm/yr	Millimeters per year
MW	Megawatts
m2/Newton	Meter squared per Newton
NOPS	New Orleans Power Station
RICE	Reciprocating Internal Combustion Engine
S	Storage Coefficient
SCGT	Simple Cycle Gas Turbine
T	Transmissivity
USACE	U.S. Army Corps of Engineers

1.0   Introduction

Entergy New Orleans, Inc. (ENOI) a subsidiary of the New Orleans based Entergy Corporation is proposing to construct the New Orleans Power Station (NOPS). The NOPS will be located within the boundary of the property on which ENOI's existing Electric Generating Plant is located in the New Orleans East area. **Figure 1** shows the site location.

The Michoud Plant was operated starting in the 1950s with three units with a generating capacity of 805 megawatts (MW). Units 1, 2, and 3 were deactivated in 2016. During its operation, the Michoud Plant used groundwater from the Gonzales-New Orleans aquifer and surface water. The groundwater usage is reported to have ranged from 2.99 to 20.7 million gallons per day (MGD) during the operation of the Michoud Plant. The proposed NOPS facility will use either (i) a Simple Cycle Gas Turbine (SCGT) generator with an output capacity of 246 MW[1] or (ii) Reciprocating Internal Combustion Engine (RICE) generators with an output of 128 MW.

For both of these generating alternatives, the makeup water for process water, service water, and fire protection may be derived from the existing water-supply well system that would withdraw groundwater from the Gonzales-New Orleans aquifer (also known as the 700-Foot Sand). The SCGT alternative is expected to need a maximum groundwater supply of up to 96 gallons per minute (gpm), which is approximately 138,000 gallons per day (gpd) or 0.138 MGD. The RICE alternative is expected to need a groundwater supply of 3.9 gpm (0.005 MGD). The proposed groundwater usage for these alternatives is only a small percentage of the historical use of groundwater by the Michoud Plant during its operation.

The New Orleans District, U.S. Army Corps of Engineers (USACE) recently met with citizens of the New Orleans East area who cited questions about potential land subsidence associated with the proposed groundwater withdrawals for the NOPS generating facility. ENOI has engaged qualified outside experts to carefully evaluate the geologic and hydrogeologic conditions of the Michoud area in reference to the potential for any additional subsidence to address the citizens' questions. ENOI presented a summary of this evaluation in a meeting at the USACE New Orleans District on May 11, 2017 at the request of the New Orleans District. Our detailed evaluation is presented in this document, which demonstrates the following positions:

- The proposed NOPS groundwater withdrawal will be significantly lower than the historical pumping of the Gonzales-New Orleans aquifer at Michoud and will have

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[1] According to the Application filed with the Council for the City of New Orleans, ENOI estimates that the SCGT will provide approximately 226 MW (nominal) of summer generating capacity. The actual maximum output of the unit will depend on the following variable factors and conditions: ambient air temperature, relative humidity, Btu content of natural gas delivered at the unit, and number of operating hours since the last maintenance interval.

groundwater level drawdowns in the range of 1 to 2.1 feet within a 2-mile radius of the well.

- The proposed NOPS groundwater withdrawals will be too small to contribute to any subsidence in the Michoud area.

- Recent research on subsidence in the Michoud area shows conflicting and inconsistent results, and can be explained by subsidence being related to compaction of shallow organic-rich sediments such as peat and settlement associated with large structures.

Section 2.0 of this document provides an evaluation of any possible subsidence at the NOPS facility that could be related to the proposed groundwater withdrawals. This includes a summary of the geology and hydrogeologic conditions of the Gonzales-New Orleans aquifer and the historical groundwater withdrawals and groundwater level drawdowns of the Gonzales-New Orleans aquifer. This section also evaluates any possible subsidence associated with the proposed groundwater withdrawals. Section 2.0 also includes a discussion of recent subsidence measurements and research articles addressing subsidence in the Michoud area. Section 3.0 of this document presents the conclusions of this evaluation concerning the conditions of the Gonzales-New Orleans aquifer at Michoud and the unlikelihood that subsidence will be induced by the proposed groundwater withdrawals.

2.0   Evaluation of Subsidence at Michoud

Subsidence is the sinking or settlement of the land surface, due to any of several processes (Poland et al., 1972). Subsidence can be uniform or can be spatially irregular. Spatially uniform subsidence is referred to as regional subsidence. Spatially irregular or localized subsidence is referred to as differential subsidence or differential settlement (Holzer, 1991; Galloway et al., 1999).

Subsidence can be caused by a diverse set of natural processes and human activities (National Research Council, 1991; Galloway et al., 1999; and Allison et al., 2016). The principal subsidence processes affecting New Orleans and the surrounding area include (Allison et al., 2016):

- Tectonic subsidence of the crust (lithosphere)
- Sediment loading from regional sediment accumulation
- Isostatic adjustment of the crust to Quaternary glaciation and sea level changes
- Sediment compaction (consolidation) on regional and local scales
- Fluid withdrawal from the subsurface

The subsidence processes related to tectonics, regional sediment loading, and isostatic adjustment give rise to regional-scale subsidence, but can also show local variations causing differential subsidence adjacent to growth faults.

Sediment compaction or consolidation is the decrease in thickness of a layer of sediment as a result of application of a sustained load to the sediment. Compaction is a natural process and typically causes broad regional subsidence as sedimentation occurs. Compaction can be enhanced by the application of additional loads such as buildings or fill material. In the New Orleans area, compaction of shallow organic-rich soils is an important driver of subsidence. Drainage of organic soils such as peat and backswamp clay deposits induces biological oxidation, desiccation, and collapse resulting in compaction and subsidence of the land surface. Compaction of organic-rich soils can be highly variable and localized resulting in differential subsidence.   In the New Orleans area, peat deposits have the greatest potential for subsidence when drained because of their high water content and ease of drainage (Snowden et al., 1980; Kolb and Saucier, 1982). Differential subsidence related to drainage of organic-rich soils has been considered the greatest subsidence problem in New Orleans because of the widespread damage to roads, utilities, and structures caused by this process (Snowden et al., 1980).

Withdrawal of groundwater or oil and gas from aquifers or reservoirs in the subsurface can contribute to subsidence. The decrease of the fluid pressure because of pumping causes more of the overburden load to be supported by the sediment grains. This increase of the effective stress induces compaction of the aquifer or reservoir. The magnitude of subsidence induced by fluid

withdrawal is related to the decrease of the fluid pressure. In groundwater aquifers, the largest subsidence will occur in the central portion of the cone of depression of the potentiometric surface of the pumped aquifer and will decrease radially outward. In the greater New Orleans area, the principal fluid withdrawal has been historical pumping of groundwater from the Gonzales-New Orleans aquifer for industrial water supply. Oil and gas production has occurred in the area surrounding New Orleans, but has been minor in the city and adjacent suburbs. The objective of this section is to describe the geologic and hydrogeologic conditions that are relevant to the potential for subsidence to occur in the Michoud area as a result of the proposed groundwater pumping at the NOPS facility.

2.1   Site Geology and Hydrogeology

The New Orleans area is underlain by Pleistocene and Holocene coastal-plain deposits of the Mississippi River deltaic plain (Kolb, 1962; Kolb et al., 1975; Dunbar et al., 1994, Saucier, 1994). These deposits form the upper portion of the Gulf Coast sedimentary basin in which sedimentary deposition has occurred between the Jurassic Period and the present day. In the area of the NOPS facility near Michoud, the Holocene deposits range from 50 to 60 feet thick (Kolb et al., 1975; Dunbar et al., 1994; Saucier, 1994) and are underlain by undifferentiated alluvial and coastal plain deposits of the Pleistocene-age Prairie Formation (Prairie Complex).

The Holocene section at the NOPS site from the ground surface downwards consists of approximately 10 feet of natural levee and swamp deposits (silt and clay) underlain by approximately 40 feet of intradelta sand and silt and interdistributary clay. The intradelta deposits were deposited between 3,000 and 1,000 years before present by the Bayou Sauvage Distributary, which is located on the north side of the facility. The main channel of the Mississippi River was located along the Bayou Sauvage Distributary during that time and discharged to the east in the St. Bernard delta lobe of the Mississippi River delta. To the north and east of the NOPS site, the upper part of the Holocene section includes up to 10 to 15 feet of marsh deposits of the St. Bernard lobe of the Mississippi River delta. The marsh deposits consist of dark gray and black watery ooze and very soft organic clay and peat with high moisture contents and low strengths (Kolb, 1962).

The Pleistocene Prairie Complex consists of undifferentiated alluvial and coastal plain deposits extending to depths of 200 to 250 feet (Kolb et al., 1975). The Prairie Complex ranges from 150 to 200 feet in thickness and consists of clay, silt, and sand deposited in alluvial environments. The top surface of the Pleistocene Prairie Complex forms a distinctive lithologic interface recognized by its contrast in color, soil consistency and strength, and water content (Kolb, 1962). The upper portion of the Pleistocene generally is tan, reddish brown, or brown in color as a result of its oxidation and weathering during exposure prior to the Holocene deposition. The overlying Holocene sediments typically are dark gray in color and have high water content and lower strength.

The Pleistocene sediments extend to depths of approximately 1,500 feet below ground surface (bgs) in the New Orleans East area (DuBar et al., 1991; Jones et al., 1996). The Pleistocene section includes sand zones identified as the Gramercy aquifer (200-Foot Sand), Norco aquifer (400-Foot Sand), Gonzales-New Orleans aquifer (700-Foot Sand), and the 1,200-Foot Sand (Tomaszewski, 2003; Prakken, 2009). These sand zones have been utilized as aquifers for groundwater supply in parts of the New Orleans area and adjacent areas.

Geologic cross section D-D' of Prakken (2009) and the north-south cross section labeled North-South intersect at the NOPS site and depict the stratigraphy of the Pleistocene aquifer sand units. **Figure 2** shows the locations of the geologic cross sections. **Figure 3** presents the west-east cross section D-D' (Prakken, 2009). The Gramercy aquifer and the Norco aquifer are thin or missing along this line of section and occur in the western portion of Orleans Parish and in Jefferson Parish (Prakken, 2009). The Gonzales-New Orleans aquifer is continuous along section D-D' and the top of the aquifer occurs at elevations ranging from -400 to -590 feet relative to the National Geodetic Vertical Datum of 1929. The aquifer dips at a low angle from east to west. The thickness of the Gonzales-New Orleans aquifer ranges from approximately 70 feet to 170 feet. The west-east cross section shows that the upper sand unit of the Gonzales-New Orleans aquifer is discontinuous and occurs intermittently along the cross section with thicknesses of up to 20 to 50 feet. The 1,200-Foot Sand is shown as discontinuous sand bodies occurring at elevations of -600 to -850 feet elevation.

Figure 4 shows a north-south cross section prepared for this report from well logs of water wells and petroleum test wells and from geologic data from Cardwell et al., (1967) and Prakken (2009). This section shows that the sand units dip to the southeast and south. The Gramercy and Norco aquifers also are thin and discontinuous or missing along this line of section. The Gonzales-New Orleans aquifer is continuous along the north-south cross section from the Slidell, Louisiana area to south of the proposed NOPS location. The top of the Gonzales-New Orleans aquifer ranges from an elevation of approximately -200 feet at the north end in the Slidell area to approximately -530 feet at the south end of the cross section south of the Intracoastal Waterway. The dip of the top of the Gonzales-New Orleans aquifer ranges from 15 to 20 feet per mile along the north-south cross section. In the Slidell area and elsewhere along the north shore of Lake Pontchartrain, the aquifer occurring between elevations -200 and -400 feet is known as the Shallow aquifer (Nyman and Fayard, 1978). The north-south cross section shows that the Shallow aquifer is the updip equivalent of the Gonzales-New Orleans aquifer and is stratigraphically continuous with the Gonzales-New Orleans aquifer. The thickness of the Gonzales-New Orleans aquifer ranges from 145 to over 200 feet along the north-south cross section. In the area near Michoud and the proposed NOPS, the thickness of the Gonzales-New Orleans aquifer ranges from 155 to 170 feet in agreement with the aquifer thickness map of Prakken (2009). The north-south cross section also shows that the upper sand unit of the Gonzales-New Orleans aquifer occurs as a continuous

sand unit from the proposed NOPS northward. The upper sand unit is 20 to 50 feet thick and is separated from the Gonzales-New Orleans aquifer by 25 feet to 100 feet of clay. The north-south cross section shows that the 1,200-Foot Sand occurs at elevations of -650 to -820 feet elevation and is continuous.

The Gonzales-New Orleans aquifer consists of fine to medium-grained sand (Rollo, 1966; Dial, 1983). Grain-size analyses of sand samples collected during the installation of Michoud water well #1 (Or-124) and water well #2 (Or-125) show that the proportions of fine and medium sand are approximately equal except in the basal portion, which is predominantly finer grained consisting primarily of fine sand. The electric logs of water wells and petroleum test wells in the area indicate that the basal portion of the Gonzales-New Orleans aquifer is finer grained than the middle and upper portions of the aquifer.

The hydraulic properties of the Gonzales-New Orleans aquifer have been assessed from pumping tests (Rollo, 1966; Dial, 1983; Dial and Sumner, 1989) and the hydraulic conductivity was estimated to range from 80 to 120 feet per day (ft/day). The transmissivity was estimated to range from 12,000 to 24,000 feet squared per day (ft^2/day), which is equivalent to approximately 90,000 to 180,000 gallons per day per foot (gpd/ft). The storage coefficient was estimated to range from 0.0001 to 0.001 (dimensionless). The specific capacities of water wells in the Gonzales-New Orleans aquifer have been reported to range from 8 to 67 gallons per minute per foot (gpm/ft) (Eddards et al., 1956). At the Michoud Plant, the specific capacities of the water wells in the Gonzales-New Orleans aquifer have ranged from 24.6 to 49.7 gpm/ft and the average specific capacity was estimated to be 37.5 gpm/ft. These values of specific capacities are high and indicate that the water wells have high efficiency and productivity.

The recharge area of the Gonzales-New Orleans aquifer is north of Lake Pontchartrain in broad areas of southern St. Tammany and Tangipahoa Parishes and southern Livingston Parish (Walters, 1995). The Gonzales-New Orleans aquifer is stratigraphically continuous with the Shallow aquifer north of Lake Pontchartrain and groundwater levels in the Shallow aquifer of the Slidell area have been below sea level (Nyman and Fayard, 1978) in areas with limited groundwater pumpage. Therefore, the Gonzales-New Orleans aquifer is in hydrologic continuity with the recharge area. The groundwater average linear velocities in the cone of depression of the Gonzales-New Orleans aquifer were estimated to range from 100 to 350 feet per year (Walters, 1995). At these groundwater flow rates, the travel time from the north side of Lake Pontchartrain to the eastern part of New Orleans would be on the order of 150 to 500 years.

2.2   *Groundwater Withdrawals and Drawdowns, Gonzales-New Orleans Aquifer*

The Gonzales-New Orleans aquifer has been the principal source of groundwater supply for industry in the greater New Orleans area. Development of the aquifer started in the late 1800s (Rollo, 1966) and included wells used for public water supply. In 1903, the groundwater levels in

the Gonzales-New Orleans aquifer were near the ground surface (Eddards et al., 1956) and the total groundwater pumpage from the aquifer was estimated to be approximately 5 MGD (Rollo, 1966). The groundwater withdrawal from the Gonzales-New Orleans aquifer increased to approximately 23 MGD in Orleans Parish by 1953 and the groundwater levels had declined to 94 feet bgs by 1954 in the areas of greatest pumping (Eddards et al., 1956). During the time period from the 1950s through the present day, the groundwater withdrawals from the Gonzales-New Orleans aquifer have been used by industry. Groundwater from the Gonzales-New Orleans aquifer has not been considered satisfactory for public water supply since the early 1900s because of its yellow color. The yellow color is of organic origin from leaching of natural organic matter and gives the water a displeasing appearance (Rollo, 1966). The color of the Gonzales-New Orleans aquifer groundwater generally exceeds 100 platinum-cobalt color units in Orleans Parish and is greater than 300 platinum-cobalt color units in some wells (Dial, 1983). In comparison, the U.S. Environmental Protection Agency Secondary Maximum Contaminant Level (MCL) standard for color is 15 platinum-cobalt color units. The principal uses of the water by industry have been cooling water for manufacturing plants and electrical generation and cooling water for air conditioning of commercial buildings.

In the period from the 1950s through 1980s, the major centers of groundwater withdrawal from the Gonzales-New Orleans aquifer were in downtown New Orleans, the Industrial Canal area near Lake Pontchartrain, and the Michoud area (Michoud Plant and other industry). The total groundwater withdrawals in Orleans Parish during this time interval were reported by the U.S. Geological Survey to range from 35 to 43 MGD (Snider and Forbes, 1961; Bieber and Forbes, 1966; Dial, 1970; Cardwell and Walter, 1979; Walter, 1982; Lurry, 1987). **Figure 5** shows the potentiometric surface of the Gonzales-New Orleans aquifer in September 1963 (Rollo, 1966). The distribution of the cone of depression of the potentiometric surface indicates the effects of the groundwater withdrawals on the groundwater levels. The lowest groundwater levels (elevations of -120 to -130 feet) occurred in the center of the cone of depression centered on the downtown area and the Industrial Canal area. The groundwater withdrawal at the Michoud area generated a small secondary cone of depression with groundwater levels at an elevation of approximately -100 feet in the center of the cone of depression. In 1963, the groundwater withdrawal at the Michoud Plant was estimated to be approximately 6 MGD (Rollo, 1966) and was a small percentage of the total groundwater withdrawal in Orleans Parish.

In the 1990s the groundwater withdrawals from the Gonzales-New Orleans aquifer had decreased significantly because of plant closings in the downtown area and decrease of groundwater use for commercial air conditioning (Dial, 1983; Walters, 1995). In the 1990 to 1995 time interval, the total groundwater withdrawals in Orleans Parish were reported by the U.S. Geological Survey to range from approximately 13 to 22 MGD (Lovelace, 1991; Lovelace and Johnson, 1996). **Figure 6** shows the potentiometric surface of the Gonzales-New Orleans aquifer in the Spring of 1993

(Walters, 1995). The configuration of the cone of depression shifted to being centered on the Industrial Canal area. The groundwater levels rose approximately 10 to 15 feet since the late 1980s in the downtown area as a result of decreased groundwater pumpage in that area (Walters, 1995). The 1993 potentiometric map shows that the cone of depression was elongated to the east toward the industrial groundwater pumping in the Michoud area.

The groundwater withdrawals from the Gonzales-New Orleans aquifer decreased further by 2000 because of less usage in the Industrial Canal area. The total groundwater withdrawals in Orleans Parish during the 2000 to 2010 time interval were reported by the U.S. Geological Survey to range from approximately 5 to 13 MGD (Sargent, 2002; Sargent, 2007; Sargent, 2012). **Figure 7** shows the potentiometric surface of the Gonzales-New Orleans aquifer in the Spring of 2008 (Prakken, 2009). The configuration of the cone of depression had shifted farther eastward to be centered on the Michoud area. The groundwater levels in the downtown area and Industrial Canal area had recovered by an additional 40 to 50 feet from the groundwater levels shown by the 1993 potentiometric map as a result of the decreased groundwater pumpage in those areas. The groundwater levels in the center of the cone of depression in the Michoud area had elevations that ranged from -110 to -120 feet elevation. Prakken (2009) estimated the groundwater pumping at Michoud in 2007 to include 9.7 MGD at the Michoud Plant and 1.9 MGD at industry located on the east side of the Michoud Canal.

The groundwater pumping at the Michoud Plant was estimated by ENOI to be approximately 10.87 MGD from 2010 until the deactivation in 2016. The groundwater pumping subsequently was decreased significantly after deactivation of the facility.

Groundwater levels in monitoring wells in the Gonzales-New Orleans aquifer show upward trends resulting from the significant decreases of groundwater withdrawals from the aquifer. **Figure 8** shows graphs of groundwater levels in observation well Or-206 located west of Michoud, observation well Or-203 located north of Michoud, and observation well Or-175 located to the east of Michoud. Wells Or-203 and Or-175 are located on the northeast and east sides of the cone of depression. Well Or-206 is located in the area that was the center of pumping from the Industrial Canal area and more recently (in 2008 as shown in **Figure 7**) was located in the western part of the cone of depression. The groundwater levels in these wells showed stabilization by the 1990s and strong upward recovery or rebound after 2000. The rapid rebound of groundwater levels is a result of the high hydraulic diffusivity (ratio of transmissivity to storage coefficient) of the Gonzales-New Orleans aquifer and the hydrologic continuity of the Gonzales-New Orleans aquifer with the region of higher hydraulic heads in the Shallow aquifer of the recharge area located north of Lake Pontchartrain.

The distribution of groundwater salinity in the Gonzales-New Orleans aquifer in 2008 is shown in **Figure 9** (Prakken, 2009). In this figure, fresh groundwater contains less than 250 milligrams per

liter (mg/l) of chloride. The Gonzales-New Orleans aquifer contains fresh groundwater to the north of the Mississippi River and the Intracoastal Waterway. The north-south geologic cross section (**Figure 4**) shows that fresh groundwater occurs in the Gonzales-New Orleans aquifer from the recharge area north of Lake Pontchartrain to the area north of the NOPS facility. The west east geologic cross section (**Figure 3**) shows that fresh groundwater occurs in the Gonzales-New Orleans aquifer west of the NOPS facility. Saline groundwater occurs in the aquifer at the NOPS facility and in the area to the east. The aquifer contains saline water to the south of the freshwater area. The interface between saline groundwater and fresh groundwater has occurred north of the NOPS site since the onset of groundwater use at the Michoud Plant. In 2008, the wells at the Michoud Plant had chloride concentrations of 458 to 559 mg/l and the total dissolved solids (TDS) have ranged from 685 to over 1,000 mg/l (Dial, 1983; Prakken, 2009). The Secondary MCL standard for chloride is 250 mg/l and for TDS is 500 mg/l so the groundwater at the NOPS site is not considered to be potable. In addition, the high color of the Gonzales-New Orleans aquifer groundwater exceeds the secondary MCL for color.

The locations of centers of groundwater withdrawals in areas at and south of the interface between fresh and saline groundwater has stabilized the position of the interface (Rollo, 1966) during the period of groundwater withdrawals since the late 1800s. Rollo (1966) recommended that the use of brackish and slightly saline groundwater by industry be encouraged as a means to limit potential encroachment of saline groundwater into the region of fresh groundwater in the Gonzales-New Orleans aquifer.

2.3   Estimated Subsidence from Proposed Groundwater Withdrawals

ENOI is evaluating two alternatives for electrical generation at the NOPS facility. For both of these generating alternatives, the makeup water for process water, service water, and fire protection may be derived from the existing water-supply well system in the Gonzales-New Orleans aquifer. The SCGT alternative is expected to need a groundwater supply of 96 gpm (0.138 MGD). The RICE generating alternative is expected to need a groundwater supply of 3.9 gpm (0.005 MGD). The proposed groundwater usage for these alternatives is significantly lower than the historical use of groundwater by the Michoud Plant during its operation.

The NOPS facility has seven water wells installed in the Gonzales-New Orleans aquifer including well #2, well #3, well #4, well #5, well #6, well #7, and well #8. **Figure 10** shows the locations of the water wells at the facility. The water wells can be pumped at rates ranging from approximately 1,200 gpm to over 2,200 gpm. **Appendix A** includes information on the ENOI Michoud Plant water wells. To supply the water volume needed on a daily basis by the NOPS facility, it is expected that one of two of the water wells would be used periodically to fill a water storage tank. ENOI is proposing to use well #5 and well #6 for the groundwater pumping, with one of the two wells serving as a redundancy to the other.

The drawdown of groundwater levels in the Gonzales-New Orleans aquifer that could be induced by pumping of the site water wells has been estimated with the modified non-equilibrium Cooper-Jacob equation for well drawdown (Driscoll, 1987). The drawdown, s, in feet is given by the following equation in dimensional form:

$$s = \frac{264Q}{T} \log \frac{0.3Tt}{r^2S}$$

where Q is the pumping rate in gpm, T is the aquifer transmissivity in units of gallons per day per foot (gpd/ft), log is the logarithm function to the base 10, t is time of pumping in days, r is the radial distance from the pumping point in feet, and S is the dimensionless storage coefficient. This equation will be referred to as the drawdown equation. This equation is a commonly-used modification of the well-known Theis drawdown equation and is appropriate for use when the well function W(u) can be approximated by the logarithm function. This occurs when the value of u:

$$u = \frac{1.87Sr^2}{Tt}$$

is less than 0.05. For the range of parameter values used in the estimation of drawdown in the site area, the values of u are less than 0.05 so that the drawdown equation is a valid approximation of the Theis drawdown equation.

Based on inspection of the drawdown equation, it can be seen that the drawdown will increase as the pumping rate is increased and as the transmissivity is decreased. The drawdown also will increase as the time duration of pumping is increased. The drawdown will decrease with increasing distance from the point of pumping. The drawdown also is related to the storage coefficient and will decrease if the storage coefficient is higher.

Use of the drawdown equation is one approach for estimating hydraulic impacts of groundwater pumping. For well-defined aquifers that have large areal extent, relatively uniform thickness, moderately uniform hydraulic properties, and that are bounded by well-defined aquitards, the use of the drawdown equation provides an effective and simple means for estimating conservative drawdown values or for calculating ranges of possible drawdown values. In contrast, use of a numerical model to evaluate groundwater-level drawdowns for the same aquifer setting would require more extensive data input to yield similar predictions and would require estimation of poorly-constrained input parameters to include leakage and recharge.

The drawdown distributions were calculated with the drawdown equation for the proposed pumping rates of 96 gpm and 3.9 gpm. Conservative values of the hydraulic properties of the Gonzales-New Orleans aquifer were assigned based on the NOPS site conditions and hydraulic properties data for the aquifer. The transmissivity value for the Gonzales-New Orleans aquifer

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was assigned as 14,300 ft^2/day (106,964 gpd/ft). The storage coefficient was assigned to be 0.0001 (dimensionless). The drawdown was calculated for a time duration of 10 years of pumping. The drawdown is predicted to stabilize prior to this time and to undergo minor increases after that time. For the pumping rate of 96 gpm (the highest proposed pumping rate), the estimated drawdown will range from 2.1 feet within 50 feet of the pumped well to 1.0 feet at a distance of 2 miles (10,560 feet). For the 3.9 gpm pumping rate, the drawdowns will range from 0.08 feet (approximately 1 inch) to less than 0.04 feet at distances of 1 to 2 miles.

Figure 11 shows the estimated drawdown distribution to a distance of 1 mile from the location of well #6 at the NOPS facility. The water-level drawdown will be imposed on the background groundwater levels. Because the Gonzales-New Orleans aquifer has been undergoing significant rebounding of water levels on the order of 30 to 50 feet since 2000, the groundwater levels in the Michoud area are expected to continue to rise. The recent rate of rise of groundwater levels is 1.5 to 2 feet per year. The ongoing recovery of groundwater levels in 1 year would exceed the drawdown caused by the proposed pumping. Therefore, the proposed pumping rates are too low to generate and maintain a significant cone of depression in the aquifer's groundwater levels.

As requested by the New Orleans District, USACE in the meeting of May 11, 2017, the profile of groundwater level drawdowns has been evaluated in the area of the Hurricane Protection Levee adjacent to the Intracoastal Waterway. **Figure 12** shows the topographic cross section between well #6 and the Hurricane Protection Levee on the southeast side of the NOPS site. The drawdowns generated by the 96 gpm pumping rate are shown on **Figure 12**. The drawdown distribution is close to uniform in the area less than 250 feet from the pumping well and ranges from 2.1 to 1.7 feet. In the pumped well, the drawdown will be approximately 2.2 to 2.6 feet based on the high specific capacities of the water wells (37.5 to 41.8 gpm/ft). For the alternative case of pumpage at 3.9 gpm, the drawdowns in the area from the well to a distance of 250 feet would be 0.08 feet (approximately 1 inch).

The estimated drawdowns for both alternatives of groundwater pumping rate are less than the groundwater level fluctuations in the Gonzales-New Orleans aquifer caused by variations in regional pumpage, tidal fluctuations, or the time-dependent effects of groundwater recharge north of Lake Pontchartrain. Review of the records of groundwater levels in observation wells located away from the centers of groundwater withdrawal in the Gonzales-New Orleans aquifer shows that annual fluctuations in the groundwater elevations range from 1 to 2 feet. Observation well Or-22 located to the east of Michoud near Chef Menteur was monitored from 1936 to 1962 and showed groundwater levels ranging from 0 to -7 feet elevation in an area distant from groundwater withdrawals. Observation well Or-22 was installed in a sand zone thought to be within the Gonzales-New Orleans aquifer, but now interpreted to be in the top of the 1,200-Foot Sand. **Figure 8** shows the location of observation well Or-22.

The maximum amount of subsidence in an aquifer potentially related to the decrease of water level in the aquifer can be estimated with the linear approximation (Freeze and Cherry, 1979):

$$db = \alpha \, b \, \rho \, g \, dh$$

where db is the change in aquifer thickness, α is the aquifer compressibility, b is the original thickness of the aquifer, ρ is the density of the groundwater, g is the acceleration of gravity, and dh is the total drawdown. The change in thickness of the aquifer resulting from groundwater level drawdown is the amount of compaction of the aquifer induced by pumping. The compaction of the aquifer provides an upper limit to the potential subsidence of the land surface above the aquifer that could result from the compaction of the aquifer alone. Based on aquifer compressibility values of 10^{-8} to 10^{-7} meters squared per Newton (m^2/Newton) for unconsolidated sands (Freeze and Cherry, 1979) and the thickness of the aquifer of 160 feet, the change of the aquifer thickness and ultimate amount of possible subsidence would range from 1.4 to 14 millimeters (mm) (0.05 to 0.5 inch) within the cone of depression in the 1-mile radius of the pumping well. The potential subsidence associated with the lower pumping rate of 3.9 gpm would be less than 1 mm within the one-mile radius. The potential total amount of subsidence would be lower at greater distances from the pumping well. The potential amounts of subsidence that could be induced by the proposed pumping would not be measurable relative to the variable amounts of subsidence estimated to be occurring in the Michoud area.

The ongoing rise of groundwater levels in the Gonzales-New Orleans aquifer will counteract the potential for any subsidence to be associated with the proposed groundwater pumping. The higher groundwater levels could stabilize any potential subsidence related to the historical pumping of the Gonzales-New Orleans aquifer and could potentially reverse subsidence in the aquifer.

2.4   Discussion of Subsidence Measurements

The question of subsidence induced by groundwater pumping in the New Orleans area received public attention after the publication in May 2016 of the research paper by Jones et al., (2016). This report has been referred to in the local press as the "NASA report" because of the affiliation of some of the report authors with the Jet Propulsion Laboratory, which is a NASA-affiliated research institute associated with the California Institute of Technology. Jones et al., (2016) assessed subsidence rates measured with interferometric Synthetic Aperture Radar (InSAR) images from two radar images of June 16, 2009 and July 2, 2012. The two radar images were collected from an aircraft flying at an altitude of 41,000 feet, which can provide higher spatial resolution in the radar image than satellite-acquired InSAR data. InSAR evaluation measures phase variations of the radar signal to assess elevation differences between separate synthetic aperture radar images (Ketelaar, 2009; Ferretti, 2014). Jones et al., (2016) stated that the subsidence rates determined by InSAR supported the conclusion that groundwater withdrawal is the primary subsidence driver in areas with major industry around New Orleans, particularly in

Norco and Michoud. This conclusion had been previously presented by Dokka (2011) based on InSAR data from Dixon et al., (2006). The subsidence rates reported by Jones et al., (2016) for Norco and Michoud ranged from 15 to 30 mm per year (mm/yr). Jones et al., (2016) further concluded that shallow drainage of surficial soils is the most important driver of subsidence in the urban areas. Jones et al., (2016) stated that the subsidence rates can extend to flood control structures located several kilometers distant from areas of higher subsidence rate. The conclusions of the Jones et al. (2016) report were widely reported in the New Orleans area after its publication.

Dixon et al., (2006) conducted a more-detailed evaluation of subsidence with InSAR data derived from a series of 33 satellite-acquired radar images from the period from 2002 to 2005. The Dixon et al., (2006) subsidence rates for the Michoud area are presented in **Figure 13** from Dokka's (2011) additional evaluation of the results. The Dixon et al., (2006) data showed subsidence rates ranging from 7 to 11 mm/yr in the area of the Michoud Plant. These rates are similar to and slightly larger than the average subsidence rates of 5 to 10 mm/yr in the New Orleans area resulting from compaction of the Holocene sediments (Tornqvist et al., 2008). Dokka (2011) suggested that subsidence in the Michoud area had been associated with the occurrence of groundwater pumping in the area, but did not evaluate the physical conditions of the Gonzales-New Orleans aquifer relative to the potential for subsidence that could be induced by groundwater withdrawal. Dokka (2011) did not evaluate the relationship of the distribution of subsidence rates to the amounts of groundwater drawdown or to the extent of the cone of depression in the Gonzales-New Orleans aquifer. Dokka (2011) concluded that the subsidence had slowed after 2001 and noted that there could be a potential for subsidence reversal associated with the rise of groundwater levels.

Figure 14 shows the Jones et al., (2016) subsidence rates for the Michoud area. The central portion of the cone of depression of the Gonzales-New Orleans aquifer had occupied the area within 1 mile of the Michoud Plant. This area had groundwater level drawdowns of 110 to 120 feet and would be expected to have the greatest amount of any subsidence induced by groundwater withdrawal. The subsidence rates shown by Jones et al., (2016) in the central portion of the cone of depression were highly variable and not consistent with the distribution of drawdown. The highest rates of subsidence in this radial area were in the range of 20 to 30 mm/yr and were interspersed with subareas with much lower subsidence rates on the order of 10 to 20 mm/yr. At distances of 0.5 to 1 mile from the Michoud Plant, the subsidence rates were lower (predominantly 10 to 15 mm/yr). However, the Jones et al., (2016) data showed higher subsidence rates at locations occupied by large structures (NASA Michoud facility) at distances greater than 1 mile from the Michoud Plant.

Jones et al., (2016) noted that a major limitation of their study was that only two radar images were used for the InSAR evaluation so that the effects of seasonal and environmental variations prior to and between the dates of the radar images could not be evaluated. They noted that river levels were higher in 2009 than in 2012. In addition, there were significant differences in other

hydrologic conditions between the two radar images. Review of U.S. Drought Monitor weekly drought classifications for Orleans Parish showed that no drought conditions occurred before the time of the 2009 radar image, but widespread drought conditions occurred in the month prior to the 2012 radar image. Variations in soil moisture can contribute to elevation changes, with higher ground elevations in wetter conditions and lower elevations in drier conditions. In this case, the drier conditions of the later (2012) radar image could have contributed to the elevation differences assessed between the two radar images. Jones et al., (2016) also stated that the uncertainties in the subsidence rates were high in the Michoud area because of the distance from the aircraft flight path and the high incidence angle of the radar. The uncertainties at the Michoud area were 15 to 25 mm/yr and were larger than the total subsidence rates reported by Dixon et al., (2006) and Dokka (2011).

In statements to the New Orleans area media[2], the lead author C.E. Jones of Jones et al., (2016) stated "additional research is needed to directly link groundwater pumping to the subsidence rates." In addition, Jones stated that it's unclear whether the subsidence results from groundwater withdrawal, compaction of soft soils and other geologic processes, or because of geologic processes, such as a nearby "Michoud fault".

The variability of the reported subsidence rates and their distribution suggest that the subsidence in the Michoud area is related to compaction of near-surface soils and peat and to the concentrated loads provided by large industrial structures.

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2 http://www.nola.com/environment/index.ssf/2016/05/new_orleans_area_sinking_assis.html

3.0   Conclusions

This section summarizes the conclusions of the evaluation of proposed groundwater pumping and subsidence at the proposed NOPS facility in Michoud. The conditions of the Gonzales-New Orleans aquifer in the NOPS area are presented followed by the conclusions concerning the potential for subsidence.

3.1   Gonzales-New Orleans Aquifer Conditions at Michoud

The Gonzales-New Orleans aquifer is of Pleistocene age and occurs in the depth range of between approximately 500 feet to 700 feet below sea level in the Michoud area. The north-south cross section (**Figure 4**) shows that the Gonzales-New Orleans aquifer is stratigraphically continuous with the Shallow aquifer of the north side of Lake Pontchartrain. The Shallow aquifer is the updip equivalent of the Gonzales-New Orleans aquifer and the recharge area.

In the area near Michoud and the proposed NOPS, the thickness of the Gonzales-New Orleans aquifer ranges from 155 to 170 feet. The top of the aquifer occurs at elevations ranging from -522 to -530 feet relative to sea level (NGVD 1929). The Gonzales-New Orleans aquifer consists of fine to medium sand and has hydraulic conductivity estimated to range from 80 to 120 ft/day. The transmissivity was estimated to range from 12,000 to 24,000 ft^2/day (approximately 90,000 to 180,000 gpd/ft). The storage coefficient is estimated to range from 0.0001 to 0.001 (dimensionless). The specific capacities of water wells in the Gonzales-New Orleans aquifer at the Michoud Plant have ranged from 24.6 to 49.7 gpm/ft and the average specific capacity was estimated to be 37.5 gpm/ft. These values of specific capacities are high and indicate that the water wells have high efficiency and productivity.

The Gonzales-New Orleans aquifer has been the principal source of groundwater supply for industry in the New Orleans area. In the period from the 1950s through 1980s, the major centers of groundwater withdrawal from the Gonzales-New Orleans aquifer were in downtown New Orleans, the Industrial Canal area near Lake Pontchartrain, and the Michoud area (Michoud Plant and other industry). The total groundwater withdrawals in Orleans Parish during this time interval were reported by the U.S. Geological Survey to range from 35 to 43 MGD.

In the 1990s the groundwater withdrawals from the Gonzales-New Orleans aquifer had decreased significantly because of plant closings in the downtown area and decrease of groundwater use for commercial air conditioning. The groundwater withdrawals from the

Gonzales-New Orleans aquifer decreased further by 2000 because of less usage in the Industrial Canal area. The total groundwater withdrawals in Orleans Parish during the 2000 to 2010 time interval were reported by the U.S. Geological Survey to range from approximately 5 to 13 MGD. The configuration of the cone of depression had shifted farther eastward to be centered on the Michoud area.

Groundwater levels in monitoring wells in the Gonzales-New Orleans aquifer show upward trends resulting from the significant decreases of groundwater withdrawals from the aquifer. The groundwater levels showed stabilization by the 1990s and strong upward recovery or rebound of 1.5 to 2 feet per year after 2000. The rapid rebound of groundwater levels is a result of the high hydraulic diffusivity of the Gonzales-New Orleans aquifer and the hydrologic continuity of the Gonzales-New Orleans aquifer with the region of higher hydraulic heads in the Shallow aquifer of the recharge area located north of Lake Pontchartrain.

Saline groundwater occurs in the aquifer at the NOPS facility and in the area to the east. The aquifer contains saline water to the south of the freshwater area. The interface between saline groundwater and fresh groundwater has occurred north of the NOPS site since the onset of groundwater use at the Michoud Plant. In 2008, the wells at the Michoud Plant had chloride concentrations of 458 to 559 mg/l and the TDS values have ranged from 685 to over 1,000 mg/l (Dial, 1983; Prakken, 2009). The Secondary MCL standard for chloride is 250 mg/l and for TDS is 500 mg/l so the groundwater at the NOPS site is not potable. In addition, the high color of the Gonzales-New Orleans aquifer groundwater exceeds the Secondary MCL for color.

3.2   Possible Subsidence Conditions at Michoud

ENOI is evaluating two alternatives for electrical generation at the NOPS facility. The makeup water for process water, service water, and fire protection for these alternatives may be derived from the existing water-supply well system in the Gonzales-New Orleans aquifer. The SCGT alternative is expected to need a maximum groundwater supply of up to 96 gpm (0.138 MGD). The RICE generating alternative is expected to need a groundwater supply of up to 3.9 gpm (0.005 MGD). The proposed groundwater usage for these alternatives is significantly lower than the historical use of groundwater by the Michoud Plant during its operation.

The drawdown distributions were calculated with the drawdown equation for the proposed pumping rates of 96 gpm and 3.9 gpm. The transmissivity value for the Gonzales-New Orleans aquifer was assigned as 14,300 ft^2/day (106,964 gpd/ft). The storage coefficient was assigned to be 0.0001 (dimensionless). The drawdown was calculated for a time duration of 10 years of pumping. For the pumping rate of 96 gpm (the highest proposed pumping rate), the

estimated drawdown will range from 2.1 feet within 50 feet of the pumped well to 1.0 feet at a distance of 2 miles (10,560 feet). For the 3.9 gpm pumping rate, the drawdowns will range from 0.08 feet (approximately 1 inch) to less than 0.04 feet at distances of 1 to 2 miles.

The proposed NOPS groundwater withdrawals will be too small to contribute to any subsidence in the Michoud area. For the 96 gpm pumping rate, the change of the aquifer thickness and ultimate amount of possible subsidence is estimated to range from 1.4 to 14 mm (0.05 to 0.5 inch) within the cone of depression in the 1-mile radius of the pumping well. The possible subsidence associated with the lower pumping rate of 3.9 gpm is estimated to be less than 1 mm within the 1-mile radius. The possible total amount of subsidence would be lower at greater distances from the pumping well. The possible amounts of subsidence that could be induced by the proposed pumping would not be measurable relative to the variable amounts of subsidence estimated to be occurring in the Michoud area.

Recent research on subsidence rates in the Michoud area shows conflicting and inconsistent results. The estimated rates of subsidence presented by Jones et al., (2016) are highly variable within the center of the cone of depression within the 1-mile radius of the Michoud Plant and do not coincide with the region that had the largest groundwater level drawdowns. The subsidence rates presented by Dixon et al., (2006) and Dokka (2011) for the Michoud area are similar to the average subsidence rates of the New Orleans area. The Jones et al., (2016) subsidence rates had very high uncertainties of 15 to 25 mm/yr in the Michoud area. The uncertainties were related to the flight path of the aircraft collecting the InSAR data and the high incidence angle of the radar reflections. The uncertainties were on the order of the reported subsidence rates and call into question the validity of the Jones et al., (2016) conclusion that groundwater withdrawal is the primary subsidence driver in Michoud. The research results on subsidence rates in the Michoud area can be explained by subsidence being related to compaction of shallow organic-rich sediments such as peat and settlement associated with large structures.

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Figures

NOPS
ENTRANCE
LAT: 30° 0' 44.75"
LONG: 89° 56' 14.43"

SITE
LOCATION

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N

2,000   1,000   0   2,000
Feet

REFERENCE:
Coordinates provided in Geodetic Datum NAD 83, Latitude and Longitude is shown in Degrees, Minutes, Seconds.

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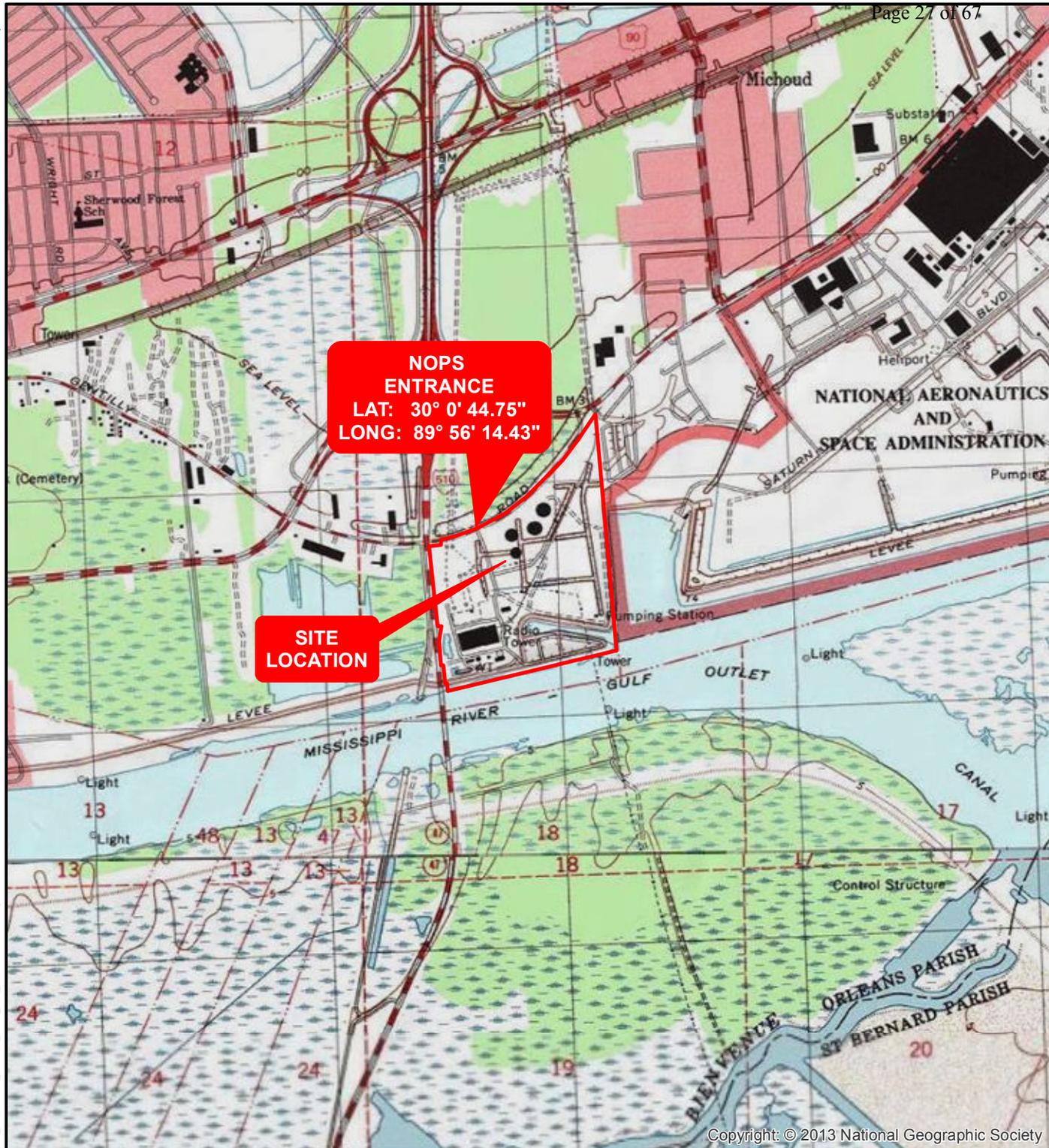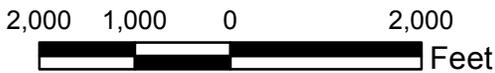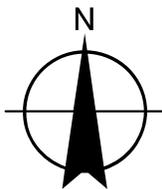
NEW ORLEANS POWER STATION PROJECT
INFORMATION SUBMITTAL
NEW ORLEANS, ORLEANS PARISH, LOUISIANA

FIGURE
NUMBER

1

SITE LOCATION

CB&I Government Solutions, Inc.
4171 Essen Lane
Baton Rouge, Louisiana 70809

LOCATION OF GEOLOGIC CROSS SECTIONS

NEW ORLEANS POWER STATION PROJECT
INFORMATION SUBMITTAL
NEW ORLEANS, ORLEANS PARISH, LOUISIANA

FIGURE NUMBER: 2

CB&I Government Solutions, Inc.
4171 Essen Lane
Baton Rouge, Louisiana 70809

Legend

● CONTROL POINT - Water, oil, or gas well drill site
— Location of hydrogeologic section
▭ Location of Proposed NOPS
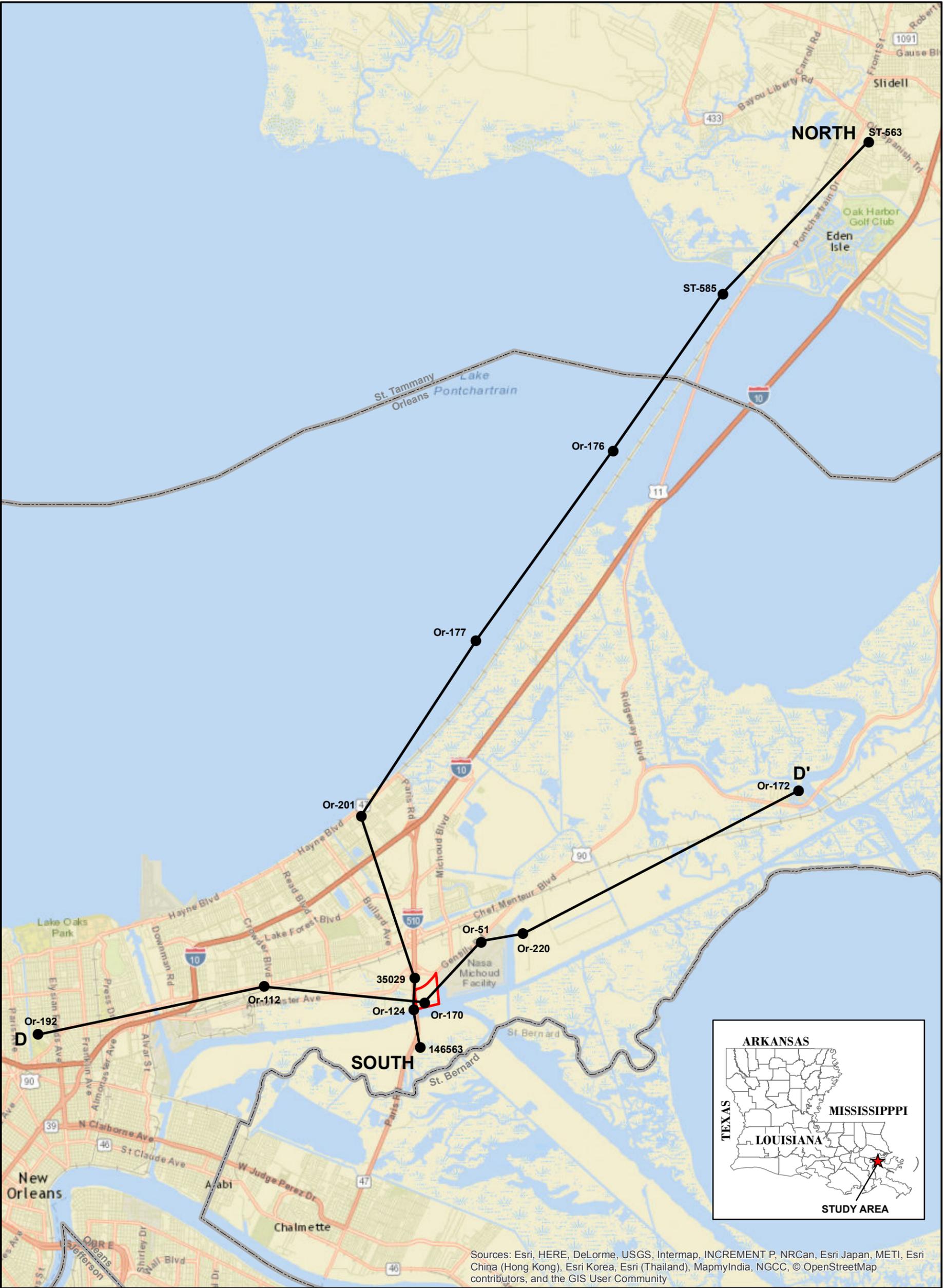
Sources: Esri, HERE, DeLorme, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), MapmyIndia, NGCC, © OpenStreetMap contributors, and the GIS User Community

Louisiana Department of Transportation and Development—U.S. Geological Survey Water Resources Cooperative Program

WEST-EAST GEOLOGIC CROSS SECTION

FIGURE NUMBER 3

NEW ORLEANS POWER STATION PROJECT
INFORMATION SUBMITTAL
NEW ORLEANS, ORLEANS PARISH, LOUISIANA

CB&I Government Solutions, Inc.
4171 Essen Lane
Baton Rouge, Louisiana 70809
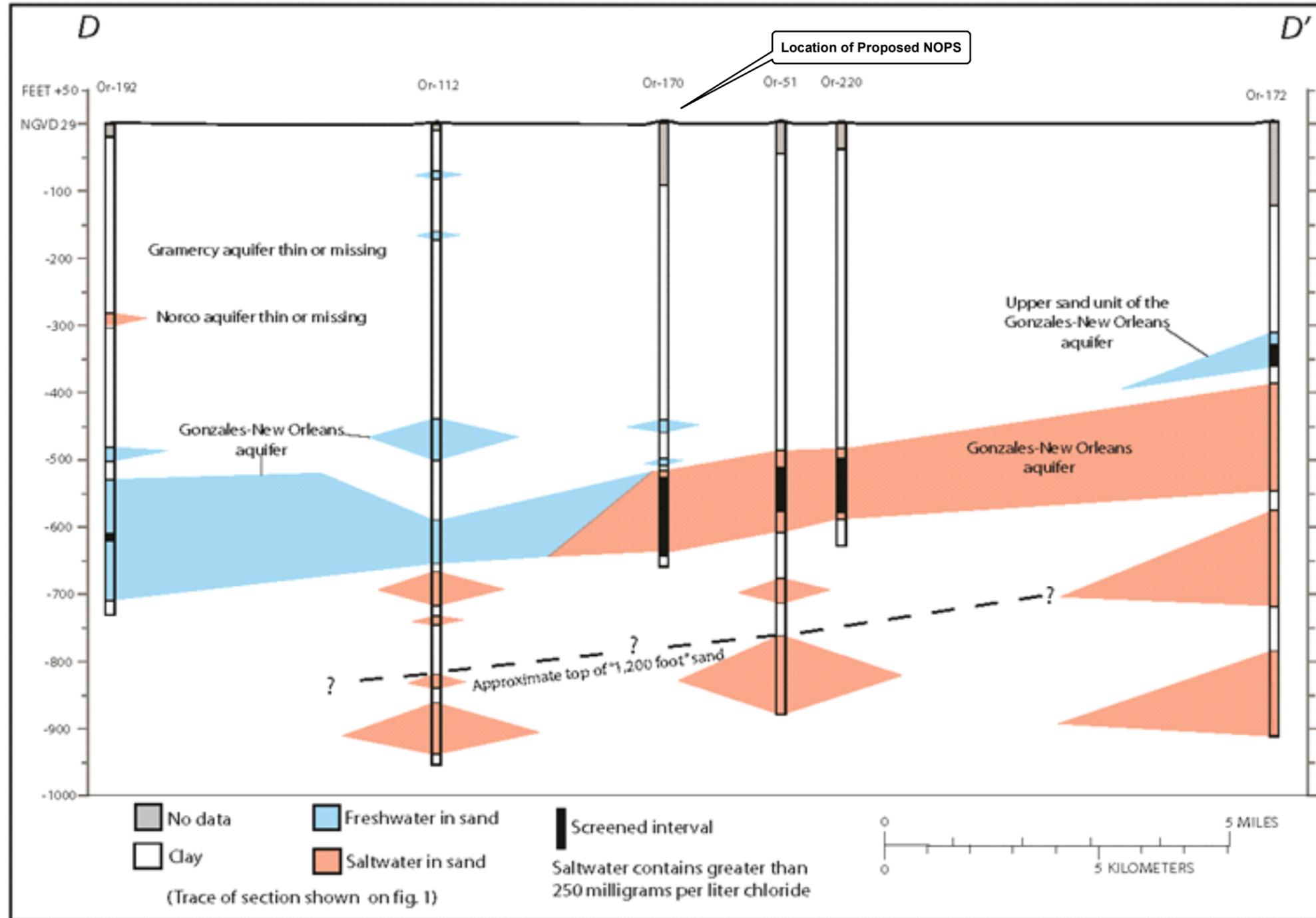
REFERENCE:
Prakken, 2009: Figure 7. Hydrogeologic section D-D' showing major sand units from central
Orleans Parish to northeastern Orleans Parish, New Orleans area, southeastern Louisiana.

NORTH

FEET
NGVD 29

0
-100
-200
-300
-400
-500
-600
-700
-800

ST-563
Bottom at 2430'

ST-585
Bottom at 3051'

OR-176
Bottom at 2972'

OR-177
Bottom at 1982'

OR-201
Bottom at 803'

35029
Bottom at 2500'

OR-124
146663

Bottom at 654'

Bottom at 4006'

SOUTH
LOCATION OF PROPOSED NOPS

0
-100
-200
-300
-400
-500
-600
-700
-800

1200-foot Sand

Gonzales-New Orleans Aquifer

Upper Sand Unit of the Gonzales-New Orleans Aquifer

MILES
0 3 6

No data
Clay
Freshwater in sand
Saltwater in sand

Screened Interval
Saltwater contains greater than
250 milligrams per liter chloride

NOTE: North-south cross section prepared using geophysical
logs for wells from LDNR SONRIS database.

Major sand units are shown.

CBI

FIGURE NUMBER
4

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Entergy.

NORTH-SOUTH GEOLOGIC
CROSS SECTION

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LAKE PONTCHARTRAIN

LAKE BORGNE

NOPS

EXPLANATION

—50— WATER-LEVEL CONTOUR SHOWING ALTITUDE OF WATER LEVEL. CONTOUR INTERVAL 10 FEET WITH 5-FOOT SUPPLEMENTAL CONTOUR (DASHED). DATUM IS MEAN SEA LEVEL. (CONTROL POINTS SHOWN)

0 1 2 3 4 5 6 MILES

Entergy

NEW ORLEANS POWER STATION PROJECT
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FIGURE NUMBER	**POTENTIOMETRIC MAP SEPTEMBER 1963 GONZALES-NEW ORLEANS AQUIFER**
5	

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REFERENCE:
Rollo, 1966: Plate 10. Water level in the "700-foot" sand, September 16-20, 1963,
New Orleans Area, Louisiana.
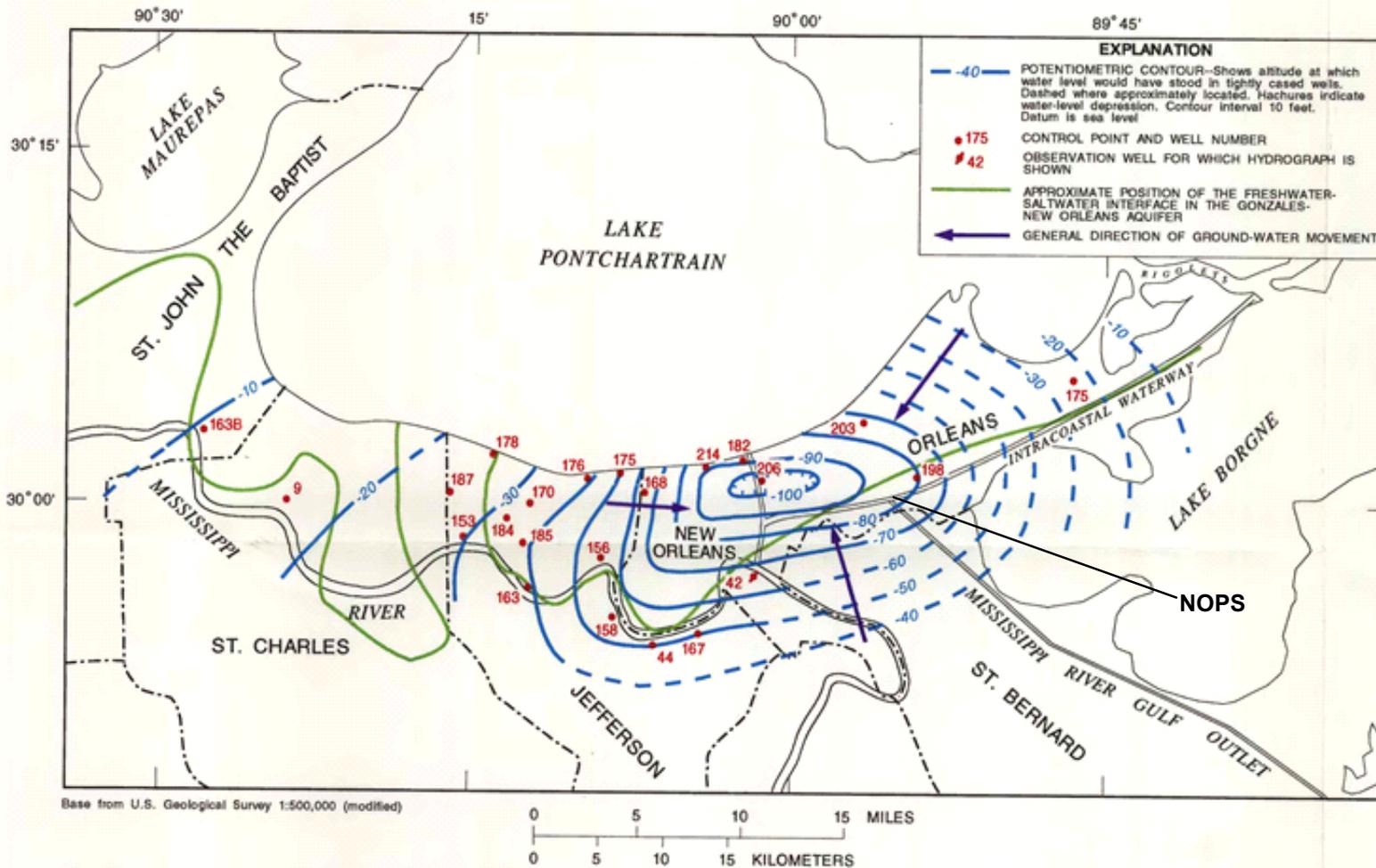
J:\Drafting\Entergy\155004 (NOPS)\ArcView\GIS_Documents\Project_Maps\nops_155004_0030_pot_map_1963.mxd\ Analyst: debbie.comeaux\ Date: 5/30/2017 1:29:58 PM

Base from U.S. Geological Survey 1:500,000 (modified)

EXPLANATION

POTENTIOMETRIC CONTOUR—Shows altitude at which water level would have stood in tightly cased wells. Dashed where approximately located. Hachures indicate water-level depression. Contour interval 10 feet. Datum is sea level

● 175 CONTROL POINT AND WELL NUMBER

↗ 42 OBSERVATION WELL FOR WHICH HYDROGRAPH IS SHOWN

APPROXIMATE POSITION OF THE FRESHWATER-SALTWATER INTERFACE IN THE GONZALES-NEW ORLEANS AQUIFER

GENERAL DIRECTION OF GROUND-WATER MOVEMENT

	NEW ORLEANS POWER STATION PROJECT INFORMATION SUBMITTAL NEW ORLEANS, ORLEANS PARISH, LOUISIANA	
FIGURE NUMBER **6**	**POTENTIOMETRIC MAP SPRING 1993 GONZALES-NEW ORLEANS AQUIFER**	
CBI	CB&I Government Solutions, Inc. 4171 Essen Lane Baton Rouge, Louisiana 70809	

REFERENCE:
Walters, 1995: Figure 3. Potentiometric surface of the Gonzales-New Orleans aquifer, spring 1993.

Louisiana Department of Transportation and Development—U.S. Geological Survey Water Resources Cooperative Program

Map Credit: Modified from Louisiana Oil Spill Coordinator, Office of the Governor,
Louisiana GIS CD: A Digital Map of the State, Version 2.0

Explanation

BOUNDARY OF STUDY AREA

O-216 CONTROL POINT AND WELL NUMBER

-70 POTENTIOMETRIC CONTOUR--Shows altitude
at which water level would have stood in tightly
cased wells.
Dashed where approximately located.
Contour interval, in feet, varies.
Datum is National Geodetic
Vertical Datum of 1929

O-175 CONTROL POINT AND WELL NUMBER FOR WHICH
HYDROGRAPH IS SHOWN (see fig. 12)

1.9 WATER WITHDRAWAL CENTER--Average withdrawal
rate in million gallons per day (Mgal/d) for 2007

FLOW ARROWS --Shows general direction
of ground-water movement

0   5 MILES

0   5 KILOMETERS

Entergy

NEW ORLEANS POWER STATION PROJECT
INFORMATION SUBMITTAL
NEW ORLEANS, ORLEANS PARISH, LOUISIANA

FIGURE NUMBER	POTENTIOMETRIC MAP SPRING 2008 GONZALES-NEW ORLEANS AQUIFER
7	

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GROUNDWATER LEVEL TRENDS

FIGURE NUMBER 8

NEW ORLEANS POWER STATION PROJECT
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NEW ORLEANS, ORLEANS PARISH, LOUISIANA

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Legend

Location of Proposed NOPS

Louisiana Department of Transportation and Development—U.S. Geological Survey Water Resources Cooperative Program

90°15' 90°10' 90°05' 90°00' 89°55' 89°50' 89°45'

30°10'
30°05'
30°00'
29°55'

ST. TAMMANY PARISH
ORLEANS PARISH
ST. CHARLES PARISH
JEFFERSON PARISH
JEFFERSON PARISH
ORLEANS PARISH
LAKE PONTCHARTRAIN CAUSEWAY

LAKE PONTCHARTRAIN

No data
No data
No data
No data
No data

Saltwater area
Saltwater area
Saltwater area
Saltwater area

University of New Orleans
New Orleans International Airport
Lakefront Airport

Kenner
Metairie
Gentilly
Michoud
Harahan
Bridge City
New Orleans
Arabi
Chalmette
Meraux
Westwego
Marrero
Harvey
Gretna

ST. BERNARD PARISH
ORLEANS PARISH
PLAQUEMINES PARISH

NOPS

Well data points:
Jf-178 1430 ▲ -700
Jf-171 ▲ 425 -558
Jf-177 ● 44.2 -650
Jf-176 ● 92.8 -810
Jf-175 ▼ 57 -640
Jf-170 ● 66.6 -741
Jf-184 1600 ▲ -704
Jf-112 ● 59.2 -775
Jf-149 ● 125 -748
Jf-8260Z ● 58.9 -738
Jf-143 ● 71.2 -752
Jf-222 ● 89.3 -725
Jf-25 ● 275 -364
Jf-28 ● 318 -792
Jf-163 ▼ 167 -755
Jf-200 ● 405 -830
Jf-160 ● 895 772 -830
Or-224 ● 501k -756
Or-254 ● 145 -885
Jf-207 ● 348 -840
Jf-212 ● 363 -830
Jf-191 ● 1310 -810
Jf-167 ● 718 -723
Jf-181 ● 724 -740
Or-212 ● 102 -598
Or-220 ● 511 -580
Or-221 ● 614 -580
Or-252 ● 417 -595
Or-199 ● 312 -587
Or-208 ● 559 -626
Or-167 ● 388 -445
Or-170 ● 458 -642
Or-125 ● 537 -629

Map Credit: Modified from Louisiana Oil Spill Coordinator, Office of the Governor, Louisiana GIS CD: A Digital Map of the State, Version 2.0

0   5 MILES
0   5 KILOMETERS

INDEX MAP
ARKANSAS
TEXAS
MISSISSIPPI
LOUISIANA
Study Area
Enlarged Area

Explanation

Area where the Gonzales-New Orleans aquifer contains freshwater (modified from Rollo, 1966; Hosman, 1972; Dial, 1983; and Tomaszewski, 2003)

Area where the Gonzales-New Orleans aquifer contains freshwater underlain with saltwater (modified from Rollo, 1966; Hosman, 1972; Dial, 1983; and Tomaszewski, 2003)

BOUNDARY OF STUDY AREA

Or-212 ● 102 -598   CONTROL POINT--Water well, chloride concentration in milligrams per liter, and bottom of well elevation, NGVD 29. An upward triangle indicates chloride concentrations are increasing at the well site (saltier); downward, decreasing (fresher) Round dot, indeterminate

Jf-184 ▲ 160 -704   OBSERVATION WELL WITH CHLOROGRAPH (see fig. 14)

Saltwater contains greater than 250 milligrams per liter chloride

REFERENCE:
Prakken, 2009: Figure 13. Distribution of freshwater in the Gonzales-New Orleans aquifer, New Orleans area, southeastern Louisiana, 2008.

SITE LOCATION

Well 8
Well 6
Well 4
Radio
Well 5
Well 2
Well 1
Well 3

Tower
Pumping Station
GULF OUTLET
Light
MISSISSIPPI RIVER

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N

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INFORMATION SUBMITTAL
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FIGURE NUMBER

10

NOPS WATER WELLS

1,000   500   0   1,000
Feet

CBI

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REFERENCE:
Coordinates provided in Geodetic Datum NAD 83, Latitude and Longitude is shown in Degrees, Minutes, Seconds.

SITE LOCATION
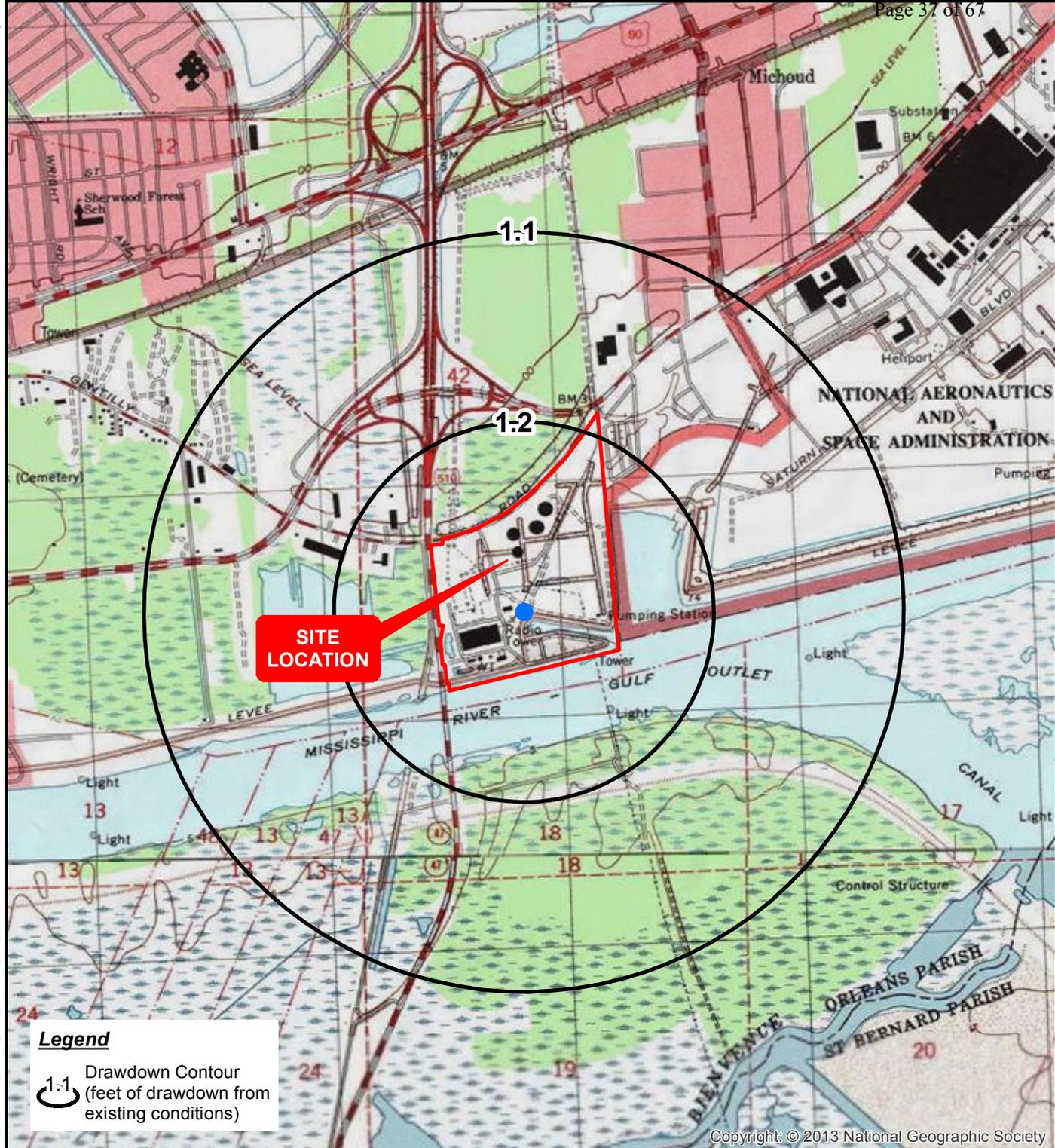
Legend

1-1 Drawdown Contour (feet of drawdown from existing conditions)
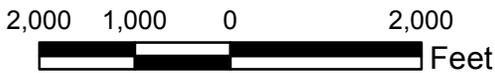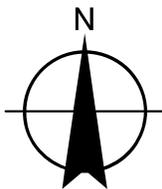
Entergy

NEW ORLEANS POWER STATION PROJECT
INFORMATION SUBMITTAL
NEW ORLEANS, ORLEANS PARISH, LOUISIANA

FIGURE NUMBER 11

ESTIMATED MAXIMUM DRAWDOWN, PROPOSED PUMPING AT 96 GPM

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N

2,000 1,000 0 2,000 Feet

REFERENCE:
Coordinates provided in Geodetic Datum NAD 83, Latitude and Longitude is shown in Degrees, Minutes, Seconds.

NOTE: Calculation of drawdown profile based on pumping of Well #6 (or Well #5) at an average rate of 96 gpm. Cross section based on site topography. Calculated drawdown in feet in parentheses.

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NEW ORLEANS POWER STATION PROJECT
INFORMATION SUBMITTAL
NEW ORLEANS, ORLEANS PARISH, LOUISIANA

FIGURE NUMBER	ESTIMATED MAXIMUM DRAWDOWN CROSS SECTION PROPOSED PUMPING AT 96 GPM
12	

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Baton Rouge, Louisiana 70809

Figure 11. Map of the Michoud area of New Orleans showing vertical velocities derived from InSAR analysis of *Dixon et al.* [2006]. The heavy dashed black line is the Michoud fault of *Dokka* [2006]; this fault is probably best described as a shear zone (black ruled zone). InSAR velocities for 2003–2005, in mm yr^{-1}: red dots, <−17; yellow, −17 to −13; orange, −13 to −7; green, −7 to 0; blue triangles, water wells. Field investigation showed that InSAR permanent scatterers in the area correlate mainly with reflecting surfaces on single-story homes. It has been standard construction practice in New Orleans since the 1950s to build such homes on pilings that completely penetrate Holocene deposits (C. Mugnier, personal communication, 2010). Because the monumentation of the InSAR is similar to both leveling and water level gauge measurements, the results are comparable. See text for discussion.

J:\Drafting\Entergy\155004 (NOPS)\ArcView\GIS_Documents\Project_Maps\nops_155004_0038_subsidence_rates.mxd; Analyst: D.Comeaux; Date: 5/30/2017 11:43:35 AM
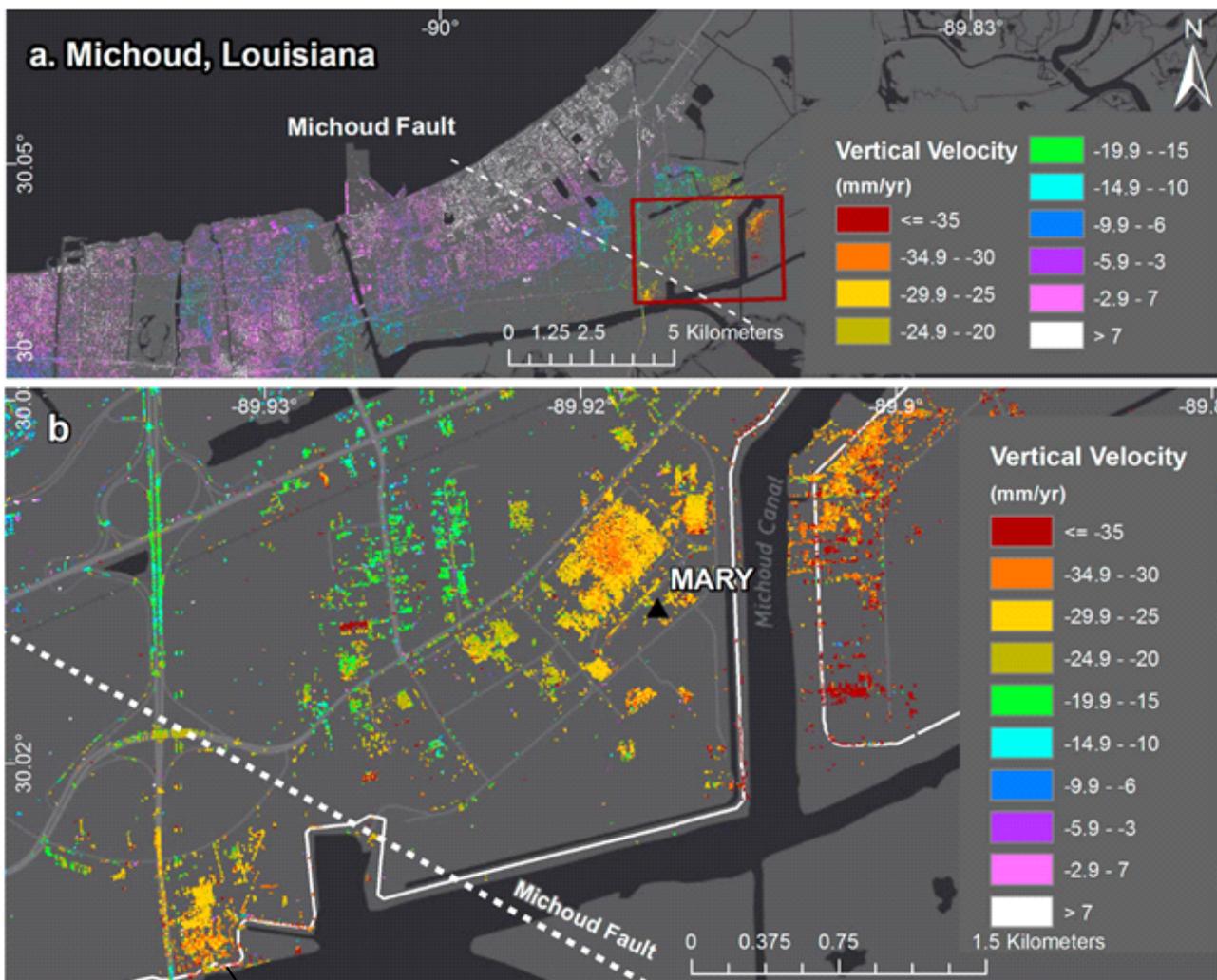
NOTE: Figure 11 from Dokka (2011) showing INSAR subsidence rates in mm/yr from Dixon et al (2006).

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NEW ORLEANS POWER STATION PROJECT
INFORMATION SUBMITTAL
NEW ORLEANS, ORLEANS PARISH, LOUISIANA

FIGURE NUMBER

13

MICHOUD AREA SUBSIDENCE RATES FROM DIXON (2006)

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NOTE: Figure 4 from Jones et al (2016) showing INSAR subsidence rates in mm/yr based on 2009 and 2012 radar imagery.

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NEW ORLEANS POWER STATION PROJECT
INFORMATION SUBMITTAL
NEW ORLEANS, ORLEANS PARISH, LOUISIANA

FIGURE NUMBER	MICHOUD AREA SUBSIDENCE RATES FROM JONES ET AL (2016)
14	

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Appendix A
Michoud Plant Water Well Information

This form is used for an abandoned hole or well

FORM. LDPW-GW-2

JAN 07 1983   071-124

LOUISIANA DEPARTMENT OF PUBLIC WORKS

WATER-WELL ABANDONMENT AND PLUGGING [STATE ACT 535 (1972)]

LA DEPT OF PUBLIC WORKS

1. WELL OWNER: (if different from owner when drilled, note in item 5)

New Orleans Public Service, Inc.   SEP 04 1984

ADDRESS 317 Baronne Street, New Orleans, La.

OWNERS WELL NUMBER (if any) Well #1

2. LOCATION OF WELL Parish: Orleans in SECTION 42

TOWNSHIP +25 1/2 RANGE +13E well is near   approximately

Miles from at Michoud Generating Station
(Crossroads, Town, Railroad, any Landmark, etc.)

Old Gentilly and Parish Road N. O. L.
(IF POSSIBLE PLEASE ATTACH MAP OR PLAT SHOWING LOCATION)

3. WELL INFORMATION: Depth of hole, 634 ft., Depth of completed well,

634 ft. Date completed 1956 by (Give name and address of water-

well contractor who installed well or hole): Menge Well & Pump Co.

4. Describe in detail how well or hole was plugged: (materials used, amount of casing and/or screen removed, or left in hole, etc.) Well plugged by pumping cement through pipe at bottom screen 100% coverage by Halliburton. All screen & casing left in hole.

5. REMARKS:

I certify that this work was done and completed in accordance with Rules and Regulations of the State on _____, 19____ by (name and address of contractor or owner) Menge Well & Pump Co.

_____ (Signature)

12/17/82
(Date)

SEE REVERSE SIDE OF 4th COPY FOR INSTRUCTIONS

OFFICE USE ONLY

State	Parish	Local Well No.	Identification Number
2 2	0 7 1	1 2 4	3 0 0 0 2 3 0 1 8 9 5 6 4 0
1	3	5 6	11 12 26
		2 6	

ID 3000260895614 ON

WELL SCHEDULE

Owner No. Michoud #1

U. S. DEPT. OF THE INTERIOR **GEOLOGICAL SURVEY**
WATER RESOURCES DIVISION **LOUISIANA DISTRICT**

Punched and Verified

Well No. OR-124

CARD A (MASTER CARD)

Record by: JR Rollo   Date: 1/21/60   Source of data: Correspondence NOPSI 1/19/

State: La   W 2   County: ORLEANS   3 6

Latitude: 3 0 0 0 2 6 N/S N   Longitude: 0 8 9 5 6 1 4   Sequential number: 1   Lat-long accuracy: 1

Local well number: 1 2 4 sq   Township: 1 2 N/S S   Range: 1 3 E/W E   Section: 4 2

Local use: _____   Quadrangle: Little Woods 1 9 1 C

Owner: New Orleans Public Service Inc   NEW ORLEANS, PSI

Ownership: N   Use of water: 8 CU   Use of well: W Z *   DATA AVAILABLE: Well data: 1   Frequency W/L meas.: I   Field aquifer characteristics: _____

Hyd. lab. data: C   Q. W. data: P   Frequency sampling: I   Pumpage inventory: no   Period: _____   Aperture cards: yes   Log data: D

CARD B (WELL-DESCRIPTION CARD)

Boxes 1-19 same as on Card A   Well depth: Est. Rept. 6 3 4   Accuracy: 6   Depth cased (first perf.): 5 3 4

Casing type: aulv   Diam.: 1 6   Finish: S   Method drilled: H   Date completed: 3/22/56 1 5 6

Driller: Menge Well & Pump Co. Inc   Address: 280 Eashart New Orleans

Pump intake setting: 2 5 0   Lift type: T   Deep/Shallow: D   H. P. 50   Power type: W   Alt. LSD: Topo 3

Other pump data: No stages 5   Diam. 14"   Column diam. 10"   Ft piece length 20'   Diam. 10'   Capacity 1400 gpm against 350 ft. head

Alt. LSD accuracy: 3   MP description: _____

Water level: above below MP; Ft below LSD 7B-6/28/59 6 3   Accuracy: G   Date meas.: 3 5 6

Yield: 2 4 5 9   Method determined: _____   Drawdown: 9 1   Accuracy: 6   Pumping period: _____

QUALITY OF WATER DATA: Iron _____   Sulfate _____   Chloride 5605   Hard. 55 3

Sp. Cond. 2520 6   Temp. °F _____   Field pH _____   Date sampled 11-2-71   N 71

CARD C (HYDROGEOLOGIC CARD)

Boxes 1-19 same as on Card A   Physiographic Province: COASTAL PLAIN 0 3   Section: MISS ALLUVIAL PLAIN E

Drainage Basin: 1 4 E   Subbasin: _____   Topography of well site: E

MAJOR AQUIFER: System Quat Q   Series Pleist G   Aquifer, formation, or group G=Ng   G N

Lithology _____ S   Origin _____   Aquifer thickness Dr. log 1 2 4

Length of well open to: 534-634 1 0 0   Depth to top of aquifer: 5 2 2

MINOR AQUIFER: System _____   Series _____   Aquifer, formation, or group _____

Lithology _____   Origin _____   Aquifer thickness _____

Length of well open to: _____   Depth to top of aquifer: _____

Depth to consolidated rocks: _____   Source of data: _____   Depth to basement: _____   Source of data: _____

Surficial material: _____   Infilt. char.: _____   Coefficient of transmissibility: _____   Coefficient of Storage: _____   Card no.: _____

OR-1-124

CARD A✳(SUPPLEMENTAL CASING RECORD)

Boxes 1-19 same as on Card A

Diameter	Fract.	Type	Length	Depth to top
1 6		I	2 9 7	0
(20 21)	(22)	(23)	(24 25 26 27)	(28 29 30 31)
1 2 6		I	2 1 7	2 9 7
(32 33)	(34)	(35)	(36 37 38 39)	(40 41 42 43)
9 5		I	2 0	5 1 4
(44 45)	(46)	(47)	(48 49 50 51)	(52 53 54 55)

Other data: (68 70 71 72 73 74 75 76 77)

Card No.: (78) Card designation: A ✳ (79 80)

CARD B✳(SUPPLEMENTAL SCREEN RECORD)

Boxes 1-19 same as on Card A

Diameter	Fract.	Type	Length	Depth to top	Opening size
9 5			1 0 0	5 3 4	0 0 9
(20 21)	(22)	(23)	(24 25 26)	(27 28 29 30)	(31 32 33)

Other data: (76 77)

Card No. (78) Card designation: B ✳ (79 80)

CARD C✳(SUPPLEMENTAL YIELD AND SPECIFIC-CAPACITY DATA CARD)

Boxes 1-19 same as on Card A

Yield	Drawdown	Specific Capacity	Pump. per. (hrs)	Date meas.	
2 4 5 0	9 1 .	2 6 . 9		3-56	3 5 6
(20 21 22 23)	(24 26 . 27 28)	(29 30 31 . 32)	(33 34 35)		(36 37 38)
1 6 7 0	6 8 .	2 4 . 6		8-28-59	8 5 9
(39 40 41 42)	(43 44 45 . 46 47)	(48 49 50 . 51)	(52 53 54)		(55 56 57)
(56 59 60 61)	(63 64 . 65 66)	(67 68 69 . 70)	(71 72 73)	Date meas.	(74 75 76)

Card No.: (77 78) Card desig: C ✳ (79 80)

Boxes 1-19 same as on Card A

				Date meas.	
(20 21 22 23)	(24 25 26 . 27 28)	(29 30 31 . 32)	(33 34 35)		(36 37 38)
(39 40 41 42)	(43 44 45 . 46 47)	(48 49 50 . 51)	(52 53 54)	Date meas.	(55 56 57)
(56 59 60 61)	(62 63 64 . 65 66)	(67 68 69 . 70)	(71 72 73)	Date meas.	(74 75 76)

Card No.: (77 78) Card desig: C ✳ (79 80)

MP2

MP2 is bottom inside edge of 2" gate, 3.85' above concrete slab at lsd.

2.85'

←1.0'→

concrete slab   LSD

SPECIFIC CAPACITIES

Yield	DD	SpCap
2450	91	26.9
1404	51	27.5
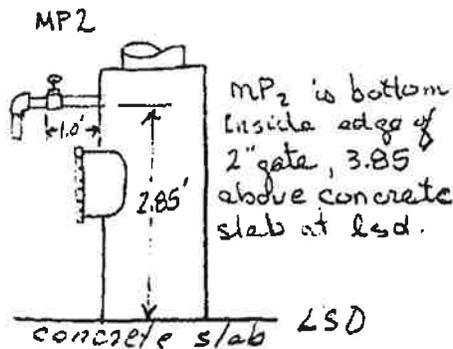
SKETCH AND DIAGRAM
See SKETCH OR-125

CHEMICAL ANALYSIS
9-28-56 - by F J Hoffman

Color : Amber
Turbidity = None
Conductivity in Ohms @ 77°F = 65.0
total dissolved solids = 700 ppm
pH = 8.35
Ammonia Nitrogen = 0.45 ppm
Total Alkalinity as $CaCO_3$ = 350
Total Chloride as $NaCl$ = 225 ppm
Total Sulphates as Na_2SO_4 = trace

CARD D*(SUPPLEMENTAL WELL-DESCRIPTION CARD)

Boxes 1-19 same as on Card A

Driller: M E N G E   W E L L   A N D   P U M P   C O

Test hole depth: 6 5 4   Pumpage: Hrs/day ____   Days/week ____   Weeks/year ____   Average rate ____

Accuracy ____   Pumpage year: ____   Coefficient of Permeability: ____   Field pH: ____

Lithologic samples available: N   Depth interval range: ____ to ____   Other data: ____

NOTES: Casing cemented by Halliburton Co. well numbers assigned to well sites. #2 drilled prior to #1. = PLUGGED ; ABANDONED - SEE LOPW ABAND. FORM

Card designation: D *

LITHOLOGIC LOG

Lithology	Thickness	Depth	Aquifer or unit name
top soil	5	5	
clay	10	15	
sand	15	30	
sand and sandy clay	67	97	
shale, sandy	43	140	
shale, and sandy shale	35	175	
shale, soft	121	296	
shale, sticky	74	370	
shale, sandy	86	456	
sand	18	474	
shale	48	522	
sand	124	646	
shale	8	654	

MECHANICAL ANALYSIS

DEPTH	% RETAINED				
	.016	.014	.012	.010	.008
522-542	—	4	10	23	18
542-565	5	12	25	26	16
565-588	—	6	10	25	27
588-610	—	5	15	33	28
618-633	11	15	20	24	14
633-640	5	12	22	25	15

ID- 3000266895 61401

Owner No. __1__

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

Well No. _Or - 124_

Elevation _____

Parish _Orleans_

Owner _New Orleans Public Service, Inc_ Address _317 Baronne St._
New Orleans 9, La.

Location _Michoud Generating Station_ Sec. _42_, T. _12 S_. R. _13E_

Driller _Menge Pump + Machinery Co., Inc._ Address _549 Dryades New Orleans 1_

Depth of test hole _____654_____ ft., Depth of well _635' - 4"_

Type of well: Dug, Driven, Bored, [Drilled,] Jet _____ Completed _22 March_ 195_

Stratigraphic unit _____ Log: [D.,] E., (W or C) _____

Casings: Kind _8A-2 T+C Galvanized + Coating_; size _16" OD_; length _296-8'_ ft.; between _0_ and _296'-8"_ f_
    Kind _do._; size _12 3/4 OD_; length _227'3"_ ft.; between _296'8"_ and _523'11"_ f_
    Kind _____; size _9 8 OD_; length _20'8"_ ft.; between _513'11"_ and _533'-8"_ f_

Screen record (diam., opening, setting) _9 5/8" — .009 gauge red brass_
screen 50 mesh — 100 ft from 533'-8" to 633'8"

Pump: Make and Type _F-M DWT_ Stages: No. _5_, Diam. _14_ i_
    Pump setting _160_ ft.; length and diameter of footpiece _20_ ft. _10_ i_
    Capacity _1400 GPM against 350' head_; Column diameter _10_ i_
    Power, kind: _Electric_ H.P. _150_ R.P.M. _1750_

Static level _63_ ft. (rept), meas. _Mar_ 195_6_, above (below) LS

_____ which is _____ ft. above, below land surfac_

Pumping level _154_ ft. Yield _2450_ gpm _Mar_ 195_
See over
Drawdown _91_ ft. after pumping — hours at _2450_ gpm _Mar_ 195_

Specific capacity _26.9_ while pumping _2450_ gpm _Mar_ 1956; Hrs/day in use _____

Use: [Ind.] Irr., P.S., Dom., Stock, Obs., Test, _____
    Amount (gpd): Average _____, maximum _____, minimum _____

Quality _See over_

Odor _____ Sample _____ Date _____ 19 Temp.(°F) _____

Source of data _Correspondence New Orleans Public Service 19 Jan 60_

Recorded by _J R Rollo_ Date _21 Jan 60_; Rescheduled by _____ Date _____

Remarks: _Mech. Analyses made by driller on reverse_
 # Casing cemented by Halliburton

Quadrangle _171-_

(Revised May 1, 1958)

Well No. _Or - 124_

Well No. *Or-124*

LOG OF WELL

Type of rock	Thickness	Depth
Top soil	5	5
Clay	10	15
Sand	15	30
Sand + Sandy clay	67	97
Shale, sandy	43	140
Shale + Sandy shale	35	175
Shale, soft	121	296
Shale, sticky	74	370
Shale, sandy	86	456
Sand	18	474
Shale	48	522
Sand	124	646
Shale	8	654

Chemical Analysis
28 Sept 56   by F. J. Hoffman

Color	Amber
Turbidity	None
Conductivity in OHMS @ 77°F	65.
Total Dissolved Solids ppm	700
pH	8.35
Ammonia Nitrogen ppm	0.45
Total Alkalinity as CaCO₃	350
Total Chloride as NaCl ppm	225
Total Sulphates as Na₂SO₄ ppm	Trace

Specific Capacities

Yield	DD	Spu. Cap.
2450	91	26.9
1404	51	27.5

Mechanical Analysis

% Retained

Depth	.016	.014	.012	.010	.18
522-542	—	4	10	23	18
542-565	5	12	25	26	16
565-588	—	6	10	25	27
588-610	—	5	15	33	28
610-633	11	15	20	24	14
633-640	5	12	22	25	15

SKETCH AND DIAGRAM

Test run by N.O.P.S on well
Aug 28, 1959   test ran 6 min after shutdown
Water level 78'
Flow 1670 with pumping level of 146'
D.D. - 68'
Sp. Cap = 25.3 24.6

See sketch of
plant for location
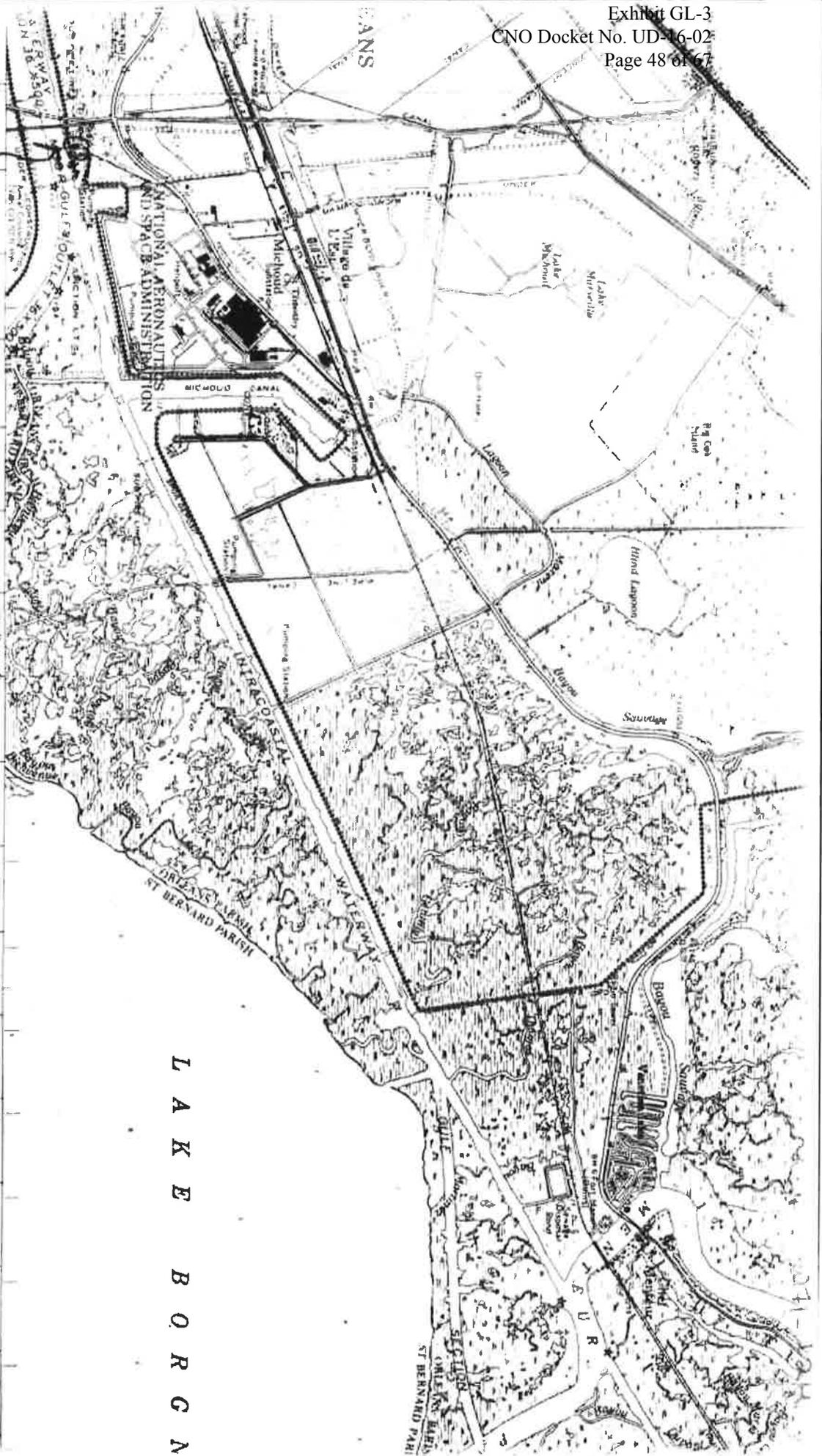
ABANDONED NOPSI WELL

Scale 1:62,500

Contour Interval 5 feet

DATUM IS MEAN SEA LEVEL

LAKE BORGN

ORLEANS PARISH
ST. BERNARD PARISH

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

MICHOUD CANAL

INTRACOASTAL WATERWAY

I.D.-300024087561701

WELL SCHEDULE

Owner No. *Michoud #2*   U.S. DEPT. OF THE INTERIOR   GEOLOGICAL SURVEY   Well No. *Or-125*
WATER RESOURCES DIVISION   LOUISIANA DISTRICT

CARD A (MASTER CARD)

Record by: *Balla, Whitman*   Date: *1/21/60, 10/15/69*   Source of data: *Owner*

State: *Louisiana* | 2 | 2 | County: *Orleans* | 3 | 6 |

Latitude: 3 0 0 0 2 4 N/S N   Longitude: 0 8 9 5 6 1 7   Sequential number: 4   Lat-long accuracy: 4

Local well number: 1 2 5   Township: 1 2 N/S S   Range: 1 3 E/W E   Section: 4 2

Local use: | | | | | | | | | | | | | Quadrangle: *Little Woods* 4 9 1 C

Owner: *New Orleans Public Service, Inc.* NEW ORLEANS PSI

Ownership: N   Use of water: E   Use of well: W   DATA AVAILABLE: Well data: 1   Frequency W/L meas.: I   Field aquifer characteristics:

Hyd. lab. data: 1   Q.W. data: P   Frequency sampling: I   Pumpage inventory: (yes) no   Period: 7   Aperture cards: yes   Log data: D

CARD B (WELL-DESCRIPTION CARD)

Boxes 1-19 same as on Card A   Well depth: Est. Rept. 6 3 2   Accuracy: 6   Depth cased (first perf.): 5 4 2

Casing type: *Steel*   Diam.: 1 6   Finish: 5   Method drilled: H   Date completed: 10/10/5 9 5 5

Driller: *Merge Pump & Machinery Co., Inc.*   Address: *New Orleans, La.*

Pump intake setting: 1 6 0   Lift type: T   Deep/Shallow: D   H.P. 150   Power type: W   Alt. LSD: *topo* | | | | 3

Other pump data: No. stages 5   Diam. 14   Column diam. 10   Ft piece length 10   Diam. 10   Capacity 1400 gpm against 350 ft. head

Alt. LSD accuracy: 3   MP description:

Water level: above/below MP; Ft (below) LSD *rept.* 7 3   Accuracy: 6   Date meas.: 8/22/59 8 5 9

Yield: 1 6 1 5   Method determined: 1   Drawdown: 6 7   Accuracy: 6   Pumping period: A

QUALITY OF WATER DATA: Iron | | Sulfate | | Chloride | | Hard. | |

Sp. Cond. | | Temp. 77 °F 7 7   Field pH | | Date sampled 10/15/64 0 6 4

CARD C (HYDROGEOLOGIC CARD)

Boxes 1-19 same as on Card A   Physiographic Province: *Coastal Plain* 0 3   Section: *Miss. Alluv. Plain* E

Drainage Basin: 1 4 E   Subbasin: | | Topography of well site: E

MAJOR AQUIFER: System *Quat* Q   Series *Pleist.* G   Aquifer, formation, or group 112 G&NO 7 N

Lithology *Sand* 5   Origin 3   Aquifer thickness 9 1 6

Length of well open to: 9 0   Depth to top of aquifer: 5 2 4

MINOR AQUIFER: System | | Series | | Aquifer, formation, or group | |

Lithology | | Origin | | Aquifer thickness | |

Length of well open to: | | | Depth to top of aquifer: | | |

Depth to consolidated rock: | | | | Source of data: | | Depth to basement: | | | | Source of data: | |

Surficial material: | | Infilt. char.: | | Coefficient of transmissibility: | | | Coefficient of Storage: | | | Card no.: | |

Or-125

CARD A✱(SUPPLEMENTAL CASING RECORD)

Boxes 1-19 same as on Card A

Diameter	Fract.	Type	Length	Depth to top
1 6		I	3 1 3	0
20 21	22	23	24 25 26 27	28 29 30 31
1 2		I	2 1 9	3 1 3
32 33	34	35	36 37 38 39	40 41 42 43
9 5		I	2 8	5 1 4
44 45	46	47	48 49 50 51	52 53 54 55
56	58	59	60 61 62 63	64 65 66 67

Other data: _____ 68 | 70 71 72 73 74 75 76 77

Card No.: 78   Card designation : | A | ✱ |
                  79 80

CARD B✱(SUPPLEMENTAL SCREEN RECORD)

Boxes 1-19 same as on Card A

Diameter	Fract.	Type	Length	Depth to top	Opening size
9 5		W	9 0	5 4 2	0 0 9
20 21	22	23	24 25 26	27 28 29 30	31 32 33
34 35	36	37	38 39 40	41 42 43 44	45 46 47
48 49	50	51	52 53 54	55 56 57 58	59 60 61
62 63	64	65	66 67 68	69 70 71 72	73 74 75

Other data: _____ 76 77

Card No. 78   Card designation: | B | ✱ |
                  79 80

CARD C✱(SUPPLEMENTAL YIELD AND SPECIFIC-CAPACITY DATA CARD)

Boxes 1-19 same as on Card A

Yield	Drawdown	Specific Capacity	Pump. per. (hrs)	Date meas.	
1 6 4 5	6 7 .	2 4 . 6		8/28/59	8 5 9
20 21 22 23	24 . 26 27 28	29 30 31 . 32	33 34 35		36 37 38
	.	.		Date meas.	
39 40 41 42	43 44 45 . 46 47	48 49 50 . 51	52 53 54		55 56 57
	.	.		Date meas.	
58 59 60 61	63 64 . 65 66	67 68 69 . 70	71 72 73		74 75 76

Card No.: 77 78   Card desig: | C | ✱ |
                  79 80

Boxes 1-19 same as on Card A

				Date meas.	
20 21 22 23	24 25 26 . 27 28	29 30 31 . 32	33 34 35		36 37 38
	.	.		Date meas.	
39 40 41 42	43 44 45 . 46 47	48 49 50 . 51	52 53 54		55 56 57
	.	.		Date meas.	
58 59 60 61	62 63 64 . 65 66	67 68 69 . 70	71 72 73		74 75 76

Card No.: 77 78   Card desig: | C | ✱ |
                  79 80

SKETCH AND DIAGRAM

CARD D ✳ (SUPPLEMENTAL WELL-DESCRIPTION CARD)

Boxes 1-19 same as on Card ✳A

Driller: M E N G E   P U M P   A N D   M A C H   C O
20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 /41 42 43 44

Test hole depth: 6 7 8   Pumpage: Hrs/day _____ Days/week ___ Weeks/year _____ Average rate _____
45 46 47 48   49 50   51   52 53   54 55 56 57

Accuracy ___ Pumpage year: _____ Coefficient of Permeability: _____ Field pH: _____ . ___
58   59 60 61   62 63 64 65   66 67 68

Lithologic samples available: ☑ Depth interval range: _____ to _____ Other data: _____
69   70 71 72 73   74 75 76 77   78

NOTES _Mch. Anal. by driller 524-620_____ Card designation: D ✳
79 80

LITHOLOGIC LOG

Lithology	Thickness	Depth	Aquifer or unit name
See yellow note scheduled for 2 cu.			

LITHOLOGIC LOG (cont.)

Lithology	Thickness	Depth	Aquifer or unit name

33-62

Owner No. **2**

Elevation **3±**

**UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY**

Well No. **Or-125**

Parish **Orleans**

Owner _New Orleans Public Service, Inc._   Address _317 Baronne St._ _New Orleans 9, La._

Location _Michoud Generating Station_   Sec. _42_, T. _12S_ R. _13E_

Driller _Menge Pump & Machinery Co., Inc_   Address _549 Dryades St._ _New Orleans 12, La._

Depth of test hole _678_ ft., Depth of well _633'8"_ f

Type of well: Dug, Driven, Bored, [Drilled,] Jet _____ Completed _10 Oct_ 19_

Stratigraphic unit _____ Log: [D.,] E., (W or C) _____

Casings: Kind _*T+C Galv. BA-2 Casing_ ;size _16" OD_ ;length _313-2_ ft.; between _0_ and _313-2_ f
   Kind _do._ ;size _12" OD_ ;length _219.0_ ft.; between _313-2_ and _532-2_ f
   Kind _____ ;size _9⅝ OD_ ;length _27-10_ ft.; between _514-4_ and _542-2_ f

Screen record (diam., opening, setting) _9⅝" OD -.009 Red Brass Screen_
50 + 60 mesh Standard Hardware — 542-2 to 632-2

Pump: Make and Type _F-M DWT_   Stages: No. _5_ , Diam. _14_
   Pump setting _160_ ft.; length and diameter of footpiece _10_ ft. _10_
   Capacity _1400 gpm @ 350' total head_ gpm; Column diameter _10_
   Power, kind: _Electric_   H.P. _150_   R.P.M. _1750_

Static level _73_ ft., (rep.), meas. _Aug 28 1960_, above (below) _____
   which is _at_ _____ ft. above, below land surf

Pumping level _157_ ft. Yield _1645_ gpm _Aug 28_ 195_

Drawdown _67_ ft. after pumping _10 min_ hours at _1645_ gpm _Aug 28_ 195

Specific capacity _24.6_ while pumping _1645 gpm Aug 28 1959_; Hrs/day in use ____

Use: [Ind.,] Irr., P.S., Dom., Stock, Obs., Test, _____
   Amount (gpd): Average _____, maximum _____, minimum _____

Quality _See Over_

   Odor _____ Sample _____ Date _____ 19_ Temp.(°F)_

Source of data _Correspondence New Orleans Public Service 19 Jan 60_

Recorded by _J R Rollo_ Date _21 Jan 60_ ;Rescheduled by _____ Date ____

Remarks: _* Casing cemented_
Mechanical Analyses by driller on back

Quadrangle _19HC_

(Revised May 1, 1958)

Well No. _Or-125_

Well No. Or-125

LOG OF WELL

Type of rock	Thickness	Depth
Top soil + sticky clay	10	10
Clay, sandy	6	16
Log	1	17
Clay, sandy	13	30
Sand, fine	26	56
Shale, sandy and shells	36	92
Shale, soft + streaks sand	93	185
Shale	140	325
Shale, sandy	35	360
Shale, sticky	20	380
Shale, sandy	11	391
Shale	54	445
Shale, sandy	30	475
Shale, hard and streaks sand	49	524
Sand, fine	16	540
Sand	80	620
Shale	58	678

27 Sept 56   FJ Hoffman

Color	Amber
Turbidity	None
Conductivity in OHMS @ 77°F	66.0
Total Dissolved Solids ppm	685
pH	8.3
Ammonia Nitrogen ppm	0.4
Total Chloride, as NaCl ppm	2
Total Alkalinity, as CaCO₃	340
Total Sulphates, as Na SO₄ ppm	Trace

Mechanical Analysis
% retained

Depth	.014	.012	.010	.008	Pa
524-540	0	0	11	37	5.
540-551	0	Trace	19	35	4.
551-563	0	Trace	26	24	5c
563-573	0	5	24	31	4.
573-585	Trace	21	32	28	9
585-596	5	19	30	25	21
596-608	Trace	18	33	37	22
608-620	0	15	38	28	19

SKETCH AND DIAGRAM

FIG 7M

NEW ORLEANS PUBLIC SERVICE INC.
MICHOUD STEAM ELECTRIC STATION

Punched + verified I.D. 3000260895611010 **WELL SCHEDULE**

Owner No. *Michoud #3*   U.S. DEPT. OF THE INTERIOR   GEOLOGICAL SURVEY   Well No. *Or-170*
                               WATER RESOURCES DIVISION   LOUISIANA DISTRICT

CARD A (MASTER CARD)

Record by: *J. R. Rollo*   Date: *5-17-62*   Source of data: *Observations, C. M. Weber*

State: *Louisiana* | 2 | 2 | County: *Orleans* | 3 | 6 |

Latitude: | 3 | 0 | 0 | 0 | 2 | 6 | Ⓝ | N | Longitude: | 0 | 8 | 9 | 5 | 6 | 1 | 1 | Sequential number: | 1 | Lat-long accuracy: | 1 |

Local well number: | | 1 | 7 | 0 | | Township: | 1 | 2 | Ⓢ | Range: | 1 | 3 | Ⓔ | Section: | | 4 | 2 |

Local use: | | | | | | | | | | | | | | Quadrangle: *Little Woods* | 1 | 9 | 1 | C |

Owner: *New Orleans Public Service, Inc.* N|E|W| |O|R|L|E|A|N|S| |P|S|I

Ownership: | N | Use of water: | E | Use of well: | W | DATA AVAILABLE: Well data: | 3 | Frequency W/L meas.: | Ø | Field aquifer characteristics: | |

Hyd. lab. data: | | Q.W. data: | P | Frequency sampling: | I | Pumpage inventory: (no) yes Period: | | Aperture cards: yes Log data: | D | E |

CARD B (WELL-DESCRIPTION CARD)

Boxes 1-19 same as on Card A   Well depth: *645* Est. Rept.: | 6 | 4 | 5 | Accuracy: | 2 | Depth cased (first perf.): | 5 | 3 | 0 |

Casing type: _____ Diam.: | 1 | 3 | Finish: | S | Method drilled: | H | Date completed: *6-62* | 7 | 6 | 2 |

Drillee: *Layne La. G.*   Address: *L.A. Harvey*

Pump intake setting: *200* | 2 | 0 | 0 | Lift type: | T | Deep/Shallow: | 2 | H.P. *200* Power type: | N | Alt. LSD: *3* | | | | 3 |

Other pump data: No. stages *4* Diam. *15* Column diam. *10* Ft piece length *20* Diam. *10* Capacity *1400* gpm against *400* ft. head

Alt. LSD accuracy: | 3 | MP description: *Top of Casing, 3.0 FT. Above LSD.*

Water level: *75.20* above below MP Ft above below LSD *72.20* | | | 7 | 2 | Accuracy: | A | Date meas.: *7-11-62* | 7 | 6 | 2 |

Yield: *2020* | 2 | 0 | 2 | 0 | Method determined: | | Drawdown *49.10* | | 4 | 9 | Accuracy: | 6 | Pumping period: | | | C |

QUALITY OF WATER DATA: Iron ___ | | Sulfate ___ | | Chloride ___ | | Hard. ___ | |

Sp. Cond. ___ | | Temp. ___ °F | | | Field pH ___   Date sampled ___ | | |

CARD C (HYDROGEOLOGIC CARD)

Boxes 1-19 same as on Card A   Physiographic Province: *Coastal plain* | 0 | 3 | Section: *Miss. Alluvial Plain* | E |

Drainage Basin: *Lower Mississippi* | 1 | 4 | F | Subbasin: ___ | | Topography of well site: | F |

MAJOR AQUIFER: System *Quat* | Q | Series *Pleist* | G | Aquifer, formation, or group *"700-ft" Sand* | 7 | N |

Lithology *Sand* | S | Origin | | Aquifer thickness *115* | 1 | 1 | 5 |

Length of well open to: *115* | 1 | 1 | 5 | Depth to top of aquifer: *525* | 5 | 2 | 5 |

MINOR AQUIFER: System | | Series ___ | | Aquifer, formation, or group ___ | | |

Lithology ___ | | | Origin | | Aquifer thickness ___ | | |

Length of well open to: ___ | | | Depth to top of aquifer: ___ | | |

Depth to consolidated rock: ___ | | | | Source of data: | | Depth to basement: ___ | | | | Source of data: | |

Surficial material: | | | Infilt. char.: | | Coefficient of transmissibility: ___ | | | Coefficient of Storage: ___ | | | Card no.: | |

CARD ZA (SUPPLEMENTAL CASING RECORD)

Boxes 1–19 same as on Card A

Diameter	Fract.	Type	Length	Depth to top
16			3 0 3	0
14			2 1 7	3 0 3
9 5			8 7	4 4 3

Other data: ____

Card designation: Z A   Card No.: ☐

CARD ZB (SUPPLEMENTAL SCREEN RECORD)

Boxes 1–19 same as on Card A

Diameter	Fract.	Type	Length	Depth to top	Opening size
9 5			1 5	5 3 0	

Other data: ____

Card designation: Z B   Card No.: ☐

CARD ZC (SUPPLEMENTAL YIELD AND SPECIFIC-CAPACITY DATA CARD)

Boxes 1–19 same as on Card A

STEP-DRAWDOWN TEST

Yield	Drawdown	Specific Capacity	Pump. per. (hrs)	Date meas.	
1404	30.0	47.0	B	6-20-62	662
1613	36.8	43.8	B	6-20-62	662
1711	40.0	42.8	B	6-20-62	662

Card designation: Z C   Card No.: 1

Boxes 1–19 same as on Card A

Yield	Drawdown	Specific Capacity	Pump. per. (hrs)	Date meas.	
1809	43.2	41.9	B	6-20-62	662
1910	45.8	41.7	B	6-20-62	662
2020	49.1	41.1	D	6-20-62	662

Card designation: Z C   Card No.: 2

SKETCH AND DIAGRAM

SEE SKETCH Or-124

CARD ZD (SUPPLEMENTAL WELL-DESCRIPTION CARD)

Boxes 1-19 same as on Card A

Driller: L A Y N E | L O U I S I A N A | C O
20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44

Test hole depth: 6 6 6
45 46 47 48

Pumpage: Hrs/day [ ]
49 50

Days/week [ ]
51

Weeks/year [ ]
52 53

Average rate [ ]
54 55 56 5

Accuracy [ ]
58

Pumpage year: _____

[ ][ ][ ]
59 60 61

Coefficient of Permeability: _____

[ ][ ][ ][ ]
62 63 64 65

Field pH: [ ][ ]
66 67 6

Lithologic samples available: yes [N]
69

Depth interval range: [ ][ ][ ][ ]
70 71 72 73

to [ ][ ][ ][ ]
74 75 76 77

Other data: _____

Card designation: [Z][C]
79 8

NOTES _34" underream — gravel wall_
Grain-size anal (by driller) n file

periodic WQ data

LITHOLOGIC LOG

Lithology	Thickness	Depth	Aquifer or unit name
see "Well 3 test — Public Service" files for o-ru			

LITHOLOGIC LOG (cont.)

Lithology	Thickness	Depth	Aquifer or unit name

I.D. 300030089561801   **WELL SCHEDULE**

Owner No. _Michoud #4_   U.S. DEPT. OF THE INTERIOR   GEOLOGICAL SURVEY   Well No. _Or-171_
      WATER RESOURCES DIVISION   LOUISIANA DISTRICT

PUNCHED and VERIFIED
ROLLA COMPUTATION BRANCH

CARD A (MASTER CARD)

Record by: _Rollo, Whitman_   Date: _3/7/63, 10/15/69_   Source of data: _(Webr(term))_

State: _Louisiana_ | 2 2 | County: _Orleans_ | 3 6 |
     1 2   3 4

Latitude: |3 0 0 0 3 0| N/S |N| Longitude: |0 2 9 5 6 1 8| Sequential number |1| Lat-long accuracy |4|
   5 6 7 8 9 10   11   12 13 14 15 16 17 18   19   20

Local well number: |1 7 1| seq |1| Township: |1 2| N/S |S| Range: |1 3| E/W |E| Section: |4 2|
   21 22 23 24   25   26 27   28   29 30   31   32 33 34

Local use: |_|_|_|_|_|_|_|_|_|_|_|_|_| Quadrangle: _Little Woods_ |1 9| |C|
   35 36 37 38 39 40 41 42 43 44 45 46 47   48 49 50   51

Owner: _New Orleans Public Service Inc._ |N E W| |O R L E A N S| |P S I|
                                52 53 54 55/56   57 58 59 60 61 62 63   64 65 66

Ownership: |N| Use of water: |E| Use of well: |W| DATA AVAILABLE: Well data: |1| Frequency W/L meas.: |I| Field aquifer characteristics: |_|
   67   68   69   70   71   72

Hyd. lab. data: |_| Q.W. data: |P| Frequency sampling: |I| Pumpage inventory: (yes)/no   Period: |2| Aperture cards: yes |_| Log data: |D E|
   73   74   75   76   77   78 79

CARD B (WELL-DESCRIPTION CARD)

| Boxes 1-19 same as on Card A | Well depth: Est. Rept. |6 4 5| Accuracy: |3| Depth cased (first perf.): |5 3 0|
                                     20 21 22 23   24   25 26 27 28

Casing type: _Steel_   Diam.: |1 6| Finish: |S| Method drilled: |R| Date completed: _8/17/62_ |9 6 2|
             29 30   31   32   33 34 35

Driller: _Layne Louisiana Company_   Address: _Lake Charles, La._

Pump intake setting: |2 0 0| Lift type: |T| Deep; Shallow: |D| H.P. _200_ Power type: |W| Alt. LSD: _top_ |_|_|_|_| 3|
                     36 37 38   39   40   41   42 43 44 45 46

Other pump data: No. stages _4_ Diam. _15_ Column diam. _10_ Ft piece length _20_ Diam. _10_ Capacity _1400_ gpm against _400_ ft. head

Alt. LSD accuracy: |3| MP description: _____
   47

Water level: _____ above/below MP; Ft (below)/above LSD _rept_ |_|_|_|_2| Accuracy: |6| Date meas.: _3/5/63_ |2 6 3|
                                          48 49 50 51   52   53 54 55

Yield: |1 7 4 0| Method determined: |_| Drawdown: _32.5_ |3 8| Accuracy: |6| Pumping period: |_|_|_|
      56 57 58 59 60   61   62 63 64   65   66 67 68

QUALITY OF WATER DATA: Iron |_| Sulfate |_| Chloride |_| Hard. |_|
                              69   70   71   72

Sp. Cond. |_| Temp. °F |_|_|_| Field pH |_| USGS Part Date sampled _6/9/69_ |6 6 9|
          73   74 75 76   77 78 79

CARD C (HYDROGEOLOGIC CARD)

| Boxes 1-19 same as on Card A | Physiographic Province: _Coastal Plain_ |0 3| Section: _Miss. Aluv. Plain_ |E|
                                            20 21   22

Drainage Basin: |1 4| |E| Subbasin: |_| Topography of well site: |F|
                23 24   25   26   27

MAJOR AQUIFER: System _Quat._ |Q| Series _Pleist_ |G| Aquifer, formation, or group _"700-foot"_ |7 N|
                        28   29   30 31

Lithology _Sand_ |S| Origin |3| Aquifer thickness |1 3 1|
                   32 33   34   35 36 37

Length of well open to: |1 1 5| Depth to top of aquifer: |5 2 4|
                     38 39 40   41 42 43

MINOR AQUIFER: System |_| Series |_| Aquifer, formation, or group |_|
                        44   45   46 47

Lithology |_| Origin |_| Aquifer thickness |_|
                   48 49   50   51 52 53

Length of well open to: |_|_|_| Depth to top of aquifer: |_|_|_|
                     54 55 56   57 58 59

Depth to consolidated rock: |_|_|_| Source of data: |_| Depth to basement: |_|_|_| Source of data: |_|
                          60 61 62 63   64   65 66 67 68   69

Surficial material: |_|_| Infilt. char.: |_| Coefficient of transmissibility: |_|_|_| Coefficient of Storage: |_|_|_| Card no.: |_|
                70 71   72   73 74 75   76 77 78   79

CARD A✳(SUPPLEMENTAL CASING RECORD)

Boxes 1-19 same as on Card A

Diameter	Fract.	Type	Length	Depth to top
1 6 (20 21 22)	5 (23)	(24 25) 3 0 3 (26 27)	(28 29 30) 0 (31)	
1 4 (32 33 34)	5 (35)	(36 37) 2 1 7 (38 39)	3 0 3 (40 41 42 43)	
9 5 (44 45 46)	5 (47)	(48 49) 8 3 (50 51)	4 4 7 (52 53 54 55)	
(56 57)	(58 59)	(60 61 62 63)	(64 65 66 67)	

Other data: (68 69 70 71 72 73 74 75 76 77)

Card No.: (78) Card designation : | A | ✳ |
(79) (80)

CARD B✳(SUPPLEMENTAL SCREEN RECORD)

Boxes 1-19 same as on Card A

Diameter	Fract.	Type	Length	Depth to top	Opening size
9 5 (20 21 22)	5 (23)	(24 25) 1 1 5 (26)	(27 28 29 30) 5 3 0	(31 32 33)	
(34 35 36)	(37)	(38 39 40)	(41 42 43 44)	(45 46 47)	
(48 49 50)	(51)	(52 53 54)	(55 56 57 58)	(59 60 61)	
(62 63 64)	(65)	(66 67 68)	(69 70 71 72)	(73 74 75)	

Other data: _____ (76 77)

Card No. (78) Card designation: | B | ✳ |
(79) (80)

CARD C✳(SUPPLEMENTAL YIELD AND SPECIFIC-CAPACITY DATA CARD)

Boxes 1-19 same as on Card A

Yield	Drawdown	Specific Capacity	Pump. per. (hrs)		
1 7 4 0 (20 21 22 23)	3 8 . 5 (24 26 27 28)	4 5 . 2 (29 30 31 32)	(33 34 35)	Date meas. 2/5/63	2 6 3 (36 37 38)
(39 40 41 42)	(43 44 45 . 46 47)	(48 49 50 . 51)	(52 53 54)	Date meas. _____	(55 56 57)
(58 59 60 61)	(63 64 . 65 66)	(67 68 69 . 70)	(71 72 73)	Date meas. _____	(74 75 76)

Card No.: (77 78) Card desig : | C | ✳ |
(79) (80)

Boxes 1-19 same as on Card A

(20 21 22 23)	(24 25 26 . 27 28)	(29 30 31 . 32)	(33 34 35)	Date meas. _____	(36 37 38)
(39 40 41 42)	(43 44 45 . 46 47)	(48 49 50 . 51)	(52 53 54)	Date meas. _____	(55 56 57)
(58 59 60 61)	(62 63 64 . 65 66)	(67 68 69 . 70)	(71 72 73)	Date meas. _____	(74 75 76)

Card No.: (77 78) Card desig: | C | ✳ |
(79) (80)

SKETCH AND DIAGRAM

CARD D✳(SUPPLEMENTAL WELL-DESCRIPTION CARD)

Boxes 1-19 same as on Card 'A

Driller: L A Y N E   L O U I S I A N A   C O M P A N Y
20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44

Test hole depth: 1 6 6 5
45 46 47 48

Pumpage: Hrs/day __ __   Days/week __   Weeks/year __ __   Average rate __ __ __ __
49 50   51   52 53   54 55 56 57

Accuracy __   Pumpage year: _____ __ __ __
58   59 60 61

Coefficient of Permeability: _____ __ __ __ __
62 63 64 65

Field pH: __ __ . __
66 67 68

Lithologic samples available: N
69

Depth interval range: __ __ __ __   to   __ __ __ __   Other data: _____ __
70 71 72 73   74 75 76 77   78

NOTES _____   Card designation: D ✳
79 80

LITHOLOGIC LOG

Lithology	Thickness	Depth	Aquifer or unit name
See yellow tab and attached	/	~ ~	

LITHOLOGIC LOG (cont.)

Lithology	Thickness	Depth	Aquifer or unit name

33-62

LOUISIANA DEPARTMENT OF TRANSPORTATION AND DEVELOPMENT
OFFICE OF PUBLIC WORKS
WATER-WELL REGISTRATION (State Act 535 (1972))

(Check Appropriate Boxes)
If well is new does it replace an existing well? YES ☒ NO ☐   Is well gravel-packed? YES ☒ NO ☐   JAN. 0 7 1983

Form Completed By:
Menge
Name
P.O. Box 8210, Metairie, La.
Signature

1. Well Owner: New Orleans Public Service, Inc.

   Address: 317 Baronne Street

   New Orleans, La.   70112

   Owner's Well Number or Name (If Any)   #8

2. LOCATION OF WELL   Parish: Orleans   Section: 42, Township: 12S

   Range: 13E   Well is Near, ____ Approximately ____ miles from

   Well at Michoud Generating Station – Old Gentilly & Parish Road
   (Crossroads, Town, City, Railroad, A-, ___)

3. WELL INFORMATION   Ground Elevation ____   M.S.L. Depth of Hole 637 ft
   Diameter of Hole 20   Depth of Completion Well 633.1 ft
   Date Completed 12/15/82   By

   (Give Name and Address of Water Well Contractor) Menge Well & Pump Co.
   P. O. Box 8210, Metairie, La.   70011

4. CASING AND SCREEN INFORMATION:
   CASING TYPE ASTM A53 Grade B   SCREEN: TYPE HSC S.S. pipe base
   16 in from 0 ft to 533.8 ft   10 in from 535.1 ft to 631.15 ft
   ___ in from ___ ft to ___ ft   ___ in from ___ ft to ___ ft
   ___ in from ___ ft to ___ ft   ___ in from ___ ft to ___ ft
   Extension Pipe 10 in from 447.2 ft to 535.1 ft.
   Give details on size and length of casing cemented and method used to cement. 100% cement
   coverage-through pipe method by Halliburton

5. WATER LEVEL AND YIELD INFORMATION: On 12/15/82 the static water level in well was 149'
   ft. ☒ below ☐ above top casing   How determined?
   electric sounder   The well yielded 1600 gpm with a draw down of
   135 ft. after one hours of continuous pumping on (date) 12/15/82 Describe how yield was
   measured orrifice   It is planned to pump the well at
   a rate 1600 gpm for 24 hours per day for 365 days per year Proposed average daily
   pumping rate: ____ gallons Motor HP. 300 Pump setting. 380 ft.

6. USE OF WELL (Check Appropriate Box)
   Irrigation/Agricultural ☐   Industrial ☐   Public Supply ☐   Domestic/Rural ☐   Power Generation ☒
   (If industrial or public supply is checked please see bottom of this form)
   OTHER (Please Specify)

7. AVAILABLE INFORMATION (Check Appropriate Boxes)
	YES	NO
Is an electrical log or other borehole geophysical log available?	☐	☒ (If yes, please attach a copy of log)
Is a driller's log available? (Complete bottom of form)	☒	☐
Is a mechanical analysis of the drill cuttings available?	☒	☐
Is a chemical analysis of water available?	☐	☒
Is a biological or bacteriological analysis available?	☐	☒
Are aquifer test results available?	☐	☒

8. ABANDONMENT INFORMATION:
   If this is a replacement well has owner been informed by contractor of need to plug abandoned well?   YES ☒ NO ☐
   Has the owner been informed of state regulations requiring the plugging and(or) sealing of all abandoned wells?   YES ☒ NO ☐

9. REMARKS (Such as engineer, pump information, acreage irrigated, etc.)

10. DRILLER'S LOG (Description and color of cuttings, such as, shale, sand, etc. in feet below ground level)

FROM	TO	DESCRIPTION	FROM	TO	DESCRIPTION	FROM	TO	DESCRIPTION
0	10	Top soil	360	462	Sandy Shale			
10	18	Clay	462	479	Sand			
18	102	Sand & Sandy Clog	479	529	Sandy Shale			
102	180	Sandy, Shale	629	535	Fine Sand			
180	302	Shale	535	631.5	Med. Sand			
302	360	Sticky Shale	631.5	637	Shale			

(If necessary, continue log on back of original form.)

DO NOT USE—OFFICE USE ONLY

STATE	PARISH	LOCAL WELL NO.
2 2	0 7 1	- 2 0 8

IDENTIFICATION NUMBER
3 0 0 0 3 0 8 9 5 6 1 5 0 1

OWNER NAME
NEW ORLEANS PSI

WELL DEPTH 6 3 1 Ft   Use of Well E   - -

Date Completed 1 2 8 2   OWNER'S NO. 8

Geologic Unit 1 1 2 6 7 M O

Proposed Daily Pumping Status 2 3 0 4 0 0 0

AVAILABLE INFORMATION
L I D

Additions, Changes or Deletions   Card No. 1

REFER TO INSTRUCTION FOR CODES
Coded By M. STACK on 7-3-84
Location Verified On 7-3-84
By M. STACK
The Correct Location is

Remarks MENGE PUMP
42 T12S R13E
QUAD 191

Copy of Registration Form to USGS ☐ ☐
Copy of Form to Water Comm. ☐ ☐

PUBLIC SUPPLY: (If well is for public supply purpose please check one of the following to indicate principal category of public supply use.)
☐ Municipal   ☐ Therapeutic
☐ Rural   ☐ Institutional/Government
☐ Commercial   ☐ Other ____ Specify

INDUSTRIAL: (If well is for industrial purpose please check one of the following to indicate the standard industrial category representing the principal industrial use)
☐ Food and Kindred Products   ☐ Paper and Allied Products
☐ Textile Mill Products   ☐ Chemicals and Allied Products
☐ Lumber & Wood Products (Except Furniture)   ☐ Petroleum Refining & Related Industries
☐ Other ____   ☐ Primary Metal Products

LOPW-GW-1(R 1/78)

STATE OF LOUISIANA
DEPARTMENT OF TRANSPORTATION AND DEVELOPMENT
OFFICE OF PUBLIC WORKS
ENGINEERING DIVISION

JUL 1 2 1984

DPW 24   Page No.

| PARISH ORLEANS | COMPUTED BY | DATE |
| SUBJECT New Orleans Public Service | CHECKED BY M. STACK | DATE 7-2-84 |

WATER WELL LOCATION

OLD GENTILLY ROAD.

N

PARIS RD.

±1500'

N.O.P.S.I.
PLANT

MAIN BUILDING
& CONTROL ROOM

SERVICE ROAD

±1000'

WELL

O4-208

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

ORLANDO TODD

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JULY 2017

TABLE OF CONTENTS

EXHIBIT LIST

Exhibit OT-1R   Revised CT Estimated First-Year Non-Fuel Revenue Requirement

Exhibit OT-2   Alternative Peaker Estimated First-Year Non-Fuel
                       Revenue Requirement

1		**I.** <u>**INTRODUCTION**</u>
2	Q1.	PLEASE STATE YOUR NAME, TITLE AND CURRENT BUSINESS ADDRESS.
3	A.	My name is Orlando Todd. I am the Finance Director for Entergy New Orleans, Inc.
4		("ENO" or the "Company"). My business address is 1600 Perdido Street, New
5		Orleans, Louisiana 70112.
6		
7	Q2.	ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?
8	A.	I am testifying on behalf of ENO.
9		
10	Q3.	ARE YOU THE SAME ORLANDO TODD THAT FILED DIRECT TESTIMONY
11		IN THIS PROCEEDING?
12	A.	Yes.
13		
14	Q4.	WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL AND AMENDING
15		DIRECT TESTIMONY?
16	A.	My Supplemental and Amending Direct Testimony ("Supplemental Direct
17		Testimony") supports the Supplemental and Amending Application ("Supplemental
18		Application") in this proceeding, which seeks, among other things, approval to
19		construct the New Orleans Power Station ("NOPS"), which will consist of either a
20		combustion turbine ("CT") resource with a summer capacity of 226 megawatts
21		("MW"), or alternatively, seven Wärtsilä 18V50SG Reciprocating Internal
22		Combustion Engine ("RICE") Generator sets ("Alternative Peaker"). My testimony
23		here supports the application by providing the estimated first-year revenue

1   requirement of the Alternative Peaker and ENO's proposed rate recovery plan, as

2   well as updating the first-year revenue requirement of the proposed CT that was

3   originally provided in my direct testimony offered in this proceeding.

4

5   **II.   ESTIMATED FIRST-YEAR NON-FUEL REVENUE**
6   **REQUIREMENT FOR BOTH NOPS OPTIONS**

7   Q5. PLEASE PROVIDE AN OVERVIEW OF THE INCREMENTAL COSTS AND

8   REVENUES ASSOCIATED WITH THE ALTERNATIVE PEAKER.

9   A. For purposes of my testimony, the incremental costs associated with the Alternative

10   Peaker will fall within two broad categories that I discussed in my direct testimony:

11   non-fuel costs, such as operations and maintenance expense ("O&M") and capital

12   investment, that is, the cost to construct the Project; and (2) fuel expense and any

13   revenue or expense resulting from Midcontinent Independent System Operator, Inc.

14   ("MISO") market settlements.

15

16 Q6. HOW WAS THE ESTIMATED RATE BASE FOR THE ALTERNATIVE PEAKER

17   DETERMINED?

18 A. The first step in the process is the derivation of the rate base for the Project during the

19   first year of service, which is derived on Page 2 of Exhibit OT-2. As may be seen,

20   the starting point is the estimated total construction cost including Allowance for

21   Funds Used During Construction ("AFUDC") of approximately $210.0 million,

22   which estimate is discussed in detail by Company witness Jonathan E. Long. This

23   value constitutes the plant in service amount on the first day of operation. During the

1   first year of operation, depreciation expense at the rate of 3.3% per year will be

2   accrued in the amount of approximately $7.0 million, giving rise to an accumulated

3   reserve for depreciation in that amount. The final component of rate base is the

4   deduction for accumulated deferred income taxes ("ADIT"), which arises due to

5   timing differences between book straight-line depreciation and accelerated tax

6   depreciation. The end result is a total Alternative Peaker rate base of approximately

7    $179.3 million at the end of the first year following commercial operation.

8

9   Q7.   WHY DID ENO USE A DEPRECIATION RATE OF 3.3% FOR THE ESTIMATED

10   REVENUE REQUIREMENT?

11   A.   The Direct Testimony of Mr. Jonathan Long contains the basis for the 3.3%

12   depreciation rate used for the CT.   For the same reasons, ENO believes this

13   depreciation rate is appropriate to use for the Alternative Peaker.

14

15   Q8.   DID THE COMPANY USE THE SAME WEIGHTED AVERAGE COST OF

16   CAPITAL ("WACC") USED IN THE ESTIMATED FIRST-YEAR REVENUE

17   REQUIREMENT   OF   THE   CT   TO   CALCULATE   THE   REVENUE

18   REQUIREMENT OF THE ALTERNATIVE PEAKER?

19   A.   Yes. As discussed later in my testimony, ENO intends to use its WACC, including its

20   actual capital structure, at the time the Project commences commercial operation for

21   interim cost recovery purposes.

22

1   Q9.   WHAT IS THE BASIS FOR THE ESTIMATED O&M FOR THE ALTERNATIVE

2   PEAKER SHOWN IN EXHIBIT OT-2?

3   A.   The basis of the estimated O&M is the estimate attached to the Supplemental and

4   Amending Direct Testimony of Company witness Robert A. Breedlove.   The

5   estimated O&M used in the first-year non-fuel revenue requirement does not include

6   Long-Term Service Agreements ("LTSA") costs, as the Company has not yet made a

7   determination regarding the feasibility of entering into an LTSA if the Alternative

8   Peaker unit is selected by the Council.

9

10   Q10.   WERE PROPERTY TAXES ESTIMATED IN THE SAME MANNER AS FOR

11   THE CT?

12   A.   Yes. Property taxes were assumed to be zero because the Project would be subject to

13   a property-tax exemption.

14

15   Q11.   PLEASE SUMMARIZE THE ESTIMATED FIRST-YEAR NON-FUEL REVENUE

16   REQUIREMENT FOR THE ALTERNATIVE PEAKER.

17   A.   The estimated first-year non-fuel revenue requirement for the alternative peaker is

18          $34.4 million. This estimated amount assumes the construction cost of the Project,

19   including AFUDC, totals $210.0 million.

20

1   Q12.   HAVE THERE BEEN ANY CHANGES TO THE ESTIMATED COST OF THE CT

2   THAT ENO ORIGINALLY PROPOSED FOR THE NOPS?

3   A.   Yes. As discussed in the supplemental direct testimony of Mr. Jonathan Long, the

4   estimated capital investment necessary to complete the CT has increased.

5

6   Q13.   HAS ENO FACTORED THE CHANGE IN THE ESTIMATE INTO ITS

7   CALCULATION OF THE FIRST-YEAR REVENUE REQUIRED FOR THE CT?

8   A.   Yes. Exhibit OT-1R reflects the updated first-year revenue requirement as a result of

9   the increase in the capital costs of the CT. The estimated O&M included in the first-

10   year revenue requirement has not changed.

11

12   **III.**   **PROPOSED COST RECOVERY PLAN**

13   Q14.   WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

14   A.   In this section of my testimony, I discuss how the Company proposes to recover the

15   costs associated with the Alternative Peaker, as the cost recovery plan for the CT has

16   not changed.

17

18   Q15.   HAVE THE COMPANY'S REGULATORY ASSUMPTIONS CHANGED

19   REGARDING RATEMAKING IN EFFECT WHEN THE PROJECT BEGINS

20   COMMERCIAL OPERATION?

21   A.   No. The Company expects, if selected by the Council, the CT would commence

22   commercial operation by November 2020, or the Alternative Peaker in October 2019.

23   In either circumstance, the Company still expects that the Combined Rate Case

1   described in Paragraph 8 of the Algiers Transaction Agreement in Principle approved

2   in Council Resolution R-15-194, dated May 14, 2015, will have been completed with

3   all of ENO's customers subject to a single set of Council-approved base rates and

4   riders.[1] Also, the Company expects that the recovery of the capacity costs associated

5   with the Ninemile 6 Unit and associated with Union Power Station Power Block 1

6   will have been realigned from the Purchased Power and Capacity Acquisition Cost

7   Recovery Rider ("PPCACR Rider") to base rates. Finally, the Company expects that

8   ENO will be subject to a formula rate plan ("FRP") following the Combined Rate

9   Case. These are the principal regulatory assumptions that are the context for ENO's

10   proposed cost recovery plan.

11

12 Q16. IS THE COMPANY'S PROPOSAL TO RECOVER THE NON-FUEL REVENUE

13   REQUIREMENT OF THE ALTERNATIVE PEAKER DIFFERENT THAN ITS

14   PROPOSAL FOR THE CT?

15 A.   No. ENO proposes that the first-year non-fuel revenue requirement associated with

16   the Alternative Peaker initially (first twelve months) be recovered contemporaneous

17   with commercial operation of the Project through the PPCACR Rider, which would

18   be modified for such purpose, or a similar exact cost recovery rider. This rider would

19   use the Company's WACC, including its actual capital structure, at the time the

20   Project commences commercial operation to determine the return on the Company's

---

[1]   Currently, the Company serves electric customers in the Fifteenth Ward of the City of New Orleans, that is,
Algiers, using base rates approved in Council Docket No. UD-13-01, when Entergy Louisiana, LLC served
these customers. The Company serves electric customers outside of Algiers using base rates resulting from
Council Docket No. UD-08-03 and subsequent formula rate plan proceedings.

1 investment in the Project, and the return on equity authorized by the Council as a

2 result of the Combined Rate Case. The non-fuel revenue requirement would be

3 recovered from all of the Company's customers, including Algiers customers, which

4 today do not pay charges pursuant to the PPCACR Rider.

5   Following the initial twelve-month's dollar-for-dollar recovery, the Project's

6 non-fuel revenue requirement would be realigned so as to be recovered through the

7 FRP Rate Adjustment.

8

9 Q17. IS IT IMPORTANT TO ENO'S FINANCIAL CONDITION THAT ENO

10   RECEIVES TIMELY RECOVERY OF THE ALTERNATIVE PEAKER'S NON-

11   FUEL REVENUE REQUIREMENT?

12 A. Yes. As I explained in my Direct Testimony in this proceeding with respect to the

13   CT, once a project commences commercial operation, ENO will begin incurring costs

14   that are not expected to be reflected in ENO's base rates until the project is placed in

15   service. If the Council takes no action to address these costs, then those expenditures

16   will have a significant adverse effect on ENO's financial condition.

17   For example, assuming an October 2019 commercial operation date for the

18   Alternative Peaker, ENO will begin to incur depreciation and O&M expenses related

19   to the Project in October 2019. Without timely rate recovery, *i.e.*, contemporaneous

20   in-service rate recovery, ENO will not begin to recover any depreciation and O&M

21   expenses until the next rate change, which under an assumed FRP may not be until

22   the third quarter of 2020. Similarly, the Company would not be recovering any return

1   on the Project during this same period. This approximate twelve-month delay in

2   recovery would have a detrimental effect on ENO's financial condition and metrics.

3

4   Q18.   WILL THE ESTIMATED FIRST-YEAR NON-FUEL REVENUE REQUIREMENT

5   BE UPDATED PRIOR TO COMMERCIAL OPERATION?

6   A.   Yes. Irrespective of which alternative the Council authorizes, the Company proposes

7   that the estimated first-year non-fuel revenue requirement be updated and a revised

8   PPCACR Rider or a similar exact cost recovery rider be filed with the Council on or

9   about 60 days prior to the anticipated start of commercial operation.

10

11   Q19.   HOW WOULD THESE COSTS BE RECOVERED IF THERE IS NO FRP IN

12   PLACE AFTER THE COMBINED RATE CASE?

13   A.   ENO proposes that the selected project's non-fuel revenue requirement be recovered

14   through the PPCACR Rider or a similar exact cost recovery rider until such time that

15   ENO's base rates are reset.

16

17   Q20.   AT THIS TIME, DOES THE COMPANY ANTICIPATE ENTERING INTO AN

18   LTSA FOR THE ALTERNATIVE PEAKER?

19   A.   As I mentioned earlier in my testimony, ENO has not determined whether it is cost

20   beneficial to enter into an LTSA for the Alternative Peaker. However, if the

21   Company does enter into an LTSA before the commencement of commercial

22   operations, similar to its proposal for the CT, the Company proposes that the LTSA

23   expenses be recovered through the fuel adjustment clause ("FAC"). Such an LTSA

1   would likely require payment for certain major maintenance activities, with such

2   payments varying based on the utilization of the resource, including the number of

3   unit starts and hours of run-time. The variable nature of these expenses makes them

4   appropriate for recovery through the Company's FAC. FAC recovery is appropriate

5   as it will ensure that customers pay the actual LTSA costs when such costs are

6   actually incurred.   Recovering these costs through base rates gives rise to the

7   possibility that the Company would recover amounts greater or less than the actual

8   costs incurred.

9

10   Q21. IF ANY MAINTENANCE COSTS ARE INCURRED ON A NON-VARIABLE OR

11   TRANSACTIONAL BASIS, IS ENO PROPOSING TO RECOVER SUCH

12   EXPENSES THROUGH THE FAC?

13   A.   No. ENO would anticipate that any fees for maintenance outside of the base scope of

14   work of a potential LTSA would require negotiation of a separate contract or work

15   order. Such fees would be recovered through base rates.

16

17   Q22. IS ENO'S PROPOSED RECOVERY OF MISO-RELATED REVENUES AND

18   EXPENSES FOR THE ALTERNATIVE PEAKER DIFFERENT THAN THAT

19   PROPOSED BY ENO FOR THE CT?

20   A.   No. Regardless of what alternative is selected, ENO proposes that the MISO market

21   settlement revenues and expenses associated with the Alternative Peaker, except

22   those falling in the Administration accounting category, should be included in the

23   Company's FAC. Any revenues or expenses falling in the Administration accounting

1   category would be recovered through ENO's MISO Cost Recovery Rider. This

2   treatment is consistent with the currently-approved treatment of those MISO market

3   settlement revenues and expenses attributable to other ENO resources.

4

5   Q23.   WILL THE ENVIRONMENTAL ADJUSTMENT CLAUSE ("EAC") INCLUDE

6   EXPENSES ASSOCIATED WITH THE PROJECT?

7   A.   It may, if emission allowances are required to operate the Project.

8

9   Q24.   DOES THIS CONCLUDE YOUR SUPPLEMENTAL AND AMENDING DIRECT

10   TESTIMONY?

11   A.   Yes.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

      NOW BEFORE ME, the undersigned authority, personally came and appeared, **ORLANDO TODD**, who after being duly sworn by me, did depose and say:

      That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

_____
Orlando Todd

SWORN TO AND SUBSCRIBED BEFORE ME
THIS _____ DAY OF JUNE, 2017
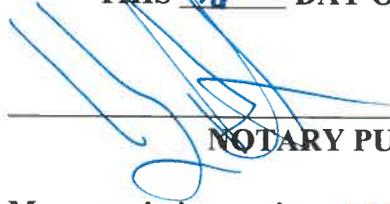
_____
NOTARY PUBLIC

My commission expires: _Upon death_

Harry M. Barton
Notary Public
Notary ID# 90845
Parish of Orleans, State of Louisiana
My Commission is for Life

Entergy New Orleans, Inc.

NEW ORLEANS POWER STATION REVENUE REQUIREMENT

DERIVATION OF THE RATE BASE
(Dollars in Thousands)

Item	1st Full Year
Rate Base	
A. Plant In Service	232,000
B. Accumulated Depreciation	(7,733)
C. Accumulated Deferred Income Taxes	(26,150)
D. Rate Base	198,117

Entergy New Orleans, Inc.

NEW ORLEANS STATION REVENUE REQUIREMENT

DERIVATION OF THE REVENUE REQUIREMENT
(Dollars in Thousands)

	First Full Year of Operation
A. Operation and Maintenance Expense	
1. Payroll	1,591
2. O&M - Fixed, excluding payroll	963
3. O&M - Variable, excluding payroll	654
4. Total Operation and Maintenance Expense	3,209
B. Other Operating Expenses	
1. Insurance	200
2. Property Tax	0
3. Total Other Operating Expense	200
C. Total Operating Expenses	**3,409**
D. Return Of and On Rate Base	
1. Pre-Tax Return	22,932
2. Depreciation and Amortization Expense	7,733
3. Equity AFUDC Gross Up	
4. Total Return Of and On Rate Base	30,664
E. Revenue Requirement	**34,073**

Entergy New Orleans, Inc.

NEW ORLEANS POWER STATION REVENUE REQUIREMENT

DERIVATION OF THE COST OF CAPITAL

ASSUMED 50% COMMON EQUITY

JUNE 30, 2016
(Dollars in Thousands)

Item	Amount	Ratio	Cost Rate	Weighted Cost Rate	
				Post Tax	Pre Tax
A. Long Term Debt	340,116	47.22%	4.96%	2.34%	2.34%
B. Preferred Stock	20,004	2.78%	4.82%	0.13%	0.21%
C. Common Equity	360,119	50.00%	11.10%	5.55%	9.02%
D. Total	**720,239**	**100.00%**		**8.02%**	**11.57%**

NOTE: Items may not foot due to rounding

ENTERGY NEW ORLEANS, INC.

NEW ORLEANS POWER STATION
ESTIMATED FIRST-YEAR REVENUE REQUIREMENT
DERIVATION OF THE ESTIMATED REVENUE REQUIREMENT
(Dollars in Thousands)

	First Full Year of Operation
A. Operation and Maintenance Expense	
1. Payroll	3,631
2. O&M - Fixed, excluding payroll	460
3. O&M - Variable, excluding payroll	2,564
4. Total Operation and Maintenance Expense	6,655
B. Other Operating Expenses	
1. Insurance	0
2. Property Tax	0
3. Total Other Operating Expense	0
C. Total Operating Expenses	**6,655**
D. Return Of and On Rate Base	
1. Pre-Tax Return	20,750
2. Depreciation and Amortization Expense	6,993
3. Equity AFUDC Gross Up	
4. Total Return Of and On Rate Base	27,744
E. Revenue Requirement	**34,399**

ENTERGY NEW ORLEANS, INC.

NEW ORLEANS POWER STATION
ESTIMATED FIRST-YEAR REVENUE REQUIREMENT
DERIVATION OF THE ESTIMATED RATE BASE
(Dollars in Thousands)

Item	1st Full Year
Rate Base	
A. Plant In Service	209,800
B. Accumulated Depreciation	(6,993)
C. Accumulated Deferred Income Taxes	(24,354)
D. Inventory	819
E. Rate Base	179,272

ENTERGY NEW ORLEANS, INC.

NEW ORLEANS POWER STATION
ESTIMATED FIRST-YEAR REVENUE REQUIREMENT
DERIVATION OF THE ESTIMATED COST OF CAPITAL

ASSUMED 50% COMMON EQUITY RATIO

PROJECTED JUNE 30, 2016
(Dollars in Thousands)

Item	Amount	Ratio		Weighted Cost Rate Post Tax	Pre Tax
A. Long Term Debt	340,116	47.22%	4.96%	2.34%	2.34%
B. Preferred Stock	20,004	2.78%	4.82%	0.13%	0.21%
C. Common Equity	360,119	50.00%	11.10%	5.55%	9.02%
D. Total	**720,239**	**100.00%**		**8.02%**	**11.57%**

NOTE: Items may not foot due to rounding

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

ROBERT A. BREEDLOVE

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JULY 2017

TABLE OF CONTENTS

LIST OF EXHIBITS

Exhibit RAB-2   Estimate of O&M Costs for Alternative Peaker

1   **I.   INTRODUCTION AND SUPPLEMENTAL TESTIMONY**

2   Q1.   PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

3   A.   My name is Robert A. Breedlove. My business address is 10055 Grogan's Mill

4   Road, The Woodlands, Texas 77380.

5

6   Q2.   ARE YOU THE SAME ROBERT A. BREEDLOVE THAT FILED DIRECT

7   TESTIMONY IN THIS PROCEEDING?

8   A.   Yes.

9

10 Q3.   WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

11 A.   My Supplemental and Amending Direct Testimony ("Supplemental Direct

12   Testimony") supports the Supplemental and Amending Application ("Supplemental

13   Application") in this proceeding, which seeks, among other things, approval to

14   construct the New Orleans Power Station ("NOPS"), which will consist of either a

15   combustion turbine ("CT") resource with a summer capacity of 226 megawatts

16   ("MW"), or alternatively, seven Wärtsilä 18V50SG Reciprocating Internal

17   Combustion Engine ("RICE") Generator sets ("Alternative Peaker"). My testimony

18   provides the estimated operation and maintenance ("O&M") costs for the Project.

19

1   Q4.   HAS THE COMPANY PREPARED AN ESTIMATE OF O&M COSTS THAT

2   WILL BE INCURRED IN OPERATING THE ALTERNATIVE PEAKER?

3   A.   Yes. Entergy New Orleans, Inc. ("ENO") has prepared an estimate, and has provided

4   that to Company witness Orlando Todd for use in estimating the first-year non-fuel

5   revenue requirement associated with the Alternative Peaker, based on the current best

6   understanding of what equipment will be installed at the site, and based on a number

7   of other assumptions related to operating systems and conditions at the unit beginning

8   in 2019. That estimate is attached hereto as Exhibit RAB – 2.

9

10   Q5.   HOW WAS THE ESTIMATE DEVELOPED?

11   A.   The cost estimates were developed using cost data provided by Wärtsilä, the

12   equipment manufacturer for the RICE technology being considered as the Alternative

13   Peaker. Additionally, other industry sources were consulted, including data by the

14   Electric Power Research Institute and visits to in-service plants that use similar

15   Wärtsilä engine technology.

16

17   Q6.   DOES THE COMPANY EXPECT TO ENTER INTO A LONG-TERM SERVICE

18   AGREEMENT FOR THE ALTERNATIVE PEAKER?

19   A.   At this time, it has not been determined whether the Company will enter into a LTSA

20   for the Alternative Peaker. The Company would not, however, incur any costs under a

21   potential LTSA until the Alternative Peaker enters commercial operation, which (if

22   approved by the Council) is expected in October 2019.

1   Q7.   HAVE ANY OF THE ESTIMATES INCLUDED IN YOUR DIRECT TESTIMONY

2   RELATED TO THE ORIGINALLY PROPOSED CT CHANGED?

3   A.   No.

4

5   Q8.   DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

6   A.   Yes.

AFFIDAVIT

STATE OF TEXAS

COUNTY OF MONTGOMERY

NOW BEFORE ME, the undersigned authority, personally came and appeared, **ROBERT A. BREEDLOVE**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

_____
Robert A. Breedlove

SWORN TO AND SUBSCRIBED BEFORE ME THIS 3RD DAY OF JULY, 2017

_____
NOTARY PUBLIC
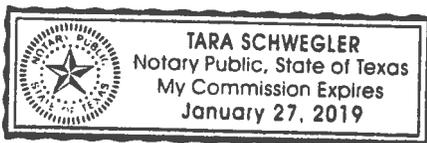
My commission expires: January 27, 2019

TARA SCHWEGLER
Notary Public, State of Texas
My Commission Expires
January 27, 2019

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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

EXHIBIT RAB-2

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JULY 2017