BEFORE THE COUNCIL OF THE CITY OF NEW ORLEANS

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	**)**	

Direct Testimony
of
Patrick W. Luckow
of
Synapse Energy Economics, Inc.

On Behalf of
Sierra Club, Deep South Center for Environmental Justice,
and the Alliance for Affordable Energy

JANUARY 6, 2016

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Patrick Luckow. I am a Senior Associate at Synapse Energy Economics ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power. Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q What is your role at Synapse?

A I focus on calibrating, running, and modifying industry-standard economic models to evaluate long-term energy plans, and the environmental and economic impacts of policy/regulatory initiatives. As part of my work there, I provide testimony on behalf of state consumer advocates and other clients in electricity planning dockets, including California, Hawaii, Arizona, and New Mexico. I also review and evaluate the energy planning practices of utilities in dockets involving long-term planning and rate cases.

Q Please describe your work experience and educational background.

A At Synapse, I have provided consulting services for a wide variety of public sector and public interest clients, including the U.S. Environmental Protection Agency (EPA), the Michigan Public Service Commission, the California Office of Ratepayer Advocates, the Hawaii Department of Consumer Advocate, Consumer's Union, the National Association of State Utility Consumer Advocates, the Regulatory Assistance Project, the Union of Concerned Scientists, Sierra Club, and other organizations.

Prior to joining Synapse, I worked as a scientist at the Joint Global Change Research Institute, a division of Pacific Northwest National Laboratory ("PNNL"). In this position, I evaluated the long-term implications of potential energy policies, both internationally and in the United States, across a range of energy and electricity models. Since 2012, I have been at Synapse, where I run a range of electricity dispatch and capacity expansion models.

I hold a Bachelor of Science degree in Mechanical Engineering from Northwestern University and a Master of Science degree in Mechanical Engineering from the University of Maryland. My full resume is attached as PWL-1.

Q Please describe the purpose of your testimony.

A My testimony focuses on the Application of Entergy New Orleans ("ENO" or "Company") to construct the New Orleans Power Station ("NOPS"). I focus my review on the testimonies of Seth E. Cureington and Charles W. Long. I conclude that the decision to construct NOPS imposes significant financial risks on the Company and its customers, and can safely be deferred for several years.

My testimony assesses both the economic and reliability arguments for the proposed facility, including the initial justification for the project in the 2015 Integrated Resource Plan ("IRP"). As part of my assessment, I review the MISO capacity market forecasts, ENO's plans for NOPS, and propose alternative means of meeting New Orleans' power needs.

Q Please briefly describe ENO's proposed use of the NOPS facility.

A The proposed facility is a 226 MW (summer capacity) gas-fired combustion turbine at the site of the former Michoud plant, which was retired in the summer of 2016. This facility would operate as a peaker—for a limited number of hours each year when electric power demands are at their highest.

The Company describes that the ENO service territory operates within a "load pocket," or a region in which transmission constraints limit the available capacity that can be imported into the territory.[1] This load pocket, called "Downstream of Gypsy," or "DSG" encompasses the region south of Lake Pontchartrain out to the Gulf of Mexico. According to the Company, the NOPS facility would provide needed capacity within the New Orleans city limits, and additional capacity in the DSG load pocket. At the moment, Entergy's Nine Mile facility is the only active facility within the DSG region.

Q Please summarize your findings with respect to the Company's assessment for the need for the NOPS facility.

A The basis for spending $216 million to build NOPS is at best very tenuous. And in fact, building the plant will expose Entergy's customers to additional risks. The need for new local generation was better justified in the preliminary results of the 2015 IRP, when a new CT was first proposed. Since then, several factors have changed:

- The Company has acquired the 495 MW Union Power Station Power Block 1 NGCC, which substantially reduced the potential capacity shortfall that NOPS is supposed to address.
- Updated load forecasts have further reduced the projected shortfall.
- The Company has been ordered by the Council to further assess the potential for incremental energy efficiency.

As a result, NOPS will leave the Company with significantly more capacity than it needs to fulfill its load obligations. In order to justify the economics of that excess capacity, the Company assumes it will sell that excess power for a hefty price in the future. Indeed, the Company assumes a price that is much higher than historical prices, and does not take into account the likelihood that capacity prices will probably grow much more slowly, if at all. As I describe below, a lower forecast—even one that assumes prices rise substantially higher in the future than they are today—would render NOPS uneconomic

[1] Direct Testimony of Mr. Charles Long, page 3 at 11 to page 4 at 2.

and force ENO customers to bear significant, unnecessary costs, well beyond the first year 5.4% rate impact estimated by the company.[2]

In addition, committing ENO customers to paying for this plant well before it is needed will prevent them taking advantage of new technologies or market conditions that could lower their utility bills. The technology and construction techniques proposed are well understood, and it is feasible to monitor market conditions before committing to such a large capital expenditure.

Finally, the reliability need for NOPS is overstated. Transmission alternatives exist that would be as or more reliable with regards to storm outages, and there remains substantial capacity in the load pocket in which the Company operates.

Q What are your recommendations to the City Council?

A First, I recommend that the Council reject the request for authorization to proceed with construction of NOPS. Second, because this capacity is not needed today but may be in the future, I recommend that the Council direct ENO to perform a more rigorous analysis, including additional potential resource alternatives.

Q Please describe the structure of your testimony.

A My testimony first summarizes the analysis done in support of NOPS, including the assumed operational characteristics and reliability impacts. My analysis focuses on the Company's Supplemental Scenario Analysis provided on November 18, 2016 in response to the Council's Advisors request for four additional Aurora modeling runs. I examine several of the assumptions in this analysis and critique the basis behind them.

I then discuss the capacity market assumptions made by ENO, as well as transmission considerations associated with the New Orleans position in a local load pocket. I conclude with my assessment of alternative resources.

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[2] SIE 1-16

2. <u>ENO's Decision to Construct NOPS Relies on an Outdated and Insufficient Assessment</u>

Q How did the Company arrive at the decision to build the NOPS facility?

A The Company conducted an IRP in 2015, in which it evaluated several different resource alternatives to meet its long-term capacity needs ("IRP Analysis"). The IRP Analysis found that new capacity was needed to meet long-term peaking and reserve capacity requirements.

In March 2016, the Company completed an analysis comparing four gas peaking facility alternatives, which resulted in the specifications for NOPS ("NOPS Alternative Analysis").

Q Were any changes made late in the IRP process?

A Yes. In Resolution R-15-542 the City Council approved the ENO purchase of the 495 MW Union Power Block 1, a large gas-fired power plant built in 2003, at a price of $237 million.

The Company conducted a supplemental analysis amending the 2015 IRP to include the Union Power Block 1 purchase ("IRP Supplement").[3] The acquisition of the Union Power Block significantly affected the long-term resource build-out and needs anticipated in the 2015 IRP and substantially changed ENO's need for future generation capacity (See Exhibit PWL-2). Therefore, although the 2015 IRP is cited by the Company as the basis of its assessment for a need for a capacity resource, the core analysis of the 2015 IRP was outdated even before it was finalized.

Q How does the analysis conducted for the 2015 IRP differ from that conducted in support of this Application?

A In the IRP Analysis and IRP Supplement, the Company used Aurora in Capacity Expansion mode, allowing the model to pick the optimal set of new resources based on

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[3] ENO 2015 IRP Final Report. Table 28. Available at: http://www.entergy-neworleans.com/content/IRP/2015_IRP_Final_Report.pdf. Included as Exhibit PWL-2.

costs. In the analysis in support of this Application ("Application Analysis"), the Company appears to have limited its analysis to a production cost analysis in Years 2016-2020, 2025, 2030, and 2035.

Q **What was the City Council's directive to the Company with respect to modeling in this application?**

A On November 3, 2016, City Council directed the Company to file a supplemental analysis consistent with a request from Council Advisors to "perform additional IRP modeling, using its Aurora resource planning software, which would include multiple, updated expansion plans and scenarios in order to assist the Council in determining whether the construction of NOPS is necessary and in the public interest."[4]

In response, the Company produced supplemental testimony on November 18, 2016 ("Supplemental Analysis"). This supplemental testimony relied upon Aurora, the model used by ENO in the IRP, but produced only a different type of analysis, called a "production cost" analysis, rather than capacity expansion analysis, as used in the IRP.

Q **What is the difference between "capacity expansion" and "production cost" analysis?**

A Capacity expansion modeling, used by the Company in the IRP, is an analysis framework meant to assess the best portfolio of resources that will meet long-term system requirements at least cost. The modeling mechanism assesses a range of resource options, typically including both fossil and renewable options. The model handles ranges of fuel price projections and seeks to find the least-cost arrangement of resources (or retirement of existing resources) that meets customer demands. Capacity expansion models handle both variable costs (such as fuel and ongoing maintenance) and fixed costs (e.g., capital). This is a standard mechanism in long-term resource planning used to assess the value of different generation resources.

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[4] See Council Resolution R-16-506, pp. 8–9.

In contrast, production cost modeling, used by the Company in this Application, focuses on the hour-to-hour chronological operations of the system. This type of modeling is used to assess how resources dispatch and operate. Production cost models are relevant in assessing reliability, but require careful use in long-term resource planning. Production cost models do not make specific resource choices, they operate on an *a priori* assumption of fleet composition. They only assess the variable cost of production.

In this case, the Company's valuation of the NOPS facility is based on a limited set of production cost model runs and a separate financial model to handle fixed and capital costs. The Company has done no optimization for the lowest cost resource in this Application.

Q **Did the Company conduct capacity expansion modeling for the supplemental analysis as requested by Council Advisors and required by City Council?**

A No. In response to discovery, ENO confirmed that the Aurora analysis conducted for the Supplemental Testimony was limited to the production cost capabilities of the model. The Company further claimed that "resource additions and other underlying assumptions were specified by the Council's Advisors, as noted in Council Resolution No. R-16-506 (November 3, 2016), so the use of Aurora's capacity expansion was not needed."[5]

Q **Do you agree that the Council Advisors' request precluded the use of a capacity expansion model as used in the IRP?**

A No. For one, the Council, in Resolution 16-506, directly referenced the Advisors' request for ENO to conduct "additional IRP modeling" and include "multiple, updated expansion plans and scenarios" in the Supplemental Analysis.[6] As for the specific instructions that the Council Advisors gave to ENO for the Supplemental Analysis's four model runs, I only have access to the matrix set out in Exhibit SEC-8 from Mr. Cureington. However, I assume that the Company has faithfully reproduced Council Advisors' requests. With respect to build assumptions, Council Advisors only specified that cases either include or

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[5] ENO Discovery Response to SIE 2-6, dated Dec. 30, 2016.

[6] Council Resolution R-16-506, page 8.

exclude NOPS and/or "necessary transmission solutions [to] ensure compliance with NERC [North American Electric Reliability Corporation] Standard TPL-001-4."[7] Nothing in that request precludes ENO from running a capacity expansion model to seek the most cost-effective portfolio of energy and capacity resources—including demand measures.

The substantial departure from the IRP structure to the structure of the Supplemental Analysis—moving from a capacity expansion model to a production cost model—fails to meet both requirements, embodied in Resolution 15-506, that ENO perform additional "IRP modeling" and assess multiple "expansion plans." It is therefore insufficient.

Q Why should the City Council assess the Supplemental Analysis rather than the Application Analysis in this case?

A As described by the Company in response to discovery, the primary value proposition for NOPS is its ability to avoid leaving "customers exposed to volatility in the capacity clearing process in the MISO capacity auction,"[8] and is ostensibly the "lowest reasonable cost option to meet the identified capacity need" of the Company.[9] However, the primary Application Analysis does not test this value proposition at all, instead simply reviewing the total supply cost of four different CT combinations.[10] By no reasonable measure is this a test of whether the NOPS proposal is economically viable or attractive to ratepayers.

The Supplemental Analysis, despite its reliance on a production-cost approach, is the only assessment provided by the Company that actually seeks to evaluate the cost effectiveness of pursuing a CT against any other option, and thus is the only assessment that seeks to establish a value for the CT.

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[7] Cureington Supplemental, SEC-8

[8] ENO Discovery Response to SIE 2-8 (a), dated Dec. 30, 2016.

[9] ENO Discovery Response to SIE 2-8 (c), dated Dec. 30, 2016.

[10] Cureington, page 38 at 6-11.

Q How often did NOPS run under the Company's Supplemental Analysis production cost modeling run?

A [redacted] This confirms that effectively the only value proposition of the CT is as a capacity unit. [redacted]

Q Did the Company's 2015 IRP Supplement consider the incremental demand-side management ("DSM") analyzed in the Company's November 18th Supplemental Testimony?

A No. Case 3 of the Company's Supplemental Analysis modeled an increase in Energy Smart Program Savings by 0.2 percent per year until reaching 2 percent of sales, effectively reducing the Company's projected load growth. The Council Utilities Committee reaffirmed the 2 percent load reduction goal in a resolution passed in December 2016.

By contrast, the 2015 IRP Supplement did not account for the 2 percent load reduction goal. Instead, it merely adjusted the load forecast considered in the IRP to account for the transfer of Algiers to ENO's Service Territory, as well as a set of incremental DSM programs that resulted in a load forecast consistent with the load used in the Case 1 of the Supplemental Analysis.

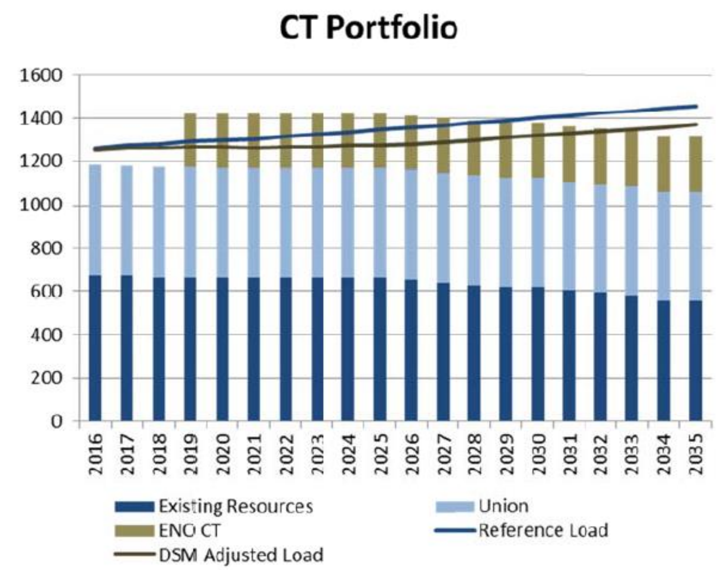
Q What did you determine from your assessment of the ENO IRP Supplement?

A While ENO's initial 2015 IRP assessed a need for new incremental capacity, much of the capacity gap envisioned by ENO was filled with the acquisition of Union, substantially diminishing the case that NOPS is needed.

According to the Company's load and resource balance analysis in the IRP Supplement, while the system without NOPS (but with the Union acquisition) is slightly short (by 91 MW in 2018), the system with NOPS is in surplus by 156 MW, as shown in Figure 1, below.[11] This is a significant change from the original filing with the IRP used to justify the CT. That filing showed a shortage of 433 MW in 2018, reduced to 240 MW in 2019 with the installation of a CT.[12]

Later, I discuss my findings that the ENO system is in even greater surplus with the additional incremental energy efficiency to meet the Council's 2 percent load reduction goal.

Figure 1: Capacity Balance in 2015 IRP Supplement (Reproduced from 2015 IRP Figure 25)



ENO's conclusion that the NOPS CT is the most economic resource to fulfill its capacity needs is unfounded. In the Company's latest analysis in the November 18, 2016 Supplemental Testimony, NOPS results in a significant surplus of capacity. Case 3 of this analysis considered the proposed requirement that the Company implement additional energy efficiency, to meet a 2 percent annual savings target, which would increase the surplus further beyond the Company's preferred scenario, Case 1. The red and blue lines

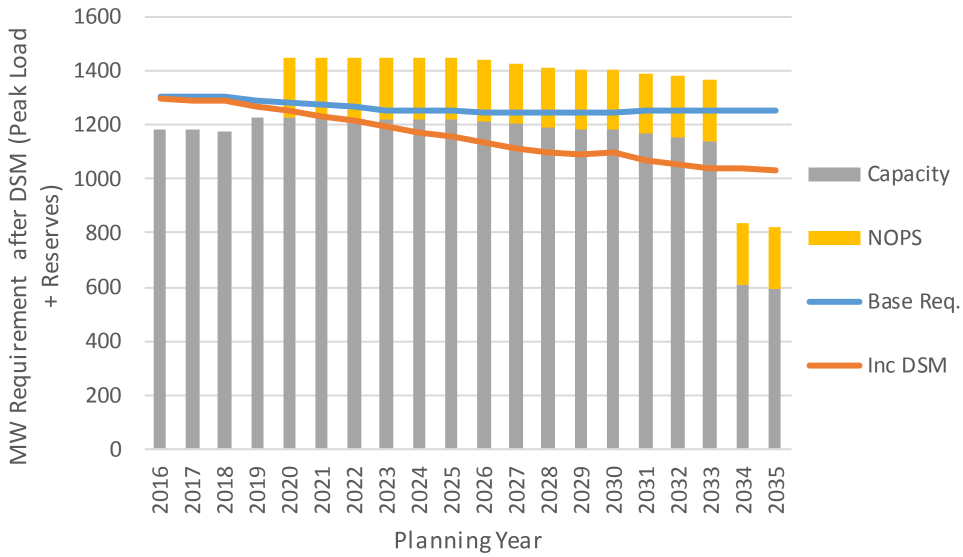
[11] 2015 IRP Supplement 10, Table 12. Feb 2016.

[12] 2015 IRP Supporting Technical Materials, June 2015. Slide 44. Available at: http://www.entergy-neworleans.com/content/irp/Supplement_6-Supporting_Technical_Materials-Public.pdf.

in Figure 2 compare the load requirements in these two cases – a clear surplus is evident through approximately 2030, and the surplus is particularly pronounced when the 2 percent load reduction goal is included.

ENO relies heavily on sales of this excess capacity in the MISO market to justify the economics of NOPS. In essence, ENO is betting ratepayers' money that other utilities in the region will have a need for NOPS excess capacity, and would be willing to pay top dollar for that capacity—effectively the all-in price of the CT. Only by claiming capacity at this high price point is ENO able to justify a need for NOPS.

Figure 2: ENO Existing and NOPS Capacity in November 18th 2016 Supplemental filing, compared to Forecasted Peak Requirements



As I discuss later, ENO also assesses that the capacity market poses significant risks and uncertainties. Therefore, it is surprising and inconsistent that ENO would seek to rely on this highly uncertain market quickly reaching and remaining at a high price to justify the expense of the NOPS facility, while at the same time dismissing the risk that the market prices could be much lower.

3. <u>REVIEW OF ENO SUPPLEMENTAL ANALYSIS</u>

Q Why does your review focus on the Supplemental Analysis?

A I focus on the Supplemental Analysis for two reasons. First, as I stated earlier, the Supplemental Analysis is the only assessment provided by the Company that attempts to determine a value for NOPS over any other alternative. Secondly, the state of the market has changed substantially since the IRP was filed. While the IRP provides reasonable assumptions for long-term planning, the MISO capacity market is undergoing considerable structural changes and ENO has since agreed to purchase other resources. While I also agree with ENO that a detailed production cost analysis is relevant to this decision, the production-cost modeling has the flaws for resource planning purposes I described earlier. The analysis in the Application focused on four quite similar alternatives, and the cases with and without NOPS in the Supplemental analysis provide a basis for comparison of two scenarios with and without NOPS, on an operational basis.

Q Do you agree with ENO that Case 2 of the Supplemental Analysis—the only case without NOPS—is an unrealistic scenario?

A No. ENO argues that Case 2, in which NOPS would not be built and ENO instead invests in transmission upgrades and market purchases of capacity, exposes customers to MISO capacity market risks and does not meet local reliability arguments. Later in this testimony, I will discuss how ENO's capacity price assumptions represent an unrealistic upper bound on capacity prices, but realized prices could be significantly lower. I also address the local reliability concerns.

Q Where were the results of the Supplemental Analysis?

A The updated analysis stated that Case 1, the Company's preferred portfolio with NOPS, was the most cost-effective. This scenario was $35 million less expensive than Case 2, the only scenario without NOPS. Case 2 included the cost of additional transmission reinforcements to make the system NERC-compliant. Considering a $216 million investment in NOPS, $35 million is a relatively small difference in plans.

Q Based on SEC-9, how do capacity purchases and sales with the MISO market drive the conclusions from the Summary analysis?

A [redacted]

4. <u>THE NOPS ANALYSIS OVERSTATES MISO CAPACITY MARKET PRICES</u>

Q Is the support for the NOPS CT reliant on assumptions related to the MISO capacity market?

A Yes. As I discussed earlier, the primary economic value proposition for NOPS is its ability to contribute capacity to ENO, and sell excess capacity to other utilities. In contrast, the scenario in which NOPS is not built and transmission is instead buffered suffers, in ENO's analysis framework, from a small capacity shortfall that requires the purchase of excess capacity.

A [redacted]

ENO claims that "moving forward with deployment of NOPS now will mitigate customers' exposure to higher capacity prices as equilibrium approaches as well as the potential cost premium and longer lead times that may be required for new CT resources as equilibrium occurs."[13] However, this argument hinges on the Company's unreasonable

[13] Cureington, page 32 at 19-22.

assumption that capacity prices will remain high, and thus, makes building its own capacity—and selling some of it—appear more attractive.

Q What is the MISO capacity market?

A MISO's capacity market, or "Planning Resource Auction" ("PRA") is an element of the MISO Resource Adequacy framework. That framework has been changing over the course of the last few years, with a substantial change just this year. MISO, as the Regional Transmission Organization ("RTO") and ISO for 15 U.S. states and part of Canada, is charged with ensuring that reliability requirements are met across the region. In keeping with this mission, MISO operates a capacity market such that utilities with excess capacity can sell those reserves to utilities that require capacity.

Up to 2013, MISO had required that individual load serving entities ("LSEs") hold sufficient capacity for their own requirements, allowed bilateral trades, and facilitated a voluntary capacity market for excess capacity not sold through bilateral sales. Traditionally, there has been little volume in the voluntary capacity market, and LSEs have been reluctant to depend on this resource. In 2013, MISO opted to shift to a more comprehensive capacity market with a multi-region auction. Under this framework, LSEs could either provide their own resource requirements (called a Fixed Resource Adequacy Plan, or "FRAP"), or participate in the capacity market by buying and selling capacity. In April 2016 the first MISO-wide capacity market auction closed with 141.5 GW offered into the market (including FRAP) to cover 135.5 GW of load requirement.[14]

Q What assumptions does ENO make about the MISO capacity market?

A The Company assumes that retirements in the next several years push the capacity market to "equilibrium". As a result, ENO forecasts capacity prices at the cost of a new combustion turbine—in capacity markets, this is referred to as Cost of New Entry, or "CONE." The MISO capacity market has recently been in a state of surplus, with very low capacity prices.

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[14] https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/AuctionResults/2016-2017%20PRA%20Summary.pdf.

The Company's assessment relies on two important assumptions: (1) that the capacity market in MISO will tighten sufficiently by 2022 to drive up capacity prices and (2) that these extremely high capacity prices will be sustained through the end of the analysis period in 2035. Both of these assumptions are problematic.

Q Is the Company's assumption that the MISO capacity market will drive towards equilibrium in 2022 reasonable?

A No. This is a theoretical concept that has not been borne out in reality. In December 2016, NERC released the 2016 Long Term Reliability Assessment ("LTRA"),[15] an assessment of resource adequacy and transmission needs across reliability authorities in North America. For the Resource Adequacy section of the report, NERC assesses all known capacity within a region, known and/or anticipated retirements, and both known impending resources as well as announced but not permitted resources. The report seeks to assess when reliability issues may arise due to impending shortfalls. NERC's report on MISO indicates that accounting only for highly certain new resources,[16] MISO's margin will fall to its planning reserve margin (i.e. assumed excess capacity needed to maintain sufficient reliability) in 2022. However, taking into account resources that are in the region's interconnection queue but have not received approval yet,[17] MISO remains above its planning reserve margin through 2026—the end of NERC's planning period.

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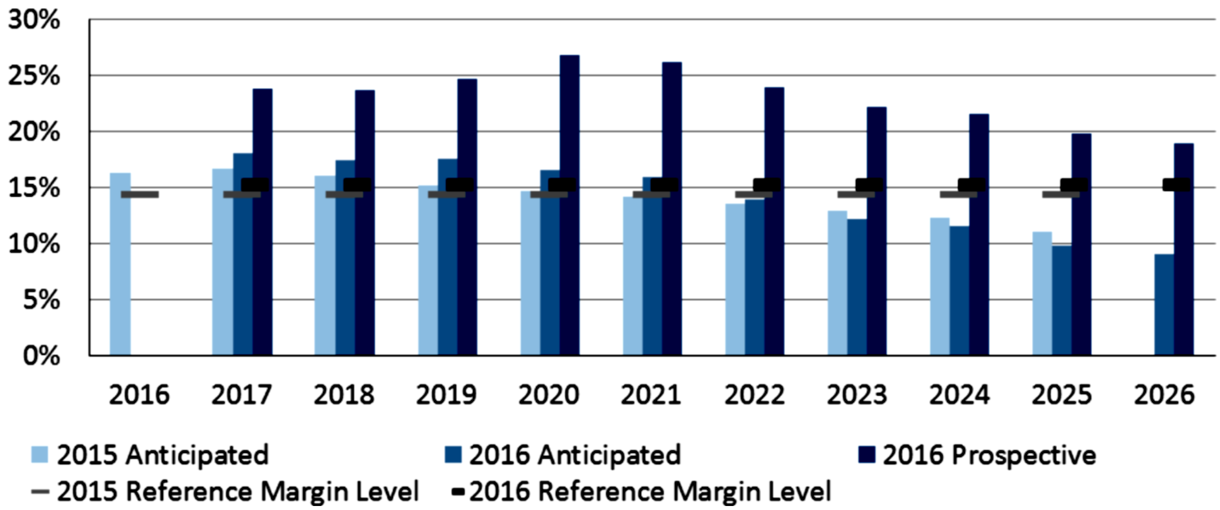
[15] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf.

[16] NERC calls highly certain new resources "anticipated." These are defined as "capacity that has completed construction, is under construction, has a signed or approved ISA/PPA/CSA/WMPA, is included in an integrated resource plan, or is under a regulatory environment that mandates a resource adequacy requirement."

[17] NERC calls resources that have not received approval "prospective" resources.

Figure 3. NERC 2016 Long Term Reliability Assessment for MISO. Figure 1.7



NERC's 2016 "anticipated" resources set a lower boundary on the likely resources in the MISO footprint, while the "prospective" resources set an upper boundary. While it is unlikely that all—or even most—of the prospective resources listed by MISO will be built, it is also unlikely that *only* the resources currently listed as "anticipated" will be constructed. It is notable that NERC assesses seven gigawatts of new potential capacity for MISO by 2018, more than any other RTO. Clearly, a number of utilities across MISO are moving quickly to replace retiring coal capacity. ENO's assessment that the capacity market will tighten so substantially that prices will ramp up to CONE is overly optimistic, and risky. Should these extremely high capacity prices not materialize, then ratepayers could have been better served without NOPS.

Q Is gross CONE a reasonable proxy for long-term capacity prices?

A No. Assuming capacity prices trend *towards* the cost of new entry does seem logical in theory—and this is why such markets use CONE as a basis for setting price rules. Importantly, other capacity markets use what is referred to as "net CONE," which reduces the costs of entry by the revenues new resources would be expected to receive in other markets (i.e. energy). The Company, in contrast, appears to have used an estimate of "gross CONE," or the full cost of a CT without any other revenue stream. It does not appear that the Company included potential energy market revenues in its calculation of projected capacity market prices.[19] An efficient capacity market participant could, at most, bid net CONE. This would make the purchaser whole on the capacity and energy markets. Bidding gross CONE would inflate the required revenue needed to participate in the markets and would thus be underbid by other market participants. A recent analysis conducted for MISO, using the same gross CONE as the Company does in this case — found net CONE to be 25 percent less than the Company's forecast using gross CONE. Therefore, even the maximum price modeled by ENO is an overestimate.[20]

In practice, MISO prices tend to be far below even net CONE. Exhibit PWL-2 below charts both historical prices in MISO and PJM, another major RTO. Unlike MISO's current structure, PJM is a full capacity market whereby nearly all capacity is bid in. This figure shows the capacity price spike mentioned in Seth E. Cureington's Direct Testimony (p. 33), when MISO Zones 2 through 7 jumped from $3.58/MW-day to $72/MW-day. Cureington cites this price spike as an example of the risk ENO anticipates in relying on MISO capacity market purchases. But as Figure 4 shows, ENO's long-term price forecast relies on rapid increases far in excess of the price spike Cureington cites. In contrast to ENO's assumption, both PJM and MISO prices have tended to be far below gross or net CONE. Meanwhile, both regions currently carry excess capacity.

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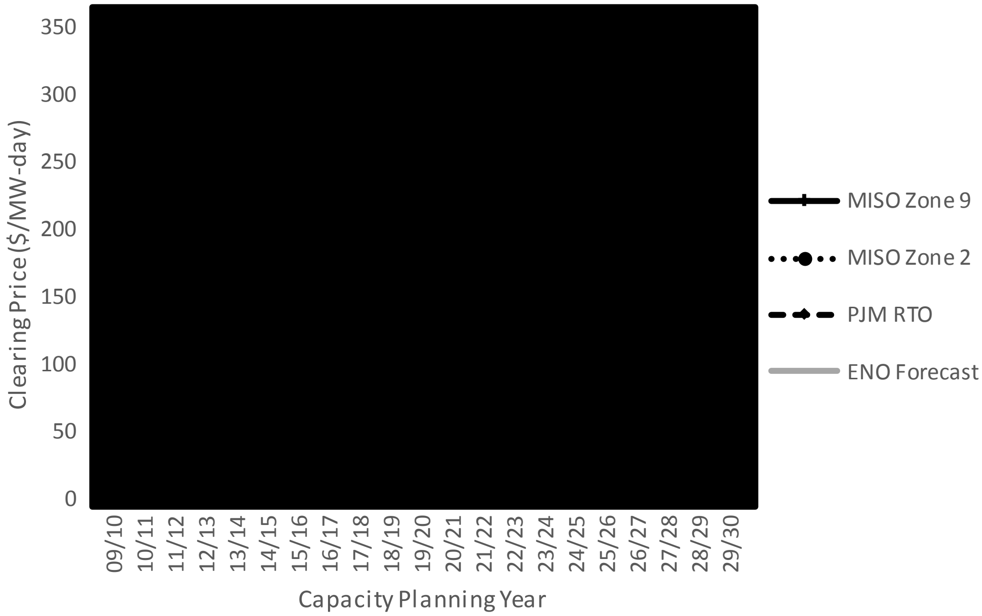
[19] Response to Sierra Club Discovery request 1-11 (HSPM), Dec, 2016.

[20] The Brattle Group. "MISO Competitive Retail Solution: Analysis of Reliability Implications". September 2016. Slide 12. https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/Markets%20Committee/2016/20161011/20161011%20Markets%20Committee%20of%20the%20BOD%20Item%2001c%2020160919%20RASC%20CRS%20Analysis%20of%20Reliability%20Implications.pdf

Figure 4: Historical MISO and PJM capacity prices, compared to the ENO forecast (HSPM)



Q How would the Company's economic analysis change if it had assumed a capacity cost in the middle of the range of recent estimates?

A Assuming a more reasonable cost of $150/MW-day, I find the case with NOPS to be $32 million *more* expensive than the transmission upgrade only, i.e., no-NOPS alternative. I arrived at this estimate by replacing the capacity market forecast in the Company's workpapers with a forecast reflective of a year-one capacity cost of $150/MW-day, as opposed to the Company's estimate of $247/MW-day. This revised value is much higher than MISO prices have historically been, but within the range of recent prices in PJM. These results are summarized in Table 1. As already described, Case 1 represents ENO's modeling of the NOPS, while Case 2 reflects no NOPS and transmission upgrades necessary to meet NERC requirements.

Table 1: Total Supply Cost Comparison ($2016MM, PV)

		Case 1	**Case 2**	**Savings due to NOPS**
Nov. 18th Filing	[$MM]	$2,076	$2,111	$35
Mid-Range Capacity Market Forecast	[$MM]	$2,113	$2,082	-$32

Q Is it reliable to rely on capacity purchases for a significant share of a utility's needs?

A Yes. In Case 2 of the supplemental testimony, the ENO system is short between 45MW and 60MW in 2020 through 2022 (3% to 5% of the total load requirement). This is a significant reduction from where the system will be in 2017 – 121MW short. It is common practice for utilities to balance short term resource needs with capacity at this scale. Entergy Louisiana, in its 2015 IRP, relied upon 1,762MW of market purchases to meet its 2018 resource need (14% of the total load requirement).[20] New units reduce this demand after 2020, but ELL continues to rely on smaller levels of purchases throughout the IRP study period – never selling excess capacity.

Q Do other proposed or under-construction power plants reduce the likelihood of high capacity prices?

A Yes. Substantial new natural gas capacity is being built across the MISO region. Local to the Company's service territory, the Louisiana Public Service Commission has already approved Entergy Louisiana's St. Charles Power Station at the site of the existing Little Gypsy Power station in St. Charles Parish.[21] This 980 MW combined cycle gas plant is slated for completion in 2019. Entergy Louisiana has also proposed the Lake Charles Power Station, a 994 MW combined cycle plant in Westlake, Louisiana, with an anticipated in-service date of summer 2020. Both of these plants would contribute nearly 2 GW of additional capacity to the same MISO zone where New Orleans resides.

5. THE LOCAL LOAD POCKET

Q ENO makes two arguments on the need for NOPS—an economic argument and a reliability argument. You have discussed the uncertainties in the economic case, but

[20] Entergy Louisiana 2015 IRP, Table 19, page 41. Available at: http://www.entergy-louisiana.com/content/irp/2015_0803_Louisiana_Final_IRP_Public.pdf

[21] LPSC Order No. U-33770, *Entergy Louisiana et al., In re: Joint Application for Approval to Construct St. Charles Power Station, and for Cost Recovery* (Dec. 14, 2016).

is local peaking capacity in New Orleans required for system reliability, independent of economics?

A No. The defined DSG load pocket is supported by existing local generation, and numerous transmission interconnections from outside the load pocket.[22] Reliability standards require sufficient resources under different contingency criteria, such as the loss of different combinations of transmission and generation elements. However, the presence of multiple transmission interconnections into the DSG area, along with multiple units at the Nine Mile power station renders the full 226 MW NOPS superfluous under conditions of transmission and generation loss that meet NERC standards for reliability testing. I demonstrate this below.

Q Is there justification for any portion of the claimed 226 MW need for the DSG load pocket?

A No, not if transmission improvements are undertaken.

Q What are the specific reliability requirements associated with the presence of the DSG load pocket?

A There are two categories of reliability requirements: (1) resource adequacy, and (2) transmission security needs.[23]

Q Please describe the resource adequacy aspect of the reliability requirement.

A Resource adequacy refers to a sufficiency of power resources to meet the peak load needs of the DSG load pocket, accounting for the situations where transmission capability into the region is diminished due to contingency events such as the loss of one or more transmission lines. Resource adequacy requirements also account for situations where some DSG load pocket generation is unavailable due to forced outages. Combinations of

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[22] See response to discovery, SIE 2-9 b. and ENO transmission maps, indicating nine points of transmission support into the DSG load pocket, and 2,440 MW of internal generation, primary from the 3 units at the Nine Mile station.

[23] NERC standards include transmission security standards referred to generally as the TPL reliability standard. There is no applicable NERC standard for resource adequacy, but there are industry standards that apply, for example the need for Entergy to maintain a 12% planning reserve margin over peak load.

transmission loss and generation unit loss are also considered when assessing resource adequacy needs.

Q Is there a NERC standard for resource adequacy that applies in this situation?

A No. ENO confirms this in response to SIE 2-9 k. As long as the transmission improvements are made, resource adequacy needs can be met by resources located within and outside of the load pocket, without construction of NOPS.

Q Please describe the transmission security aspects of reliability requirements.

A Transmission security refers to the ability of the transmission system to provide reliable supply under different contingency situations. It includes situations that may be more stringent than the transmission contingency events that are considered when assessing resource adequacy. For example, transmission security analysis may require that sufficient voltage exists at all points of the DSG load pocket in a situation where multiple transmission lines are out of service, even though there may be more than sufficient resources available to meet the load in the DSG region.

Q Has ENO demonstrated that the NOPS plant is required to ensure transmission security in the DSG load pocket?

A No. ENO suggests that resource adequacy needs require NOPS, but they do not make a claim that the transmission security per se will be at risk if NOPS is not built, as long as transmission improvements are made.

Q Is transmission security absent the NOPS plant dependent on additional transmission system reinforcement in the DSG load pocket area?

A Yes. The responses to discovery[24] indicate that absent transmission reinforcement of existing circuits, there would be violations of transmission security—thermal or voltage deficiencies on the transmission grid.

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[24] See ENO Response to Discovery, Advisors 1-19 d (designated CEII confidential).

Q Are transmission lines inherently less reliable than centralized generation facilities?

A No, in fact they generally exhibit lower levels of forced outage than many generation facilities. Their contribution to reliability is considerable, as they provide access to a larger set of resources that can be used to at least partially meet resource adequacy criteria even within a load pocket.

Q ENO outlines eight transmission projects in Case 2 of the Supplemental Analysis. Might these be a good idea independent of NOPS?

A Yes. These projects upgrade the existing transmission assets within the load pocket, essentially improving the "weak links" that already exist. The nominal cost of these improvements, [redacted], is considerably less than the capital costs for NOPS.[25]

Q Are there other transmission projects that will influence the need for NOPS?

A Yes. Specifically, the Southeast LA Economic Project (DSG Alternative 6), which is approved as part of the MISO 2016 MTEP,[26] will provide for 650 MW of additional import capability into the DSG load pocket, and would be in service by 2022. This transmission improvement is incremental to the resources considered in Case 2 of ENO's supplemental analysis. It would afford the ENO service area access to additional resources in the MISO South region.

Q In the event of a disruption, would ENO have black start capabilities with NOPS, or can black start capability be provided by other units in the region?

A Black start capability refers to the ability of a generating resource to re-start on its own in the event of a loss of power to the surrounding grid. In discovery, the Company noted that NOPS would not have black start capability.[27] Other units in the region, both inside and outside the load pocket can provide black start capability. NOPS is not required in

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[25] Response to Advisors 1-19 d., indicating five 115 kV and three 230 kV reinforcement projects on existing transmission lines.

[26] MISO letter to FERC, Midcontinent Independent System Operator, Inc.'s Informational Filing Reporting on MISO's progress in achieving comparability between the First Planning Area and the Second Planning Area, Docket No. ER12-480-000

[27] Advisors 1-15(a)

order to provide necessary black start capability into the region because the transmission connections into the DSG load pocket are both numerous (nine separate lines) and of ample capacity (in total, a capability of [redacted]). The recently completed Ninemile 6, which is within DSG, can burn fuel oil in addition to natural gas, providing added stability in the event that a hurricane disrupts natural gas supplies. A large part of the justification for Ninemile 6 was that locating a large, flexible generator close to load (just across the river from New Orleans) would facilitate system restoration following a hurricane.[28]

Q How would reliability into the load pocket be affected if there were multiple transmission line outages?

A Even with multiple transmission line outages, the capacity into the load pocket available from transmission resources still exceeds peak load needs. For example, even if two of the largest transmission lines into the load pocket were unavailable, there would still be more than [redacted] of interconnection capacity into the load pocket.[29]

6. Alternative Resources

Q Can intermittent resources and energy efficiency meet the Company's peaking and reserve needs?

A Yes. Although they are not dispatchable, such resources reliably contribute to reducing peak demand. The majority of utilities and system operators credit some fractional share of intermittent resource capacity towards peak needs. The Company itself, in its IRP planning, gave solar resources a credit for 25 percent of their nameplate capacity, and wind resources a 14.7 percent credit. In the analysis conducted for the Supplemental Testimony, the Company increased the solar resource capacity credit to 50 percent—but

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[28] "Entergy Louisiana to Build State of the Art Generation Unit at Ninemile Point Plant." June 2011. http://www.entergy.com/News_Room/newsrelease.aspx?NR_ID=2178.

[29] Response to SIE 2-9 b., summing up the individual MVA ratings of the nine lines that make up the boundary into the load pocket ([redacted]), and after removing the two largest lines from the list ([redacted]).

did not allow the model to build new capacity. In this Application, the Company assumed that such resources were not worth consideration.

Q How is the value of energy efficiency's contribution to peak demand reflected in the Company's analysis in this Application?

A The Company did not consider energy efficiency as a viable resource to meet the need considered in this case. It did, however, model the peak demand impacts of energy efficiency at the City Council's request in Case 3 of the Supplemental Testimony filed on November 18, 2016. This case considered a ratcheting up of the Energy Smart program to reach annual savings levels of 2 percent. Under this scenario, the Company had a larger capacity surplus in future years, which it assumed to be sold at market rates, as discussed in Section 3 of my testimony. By 2022, with both NOPS and additional energy efficiency, the Company's capacity surplus would reach 227 MW—the size of NOPS.

Q Was storage adequately considered in the Company's analysis?

A No. The Company did include battery storage in a screening analysis done for the 2015 IRP, but used flawed cost assumptions: It assumed capital costs would increase from $2,400 per kW in 2014 to $3,151 per kW in 2025. The reality is that storage has seen rapid cost *declines* over the past several years, and most industry experts expect those declines to continue.

Q Does the ability to defer the need for new capacity increase the viability of storage?

A Yes. The costs of storage are falling rapidly. The recently released Lazard Levelized Cost of Storage report anticipates capital cost reduction of 24 percent for an average lithium system used for capacity purposes. The report projects that other technologies will have even greater cost declines.[30] Some utilities are already procuring storage competitively as compared other flexible or peaking resources – in 2014, Southern California Edison

[30] Lazard Levelized Cost of Storage. December 2016. https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf.

selected a 100MW battery system built by AES as part of its Local Capacity Requirement Request for Offers ("LCR RFO"), in lieu of a gas CT peaker plant.[31]

7. SUMMARY

Q Please summarize your findings on NOPS

A My findings are as follows:

1) The economic argument for NOPS is weak.

The Company's justification for NOPS is based heavily on a capacity market forecast that is extremely high. The market reaching a high equilibrium price is a theory that has not been borne out as historical capacity market prices have not reflected this "eventuality." With a "mid-level" capacity price forecast, NOPS becomes $32 million more expensive than the transmission alternative. Thus this assumption alone turns the investment uneconomic.

The transmission enhancement scenario provides near-term benefits by reducing the extent of the DSG load pocket, at a significantly lower upfront investment to the Company and its ratepayers. This alternative presents less risk because it is not reliant on the sale of surplus capacity to justify the economics.

2) On a reliability basis, there are other alternatives to NOPS.

Transmission reinforcements provided an additional level of supply security to the Company and its customers, through the ability to import generation from regions less affected by storm outages. NOPS would not be designed without black start capability that could assist in bringing power back to the area after an outage. High voltage transmission upgrades can be completed to be resistant to high winds and flooding, and are not susceptible to local fuel supply limitations or to the flooding that has historically been a problem at the Michoud site.

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[31] Utility Dive. "Inside Southern California Edison's energy storage strategy". Sept. 22, 2015. http://www.utilitydive.com/news/inside-southern-california-edisons-energy-storage-strategy/406044/

In aggregate, the existing Ninemile facility within the local load pocket has more generating capacity than the Company's peak load, although the ENO only owns a share. The recently completed Ninemile 6 is highly flexible, both in its ability to turn on quickly, and in its ability to switch fuels.

3) Deferring the need for new investment today will provide ENO with a number of low-cost alternatives in the future.

The additional level of DSM resources currently under consideration by the City Council would bring ENO nearly up to the levels being achieved by leading states, and substantially reduce the Company's peak load requirements in the future. By 2022, the Company would have surplus capacity equal to the capacity of NOPS.

In addition, the cost of intermittent renewable energy continues to fall. Despite the Company's contention, wind and solar resources would indeed reduce the peak load requirements going forward. Avoiding a multi-hundred million dollar decision today would allow the Company to pursue lower cost resources in the future. Making that multi-hundred million dollar investment today could foreclose future, lower-cost alternatives.

The consideration given to storage resources in the 2015 IRP was limited, and assumed an unrealistic cost trajectory. Due to their high level of flexibility and rapid charge and discharge capabilities, battery storage resources are particularly well suited to provide the grid services the Company is looking for in a new CT. Realistic cost trajectories assume cost declines by 26 percent by 2020. If, at that time, capacity prices seem likely to rise to the upper-bound limits the Company assumed, and the Company's DSM efforts have failed to reduce peak load requirements, the Company could likely procure battery storage at a lower overall cost than a CT in time to meet its resource needs.

Future analysis of potential resource alternatives should be done with capacity expansion modeling, to understand the lowest cost resource to meet the Company's needs.

Q Does this conclude your testimony?

A Yes

AFFIDAVIT

STATE OF Massachusetts)
)
COUNTY OF Middlesex)

I, Patrick Luckow, do hereby swear under the penalty of perjury the following:

That I am the person identified in the attached prepared testimony and that such testimony was prepared by me under my direct supervision; that the answers and information set forth therein are true and accurate to the best of my personal knowledge and belief; and that if asked the questions set forth herein, my answers thereto would, under oath, remain the same.

Patrick Luckow

SWORN TO AND SUBSCRIBED BEFORE ME THIS 4 **DAY OF** JAN, 2017

NOTARY PUBLIC

My commission expires: July 27, 2018

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

Patrick Luckow, Senior Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate,* 2015 – present*, Associate*, May 2012 – June 2015.

Provides consulting services, conducts research, and performs analysis of energy investments. Calibrates, runs, and modifies industry-standard economic models to evaluate long-term energy plans, and the environmental and economic impacts of policy/regulatory initiatives.

Joint Global Change Research Institute, College Park, MD. *Scientist*, 2009 – 2011.

Evaluated the long-term implications of potential climate policies, both internationally and in the US, across a range of energy and electricity models. Modeled large-scale biomass use in the global energy system. Led a team studying global wind energy resources and their interaction in the Institute's integrated assessment model. Utilized updated global wind supply curves to help understand both onshore and offshore wind deployment, and issues associated with transmission requirements, intermittency, and technology costs.

DaimlerChrysler, Auburn Hills, MI. Stress Lab & Durability *Development Intern*, 2007.

Completed load and vibration data acquisition and analysis on various Chrysler vehicles, and contributed to the development of an improved generic body vibration profile.

Northrop Grumman, Rolling Meadows, IL. *Defensive Systems Division Co-op*, 2005 – 2007.

Designed new enclosures and mounting structures for electronic components, silenced existing enclosures, and conducted thermal testing of complete systems.

EDUCATION

University of Maryland, College Park, MD
Master of Science in Mechanical Engineering, 2009.

Northwestern University, Evanston, IL
Bachelor of Science in Mechanical Engineering, 2007.

PUBLICATIONS

Fisher, J., P. Luckow, A. Horowitz, T. Comings, A. Allison, E.A. Stanton, S. Jackson, K. Takahashi. 2016. *Michigan Compliance Assessment for the Clean Power Plan: MPSC/MDEQ EPA 111(d) Impact Analysis*.

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Hawaii Public Utilities Commission (Docket No. 2012-0185): Direct testimony and exhibits regarding the proposed Aina Koa Pono Biofuel Project. On behalf of the State of Hawaii Division of Consumer Advocacy. March 2013.

Resume dated October 2016

Entergy New Orleans, Inc.

2015 Integrated

Resource Plan

February 1, 2016

Table 28: ENO Preferred Portfolio Stakeholder Input Case--Load & Capability 2015-2035 (All values in MW)

Load & Capability 2016—2035																				
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Requirements																				
Peak Load	1,125	1,136	1,143	1,153	1,159	1,163	1,175	1,183	1,193	1,201	1,209	1,220	1,230	1,241	1,251	1,261	1,271	1,281	1,291	1,301
Reserve Margin (12%)	135	136	137	138	139	140	141	142	143	144	145	146	148	149	150	151	153	154	155	156
Total Requirements	1,260	1,273	1,280	1,291	1,298	1,303	1,316	1,325	1,336	1,345	1,355	1,366	1,378	1,390	1,401	1,412	1,424	1,435	1,446	1,457
Resources																				
Existing Resources																				
Owned Resources	642	642	642	642	642	642	641	641	641	641	633	621	608	598	598	585	575	562	539	539
PPA Contracts	11	11	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-
LMRs	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Identified Planned Resources																				
Union[43]	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
Other Planned Resources																				46
DSM[44]	7	12	18	25	34	44	52	60	64	69	75	78	81	80	82	83	86	87	88	88
CT	-	-	-	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Market Purchases (Sales)	73	80	91	(156)	(158)	(162)	(156)	(154)	(148)	(144)	(133)	(112)	(90)	(67)	(58)	(33)	(15)	9	42	53
Total Resources	1,260	1,273	1,280	1,291	1,298	1,303	1,316	1,325	1,336	1,345	1,355	1,366	1,378	1,390	1,401	1,412	1,424	1,435	1,446	1,457

[43] Union plant acquisition is completed pending regulatory approvals.
[44] Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).