EARTHJUSTICE

September 18, 2024

VIA HAND DELIVERY
Ms. Terri Bordelon
Louisiana Public Service Commission
Records Division
602 N. Fifth St.
Galvez Bldg, 12th Floor
Baton Rouge, LA 70802

> ***Re:*** **In Re: Request For Certification of the Construction of the Bayou Power Station, Including Cost Recovery.**
> ***Louisiana Public Service Commission Docket No. U-37131***

Dear Ms. Bordelon:

Please find enclosed for filing both the public version and Confidential/HSPM version (filed under seal) of the Direct Testimony of Michael Goggin, with exhibits, in the above-referenced docket.

Thank you for your attention to this matter. Please contact me if you have any questions with regard to this filing.

Very truly yours,

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STATE OF LOUISIANA

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

ENTERGY LOUISIANA, LLC, Ex Parte.	)	
	)	
IN RE:REQUEST FOR CERTIFICATION OF THE CONSTRUCTION OF THE BAYOU POWER STATION, INCLUDING COST RECOVERY	)))))	**DOCKET NO. U-37131**

Direct Testimony and Exhibits of

Michael Goggin

On Behalf of the

Alliance for Affordable Energy

Public Version

September 18, 2024

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Introduction

Q. Mr. Goggin, please state your full name and occupation.

A. My name is Michael Goggin, and I am the Vice President of Grid Strategies, LLC, which is incorporated in Bethesda, Maryland.

Q. Summarize your education and professional experience.

A. I have worked on electric utility regulatory issues for nearly twenty years. At Grid Strategies, LLC, I have served as an expert on utility regulatory topics for a range of clients interested in clean energy over the last six years, including state utility regulators, consumer advocates, grid operators, and non-profit organizations. For the preceding ten years, I was employed by the American Wind Energy Association ("AWEA"), now known as the American Clean Power Association, where I provided technical analysis and advocacy on electricity market and transmission matters. This included directing AWEA's research and analysis team from 2014–2018. Prior to that, I was employed at a firm serving as a consultant to the U.S. Department of Energy and two environmental groups.

Over the course of my career, I have co-authored over one hundred filings to the Federal Energy Regulatory Commission ("FERC"); served as a technical reviewer for over a dozen national laboratory reports, academic articles, and renewable integration studies; and published academic articles and conference presentations on renewable energy, transmission, and policy. I have also served as an elected member of the Standards, Planning, and Operating Committees of the North American Electric Reliability Corporation ("NERC"). I hold an undergraduate degree with honors from Harvard University. My qualifications are further summarized in Exhibit MG-1.

Q. Have you previously testified in utility regulatory proceedings?

A. Yes. I have testified dozens of times before state and federal utility regulators, including in the states of Arizona, Colorado, Georgia, Illinois, Indiana, Iowa, Kentucky, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, as well as before FERC.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Alliance for Affordable Energy ("AAE").

Q. What is the purpose of your testimony?

A. I review the economic analysis in Entergy Louisiana, LLC's ("Entergy") testimony comparing the cost of the proposed Bayou Power Station ("BPS") against the cost of the transmission alternative. More generally, I assess the reasonableness of Entergy's proposal, including:

- what alternatives were evaluated,
- what costs and benefits should be included in the analysis of BPS and alternative cases,
- the methods and inputs used to calculate those costs and benefits, and
- whether the alternatives offer comparable reliability and resilience.

Q. Please summarize your testimony.

A. First, I identify numerous flaws in Entergy's economic analysis that overstate the value of its proposed BPS, as well as the cost of the transmission alternative. I present a revised economic analysis that shows the transmission alternative is far less costly than the BPS.

Second, I demonstrate that a transmission alternative is superior to BPS for electric reliability and resilience. Transmission provides a range of reliability services instantly so the lights can be kept on during a system disturbance. In contrast, customers served by Entergy's proposed BPS microgrid proposal would experience a blackout and then go through a potentially lengthy and risky load restoration process.

Third, I explain why other resources would be far more cost-effective than BPS for meeting Entergy's system-wide energy, capacity, and flexibility needs.

Finally, I present another transmission solution that Entergy failed to evaluate and that would likely also offer a lower cost than BPS.

Q. What are your recommendations to the Commission?

A. Based on the conclusions summarized above and presented below, I respectfully recommend that the Commission reject Entergy's Application for approval to build the BPS. The Commission should also direct Entergy to thoroughly investigate and develop refined cost estimates for transmission alternatives, including:

- The Company's proposed transmission alternative, but without the unnecessary conversion of the Golden Meadow-Barataria and Valentine-Clovelly-Golden Meadow lines to 230 kiloVolt ("kV") operation, for the reasons outlined in Section I.B. of my testimony. If necessary, this assessment could include deployments of small amounts of demand response, battery storage, and/or solar to meet load growth or other local reliability needs.

- The transmission alternative outlined in Section IV of my testimony, which includes rebuilding some or all of the Valentine-Clovelly-Golden Meadow transmission line with two circuits mounted on each transmission structure.

Those alternatives should then be compared against a revised estimate of the cost of the BPS, after correcting the errors identified in Section I.A. of my testimony. Alternatively, if the Commission believes the record is sufficient to determine that the transmission alternative (without the unnecessary 230 kV conversion) is superior to the proposed BPS, it could direct Entergy to file a certificate for the Commission to approve building that line.

Q. What information did you review in preparing your testimony in this case?

A. I reviewed Entergy's application to build the BPS, the accompanying testimony and exhibits, and Entergy's discovery responses that had been served in this docket at the time I wrote this testimony.

<u>I. Entergy's economic analysis is flawed</u>

Q. What economic analysis does Entergy present in its testimony?

A. Witness Nguyen's direct testimony presents economic analysis comparing the proposed BPS Reciprocating Internal Combustion Engines ("RICE") against a transmission alternative that involves rebuilding the Golden Meadow-Barataria transmission line and converting that line and an existing line to 230 kV operation.

Q. What are the components of the economic analysis Entergy presents?

A. As shown in Figure 3 on page 6 of Witness Nguyen's direct testimony,[1] Entergy begins with an estimated [[[redacted]]] revenue requirement for the proposed BPS and its associated interconnection costs. Entergy then subtracts [[[redacted]]] for the "[v]alue of capacity," i.e., BPS's contribution to meeting peak demand needs.[2] Entergy next subtracts [[[redacted]]] i.e. energy value when BPS can profitably generate.[3] This results in a net cost for BPS of [[[redacted]]], which Entergy claims "is approximately on par with the cost of the transmission alternative under reference assumptions" at Entergy's estimated [[[redacted]]] cost for the transmission alternative.[4,5]

Q. Are Entergy's calculations reasonable?

A. No. Correcting several significant errors in Entergy's economic analysis greatly reduces both the value of BPS and the cost of the "transmission option" alternative. Correcting these errors makes the transmission option economically superior to the proposed BPS. The other transmission alternative discussed in the final section of my testimony would also likely be superior to BPS once these errors are corrected.

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[1] Direct Testimony of Phong D. Nguyen, at 6 (Mar. 5, 2024) ("Nguyen Direct Testimony").
[2] Nguyen Direct Testimony at 8.
[3] Entergy response to AAE 3-27 (noting that Entergy's economic analysis measures "energy benefits associated with BPS").
[4] Nguyen Direct Testimony at 6.
[5] All figures in Entergy's analysis and the revised analysis presented below are net present value ("NPV") estimates, and are in 2028 dollars.

A. Errors in estimating capacity value of BPS

Q. Are the assumptions Entergy used to estimate the capacity value of BPS reasonable?

A. No. Entergy bases its calculation on an inflated cost estimate for building a new combustion turbine ("CT") that is drastically higher than MISO's estimate for the cost of a new combustion turbine.[6] MISO's estimated cost to build a new combustion turbine in the zone that encompasses Louisiana and parts of Texas (Zone 9) is $112,804/MW-year for 2024/2025.[7] Entergy assumes [[[redacted]]] If one estimated the value of BPS's capacity based on MISO's estimate for the cost of a new combustion turbine, this [[[redacted]]]

Q. What factors may have contributed to Entergy's overestimate of the cost of a combustion turbine?

A. First, in response to discovery, Entergy discloses that its cost assumption for a combustion turbine is now [[[redacted]]] than when Entergy conducted the economic analysis for this case.[9] Second, Entergy discloses that [[[redacted]]] because costs for building combustion turbines are lower in Louisiana that in most other regions. For example, MISO's cost estimates show the cost of building a combustion turbine in Louisiana is much lower than nearly all other zones in MISO, and more than 14% lower than some zones.

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[6] Nguyen Direct Testimony at 8.

[7] MISO, *Planning Resource Auction Results for Planning Year 2024-25*, at 26 (Apr. 25, 2024), https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf. Cost of New Entry ("CONE") was set in October 2023.

[8] Entergy response to Staff 2-57, "Staff 2-57 BP24 Avoided Capacity Cost Curves YE 2022 - 240223_HSPM."

[9] Entergy response to Staff 4-18d, HSPM.

[10] Entergy response to Staff 4-18a, HSPM.

Q. More fundamentally, is Entergy right to assume that the cost of a new combustion turbine reflects the value of capacity?

A. No. Entergy's assumption that the value of capacity equals the cost of a new combustion turbine rests on the highly uncertain assumptions that (A) new capacity is needed, and (B) a combustion turbine is the lowest cost source of that capacity. Neither of these assumptions are true in this case.

First, as I explain below, low MISO capacity market prices indicate there is no need for additional capacity. Moreover, capacity surpluses are expected to persist in MISO South and Zone 9. In fact, Entergy's preferred portfolio in its 2023 Integrated Resource Plan ("IRP") only calls for adding 2,200 MW nameplate capacity of resources this decade, comprised of 1,200 MW of solar and 1,000 MW of demand response resources,[11] reflecting the lack of need for capacity. As discussed in Section III below, Entergy's BPS application overstates its need for capacity by incorrectly assuming Power Purchase Agreement ("PPA") contracts expire, and potentially overestimating load growth.

Second, as further discussed in Section III, there are lower-cost sources of capacity than a combustion turbine, including demand response and energy efficiency resources, new low-cost resources including renewable and storage resources (which also benefit from federal tax credits), and contracts with existing resources.[12]

This may explain why Entergy confusingly presents the cost of the combustion turbine as a benefit of BPS, instead of as a cost of the transmission alternative. Entergy's testimony appears to claim a combustion turbine is needed in the transmission alternative,[13] but this is not how it is assessed in Entergy's economic analysis. If a new combustion turbine were truly needed in the transmission alternative and the lowest-cost source of capacity, it would

[11] Entergy Louisiana, LLC, *Entergy Louisiana 2023 Integrated Resource Plan*, at 86-87 (May 22, 2023), https://cdn.entergy-louisiana.com/userfiles/content/irp/2023/Combined-Final-Report-05-22-23.pdf ("Entergy 2023 IRP").

[12] Contracts with existing resources could include signing new PPAs or extending existing PPAs with merchant generators, cogeneration facilities, or resources owned by other utilities in MISO, including Cleco, Lafayette Utilities, Louisiana Energy and Power Authority, and Louisiana Generating LLC in Zone 9 alone. Entergy could also contract with resources outside of Zone 9 that are deliverable to Zone 9.

[13] Direct Testimony of Laura K. Beauchamp, at 31 (Mar. 5, 2024) ("Beauchamp Direct Testimony"); Nguyen Direct Testimony at 2.

have been presented on that side of the ledger. Entergy's omission is unsurprising, given that none of the IRP scenarios selected combustion turbine or RICE generators, indicating these peaking gas generators are not needed or economic relative to the lower-cost resources that were selected, like batteries, demand response, energy efficiency, wind, solar, and in some cases natural gas combined cycle generators.[14]

While Entergy including the value of capacity as a BPS benefit instead of a cost of the transmission alternative does not substantively change the comparison, it does mask two of the flaws in Entergy's analysis: (i) the fact that a combustion turbine is not needed or cost-effective, and (ii) Entergy's failure to subtract energy market profits from the cost of the combustion turbine. The latter point is mentioned in my next answer and discussed at length later in this section.

Q. Is there a better method for assessing the value of capacity than the estimated cost of a combustion turbine?

A. Yes. The MISO market price more accurately reflects the value of capacity because this is the price at which Entergy could buy or sell capacity in the market. MISO operates a residual capacity market that allows utilities who have a capacity shortfall to buy from other market participants with excess generating capacity. The price reflects the net cost of providing capacity for the marginal resource that cleared the market, so the price has already been reduced to reflect the energy market profits received by those resources.

In contrast, Entergy's method requires identifying the lowest-cost source of capacity after accounting for energy market profits, which as discussed below relies on highly uncertain assumptions. Quantifying the expected energy market profits to subtract from a generator's cost to isolate its net cost of providing capacity requires production cost modeling, which is highly sensitive to assumptions about fuel costs, load growth, the MISO generation mix, and other factors over the coming decades, as documented below. Those assumptions and steps are not required if one uses MISO capacity market prices for the value of capacity.

[14] Entergy 2023 IRP at 88-91.

To be conservative, my revised economic analysis presents two methods for calculating the value of capacity: one based on MISO's estimate for the cost of building a combustion turbine in Louisiana, and the other based on MISO market prices. BPS is significantly more costly than the transmission alternative under both methods.

Q. What do MISO market prices indicate regarding the value of capacity in Louisiana?

A. Entergy's estimate for BPS's value of capacity (based on its estimated cost of a combustion turbine) is drastically higher than prices in the MISO capacity market zone that includes Louisiana, Zone 9. In MISO's most recent capacity auction, the market clearing price for Zone 9 is under $7,300/MW-year, [[[redacted]]] Adjusting Entergy's estimate based on this difference reduces the value of BPS's capacity to [[[redacted]]]

One can also average MISO capacity prices over a longer period of time. Over the last 10 years, capacity prices in MISO Zone 9[15] averaged under $2,750/MW-year, or [[[redacted]]] This reduces the value of BPS's capacity to [[[redacted]]][16]

Q. Are low capacity market prices likely to persist in MISO Zone 9?

A. Yes, projections indicate capacity surpluses are likely to persist in MISO South, which will keep capacity market prices low. Recent results from the widely-used Organization of MISO States/MISO survey show capacity surpluses in MISO South are likely through 2030, the last year covered by the survey.[17] This survey presents two scenarios for the rate of future generator completions. The first scenario assumes 6.1 GW/year of new capacity

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[15] MISO, *Planning Resource Auction Results for Planning Year 2024-25 [Corrected]*, at 25 (reposted Apr. 26, 2024), https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf..

[16] These revised calculations scale down Entergy's net present value BPS capacity valuation based on the proportion to which Entergy overstates the initial value of capacity. As a result these revisions maintain Entergy's other assumptions, like the assumed escalation rate for the cost of capacity and the use of 2028 dollars in Entergy's analysis.

[17] OMS-MISO, *2024 OMS-MISO Survey Results [Corrected]*, at 23, 25 (reposted June 20, 2024), https://cdn.misoenergy.org/20240620%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation635585.pdf.

is installed MISO-wide, based on "timing estimates from interconnection customers with signed GIA projects" whose "[r]esponses indicate 6.8 GW can be built for P[lanning] Y[ear] 2025/26," which is then adjusted down to 6.1 GW/year because "MISO data shows 90% of GIAs get built."[18] In this scenario, MISO South will have a winter capacity surplus of 5.2 GW above the planning reserve margin and a summer surplus of 3.8 GW above the planning reserve margin in 2030.

In the other scenario, the survey assumes new generators are installed at the much lower rate of 2.3 GW/year that MISO saw in 2020-2022. Those years were marked by extreme disruption of normal generation development timelines and success rates, first due to the global pandemic and then supply chain disruptions and unexpected increases in interest rates. As a result, this scenario can be viewed as an extremely low estimate for the rate at which new resources will be completed going forward. Even in this extreme scenario, MISO South would have a winter capacity deficit of only 0.1 GW in 2030 and a summer capacity deficit of 1.5 GW below the planning reserve margin. If actual capacity additions fall in the middle between those two scenarios, in 2030 MISO South would have a capacity surplus of around 2.5 GW in winter and 1.2 GW in summer.

There is also reason to believe actual generator installations could be higher than the survey's 6.1 GW/year scenario, which assumes that generators interconnect in the years 2026-2030 at the same rate planned for 2025/2026. The federal Inflation Reduction Act, which provides an expanded 30-50% investment tax credit for battery storage and robust production tax credits for wind and solar resources, was only signed into law in August 2022. Consequently, additional projects that entered development in response to that legislation will likely come online later this decade.

Q. Are there other errors in Entergy's analysis?

A. Yes. If one sets the value of capacity based on the cost to build a new combustion turbine, as Entergy does, one must subtract the combustion turbine's energy market profits from the cost of the combustion turbine to isolate its net cost of providing capacity.

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[18] *Id*. at 6.

As noted above, Entergy's analysis uses the cost of a generic combustion turbine to set the value of the capacity provided by BPS. Entergy calculated the energy market profits for BPS (what Entergy labels [[[redacted]]])[19] and subtracted them from its cost, but did not do this for the combustion turbine Entergy used as the basis for calculating BPS's capacity value. This results in an apples-to-oranges comparison that double counts energy market profits on the BPS side of the ledger. This error would have been more obvious if Entergy had put the combustion turbine cost on the cost side of the ledger for the transmission alternative, instead of on the benefit side of the ledger for BPS. In other words, if Entergy subtracted energy market profits from the cost of BPS but not from the cost of a combustion turbine included as part of the transmission alternative, the apples-to-oranges comparison would have been more obvious.

A rough estimate is that a combustion turbine would earn similar profits in the MISO energy market as BPS, as they have similar heat rates and dispatch profiles. Therefore, one can correct this error in Entergy's analysis by [[[redacted]]][20] If one conservatively uses MISO's cost of a new combustion turbine as the value of capacity, [[[redacted]]] Production cost modeling would be required to more precisely project the combustion turbine's energy market profits. While they may be somewhat smaller than the [[[redacted]]] in profits Entergy projected for BPS, they are certainly greater than zero.

Subtracting energy market profits to isolate the net cost of providing capacity also highlights why Entergy's 2023 IRP did not select peaking gas generators like RICE units and combustion turbines.[21] Peaking generators primarily serve as capacity resources, providing much less energy generation and energy market profits than resources with lower fuel costs, like gas combined cycle, renewable, and hybrid renewable-battery generators. As discussed at more length in Section III, Entergy's IRP only selected resources that

[19] Nguyen Direct Testimony at 6, Figure 3.
[20] *Id.*
[21] Entergy 2023 IRP at 88-91.

provide low-cost energy, apparently reflecting (a) that these resources provide capacity at a lower cost than that of peaking gas generators, as well as (b) Entergy's limited need for additional capacity. Another way of interpreting the results of Entergy's IRP is that gas combined cycle, renewable, and hybrid resources being added to meet Entergy's need for energy (MWh) also provide enough capacity to meet Entergy's peak load needs (MW), so peaking gas resources are not needed.

Q. Can you please summarize how using these more reasonable assumptions for the value of BPS's capacity change the results of Entergy's economic analysis?

A. With any of the revisions outlined above, BPS is significantly more expensive than the transmission alternative. As shown in the right-most column of Table 1 below, even conservatively using MISO's estimate for the cost of a new combustion turbine ("CT") as the value of BPS's capacity, the transmission alternative would be [[[redacted]]] less costly than BPS, and [[[redacted]]] less costly if the combustion turbine's energy market profits are correctly subtracted from its cost. If MISO capacity market prices are used as the value of BPS's capacity, the transmission alternative would save Entergy ratepayers more than [[[redacted]]].

Table 1: Revised analysis with corrected value of BPS capacity (NPV in 2028 $millions) (HSPM)

[redacted]

B. Entergy's errors in estimating the cost of the transmission alternative

Q. Is Entergy's estimate cost of the transmission alternative reasonable?

A. No, for several reasons. First, Entergy included large investments to increase transmission voltage to meet load growth that are likely unnecessary in the near-term, particularly if modular deployments of demand response or batteries or incremental grid upgrades are used to defer the need for upgrades.

In addition, Entergy's cost estimate for building the Golden Meadow ("GM")-Barataria line appears to be high. To be conservative, that cost estimate is not revised in my analysis, and the transmission alternative is already clearly economically superior to Entergy's BPS proposal. However, the Commission should direct Entergy to conduct a competitive bidding process for the construction and materials for the transmission project, and bring in an independent consultant to review Entergy's engineering and materials estimates for the project.

Q. Did Entergy break down the components of the transmission alternative?

A. Entergy broke down the $307 million investment for the transmission alternative as follows:

> "GM-Barataria Line Rebuild: $210 million
>
> Clovelly Capacitor Bank: $4 million
>
> GM-Barataria Conversion to 230 kV [kiloVolt] Operation: $54 million
>
> Valentine-Clovelly-GM Conversion to 230 kV Operation: $39 million"[22]

Q. Did Entergy disclose at what levels of load growth these upgrades are needed?

A. In response to discovery, Entergy disclosed the following thresholds for local load growth that would trigger the need for each of the upgrades identified above:

> [[[redacted]

[22] Direct Testimony of Samrat Datta, at 29 (Mar. 5, 2024) ("Datta Direct Testimony").

[redacted]]]

The ranges reflect possible ranges for the power factor of the load [[[redacted]]][24] Data provided elsewhere in discovery indicates that the current power factor for the local loads at the Valentine, Clovelly, Golden Meadow, Leeville, Fourchon, and Louisiana Offshore Oil Platform ("LOOP") substations is [[[redacted]]][25] As a result, the MW threshold for triggering upgrades is likely on the higher end of the ranges Entergy identified.

Q. Are the 230 kV conversions necessary?

A. No. At least one, and probably both, of the 230 kV conversions are unnecessary. First, Entergy has failed to establish that load growth in the local area will reach the high levels it indicated are necessary to trigger the 230 kV upgrades. Second, Entergy could likely implement incremental transmission upgrades, particularly as part of the Golden Meadow-Barataria rebuild, to meet load growth. Third, incremental additions of modular resources in the local area, like demand response or battery storage, could at least defer if not permanently replace the need for the 230 kV conversions. As noted below, Entergy admits that it did not evaluate the use of these incremental solutions as part of a transmission alternative.[26]

Removing both 230 kV conversions reduces the cost of the transmission alternative by $93 million, further improving its economics relative to Entergy's BPS proposal. At minimum these conversions could be deferred, saving Entergy ratepayers significant expense in the

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[23] Entergy response to Staff 2-51, HSPM (attached as Exhibit MG-2).
[24] Power factors less than 1 consume reactive power, and transmitting reactive power to those loads uses up available transmission capacity.
[25] Entergy response to LEUG 1-3, "Power Barge Microgrid Loading-HSPM", tab "23U0 - Non-Coincident Loads," HSPM.
[26] Entergy response to AAE 6-7 (attached as Exhibit MG-3).

near-term. In the unlikely event that large local load growth does materialize, the conversions could then be implemented at a much lower net present value cost due to the discount rate.

The cost of the transmission alternative could potentially be reduced even further if Golden Meadow-Barataria does not need to be built with the capability of operating at 230 kV,[27] which would likely reduce the cost of the conductor, structures, insulators, and their associated construction. However, to be conservative my revised economic analysis uses Entergy's cost estimate for this line rebuild.

Q. Are the load growth levels required to trigger the 230 kV conversions large?

A. Yes. Taking the middle of the [[[redacted]]] range provided by Entergy as necessary to trigger the Golden Meadow-Barataria 230 kV conversion,[28] [[[redacted]]][29] Similarly, [[[redacted]]] of load growth, the middle of the [[[redacted]]] range Entergy indicated would trigger the Valentine-Clovelly-Golden Meadow conversion to 230 kV,[30] represents about [[[redacted]]][31]

Q. What level of load growth does Entergy project for the area?

A. For the sum of the Valentine, Clovelly, Golden Meadow, Leeville, Fourchon, and LOOP substations, Entergy projects coincident summer peak load increasing from [[[redacted]]][32] This increase of [[[redacted]]] is much lower than the levels necessary to trigger a need for either of the 230 kV conversions. The $4 million cost for the Clovelly capacitor bank that Entergy indicated is needed to accommodate [[[redacted]]] of load growth may

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[27] Datta Direct Testimony at 7.
[28] Entergy response to Staff 2-51, HSPM.
[29] Entergy response to LEUG 1-3, "Power Barge Microgrid Loading-HSPM," tab "Summary - Summer & Winter Peaks," summing cells N3-N8 HSPM.
[30] Entergy response to Staff 2-51, HSPM.
[31] Entergy response to LEUG 1-3, "Power Barge Microgrid Loading-HSPM," tab "Summary - Summer & Winter Peaks" summing cells N3-N8, HSPM.
[32] *Id.*

also be unnecessary, though to be conservative I have not removed it in my revised cost analysis.

Q. What has been the recent trend in load in the local area?

A. Historical data summing peak load for the Valentine, Clovelly, Golden Meadow, Leeville, and Fourchon substations,[33] presented in Figure 1 below, does not show an upward trend in load over the last five years. If anything, the chart appears to show a steady downward trend in peak load, aside from brief anomalies in [[[redacted]]] Entergy did not provide historical load data for the LOOP substation so it is not included in the chart below, but Entergy projects [[[redacted]]][34]

[33] *Id.*
[34] *Id.*

[redacted]

Figure 1: Historical sum of coincident peak load at Valentine, Clovelly, Golden Meadow, Leeville, and Fourchon substations (HSPM)

Q. What long-term factors may affect local load trends?

A. There are two factors, in particular, that could depress load in this region. First, Gulf of Mexico fossil fuel production and imports are declining. This may not only affect the industrial loads associated with the fossil fuel industry, but the entire local economy including the commercial and residential loads directly and indirectly related to the industry. Offshore gas production in the Gulf of Mexico has been in long-term decline, with production on federal leases steadily falling 85% from 5 trillion cubic feet in 2001, to 0.7 trillion cubic feet in 2022,[35] as offshore production cannot compete with land-based production using horizontal drilling, hydraulic fracturing, and other unconventional production techniques. Offshore oil production may experience a similar fate as it faces

[35] U.S. Energy Info. Admin., *Natural Gas Data: Federal Offshore – Gulf of Mexico Natural Gas Production* (Aug. 30, 2024), https://www.eia.gov/dnav/ng/hist/na1160_r3fm_2A.htm.

competition from lower-cost non-conventional production on land. LOOP is primarily used for supertanker deliveries of oil imports, and U.S. oil imports are also in long-term decline, falling by 36% since 2005,[36] as imports are displaced by domestic unconventional production. Second, sea level rise is particularly pronounced in the local area,[37] which may drive long-term reductions in the population and thus electricity demand.

Q. If load growth does materialize, could Entergy use smaller grid upgrades than the proposed 230 kV conversions?

A. Yes, incremental transmission upgrades, particularly as part of the Golden Meadow-Barataria rebuild, could likely meet smaller amounts of load growth at lower cost. For example, the line's thermal capacity can be increased by using higher quality conductors to reduce sag or using taller structures for some segments to increase clearance. Greater deployment of reactive devices, including series compensation devices along transmission lines, can also be used to improve their transfer capacity and address stability or voltage concerns. While detailed engineering analysis would be required to design and find the optimal mix of these solutions, these tailored solutions are likely to offer a lower cost for meeting an incremental load growth need.[38] Entergy proposes a large lumpy investment in converting lines to operate at 230 kV, which results in unnecessary capacity increases that inflate the cost of its transmission alternative.

Q. Can small additions of modular resources in the local area, like demand response or battery storage, meet incremental load growth needs?

A. Yes, modular deployments of resources like demand response and battery storage are likely to be a lower-cost solution for meeting an incremental load growth need. This conclusion is supported by the economic selection of these resources in Entergy's IRP and the cost data for batteries presented in Section III below. Both resources are highly modular in that

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[36] U.S. Energy Info. Admin., *Petroleum & Other Liquids Data* (Aug. 30, 2024), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrimus1&f=a.

[37] U.S. Climate Resilience Toolkit, *Grand Isle: Louisiana's First Line of Defense from Coastal Flooding*, (May 2024), https://toolkit.climate.gov/case-studies/grand-isle-louisianas-first-line-defense-coastal-flooding.

[38] This conclusion is informed by the relatively low $4 million cost Entergy estimated for installing a capacitor bank at Clovelly, per Datta Direct Testimony at 29.

the quantity and location of the resource and its service can be precisely tailored to the need, minimizing costs, unlike the lumpy investment proposed by Entergy. Batteries and demand response resources can alleviate transmission constraints by shifting peak loads to times when transmission capacity is available, in addition to providing Entergy with capacity to meet system-wide peak demand. The other reliability benefits of batteries are discussed in more detail in the next section of my testimony. Given that Entergy has indicated it did not assess how these solutions could complement a transmission alternative,[39] the Commission should require Entergy to conduct more detailed analysis and quantify the cost of that solution.

Demand response can involve compensating large but non-essential industrial loads to reduce demand during peak times or contingency conditions. It can also involve reducing grid load during peak periods using the backup generator capacity that many essential loads already have onsite. For example, Port Fourchon[40] and LOOP[41] both have backup generation that they have relied on to meet a large share of their needs when the local transmission system was unavailable due to hurricane damage.

Despite their potential significance, Entergy has not analyzed these backup generation resources. In response to Staff data requests 2-6 and 2-7, Entergy indicated it does not know and has not evaluated the quantity or capacity of backup capacity in the area.[42] This also calls into question the claimed resilience benefits of Entergy's BPS microgrid proposal, as at least some of the critical loads that Entergy discusses in its application already have backup generation supplies. These resilience issues are further discussed in Section II below.

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[39] Entergy response to AAE 6-7 (attached as Exhibit MG-3).
[40] C. Martin, *Louisiana Port May Resume Some Oil Deliveries Within a Week*, The Oildrum (Sept. 8, 2008) http://theoildrum.com/node/4480#comment-402402.
[41] *Little damage at Louisiana oil port*, The Columbus Dispatch (Aug. 30, 2012), https://www.dispatch.com/story/news/environment/2012/08/30/little-damage-at-louisiana-oil/23473508007/.
[42] Entergy responses to Staff 2-6 and 2-7 (attached as Exhibit MG-4).

Q. Do you have other concerns with Entergy's cost assumptions for the transmission alternative?

A. Yes. Entergy's cost assumptions for building the Golden Meadow-Barataria line appear high. To be conservative, that cost estimate is not revised in my quantative analysis, and as discussed above the transmission alternative is already clearly economically superior to Entergy's BPS proposal. Nevertheless, I believe the cost estimate for this line is likely inflated.

Under normal conditions, building 31 miles of new 115 kV transmission should cost around $68 million at MISO's estimate for Louisiana of $2.2 million per mile.[43] Admittedly, the cost of Golden Meadow-Barataria is likely to be higher than average because of the terrain and other construction challenges, and MISO's estimate is in 2024 dollars while Entergy's is in 2028 dollars, but at $210 million Entergy's estimate is 3 times higher than MISO's estimate for a typical 115 kV line.

As the transmission owner, Entergy has asymmetric information about and a large degree of control over the cost of the transmission alternative. Confirming the extent to which Entergy controlled the cost estimate for the transmission alternative, Witness Datta presents the cost estimate for the Golden Meadow-Barataria line as an estimate informed by "preliminary engineering by internal resources, a detailed internal estimate of all material costs with input from all material vendors" plus what appears to be a single bid for the construction.[44] The Commission should direct Entergy to conduct a competitive bidding process and bring in an independent consultant to review Entergy's engineering and materials estimates for this transmission project.

Again, even though Entergy's cost estimate for Golden Meadow-Barataria is likely inflated, to be conservative, I did not revise Entergy's estimate in my economic analysis. Doing so would not change the outcome because, even using Entergy's cost estimate, the transmission alternative still costs much less than the BPS.

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[43] MISO, *Transmission Cost Estimation Guide For MTEP24*, at 38 (May 1, 2024), https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf.
[44] Datta Direct Testimony at 28.

Q. Please summarize how the downward revisions in both the cost of the transmission alternative and in the value of BPS change the results of Entergy's economic analysis.

A. Removing the unnecessary 230 kV conversions reduces the upfront cost of the transmission alternative by 30.3% from $307 million to $214 million. Scaling the net present value cost of the transmission alternative down by 30.3% reduces it from [[[redacted]]].[45]

With reductions in both the value of BPS and the cost of the transmission alternative, the transmission alternative is clearly economically superior, as shown in the right-most column of Table 2 below. Even if one does not correct the errors in Entergy's estimate of BPS's capacity value, correcting the cost of the transmission alternative alone shows it provides [[[redacted]]] in savings for Entergy ratepayers. If one reduces both the BPS capacity value and the cost of the transmission alternative, the transmission alternative saves ratepayers as much as [[[redacted]]] relative to Entergy's proposed BPS.

Table 2: Revised analysis with corrected cost of transmission alternative under various assumptions for BPS capacity value (NPV in 2028 $millions) (HSPM)

[redacted]

[45] Scaling the net present value by 30.3% preserves the financial assumptions Entergy used to convert the cost of the transmission alternative to a net present value.

Q. Based on the magnitude of the savings from the transmission alternative, are there factors or uncertainties that could result in the transmission alternative being more expensive than BPS?

A. No. Entergy notes uncertainties about the cost of the transmission alternative, differences related to insurance between BPS and the transmission alternative, and the potential that BPS could qualify for the Louisiana Industrial Tax Exemption Program. However, none of these factors could be large enough to change the outcome of the analysis: the transmission alternative is economically superior to BPS.

Regarding insurance, Entergy notes that "the transmission alternative includes minimal insurance cost due to the unavailability of casualty insurance for most of the transmission assets."[46] However, an insurance premium cost for the transmission alternative is included in Entergy's analysis, totaling [[[redacted]]][47]

Witness Nguyen's testimony shows a [[[redacted]]] improvement in the net present value cost of BPS under a sensitivity in which it receives property tax abatement under the Louisiana Industrial Tax Exemption Program.[48] Even if BPS does receive that exemption, it would still be much more costly than the transmission alternative.

C. Entergy used unrealistic assumptions to estimate BPS's energy value

Q. Are there other problems with Entergy's estimate for the energy market profits the BPS can earn?

A. Yes. Entergy used a number of questionable assumptions in its modeling of BPS's projected energy market profits. To be conservative, none of these assumptions are changed in the revised economic analysis presented above. However, these problematic

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[46] Nguyen Direct Testimony at 3.
[47] Entergy response to Staff 2-57 "GM-B Xsmn Rev Req_HSPM.xlsm," tab "Rev Req - Transmission 1," cells AA39:BD39, HSPM.
[48] Nguyen Direct Testimony at 7.

assumptions raise serious questions about Entergy's estimate that BPS can earn [[[redacted]]] in energy market profits.

Q. How are BPS's economics affected by uncertainty about fuel and carbon prices?

A. Entergy estimated BPS's energy value using production cost modeling, which is highly sensitive to projections for future fuel and carbon prices. Entergy's analysis confirms that BPS's economics are highly sensitive to assumed fuel prices. Entergy's results indicate that its claimed savings of [[[redacted]]] for the BPS in a scenario with low gas prices and no carbon price.[49] This appears to occur primarily because low gas prices reduce BPS's profit margin during market intervals when combustion turbine units are setting the market clearing price.

Current natural gas futures are trading at prices that are closest to, and in some cases below,[50] the assumed prices in the low gas price scenario.[51] As a result, even with its flawed assumptions, Entergy's own analysis suggests BPS is uneconomic relative to the transmission alternative.

Q. Were the other assumptions used in Entergy's production cost modeling reasonable?

A. No. As noted above, production cost modeling is sensitive to assumptions about future fuel and carbon prices. This type of modeling is also highly sensitive to assumptions about the future generation mix in MISO and MISO South, including the mix of gas versus coal generation, the growth of renewable generation, and the overall capacity position in the market relative to load.

As noted above, there is a large capacity surplus in Zone 9 and MISO South generally, which will reduce the number of hours in which BPS can profitably generate in the market. The abundance of resources with a lower heat rate and thus lower cost of generation makes

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[49] Nguyen Direct Testimony at 7.
[50] Barchart, *Natural Gas Oct '24* , https://www.barchart.com/futures/quotes/NG*0/futures-prices (last accessed Sept. 9, 2024).
[51] Nguyen Direct Testimony at 5.

it difficult for BPS to compete in the market. Entergy's estimated capacity factor [[[redacted]]][52] for BPS is extremely high for a RICE unit whose heat rate and thus fuel cost is significantly higher than these other resources, primarily the combined cycle generators that make up more than half of the generating capacity in MISO South[53] and provide most of the generation.

Q. Are Entergy's projections for renewable and storage penetrations in MISO reasonable?

A. No. Entergy's assumptions for future renewable penetrations[54] are significantly lower than those in MISO's Futures,[55] which are the economically modeled results MISO uses for its planning. Renewable resources reduce electricity prices because, as fuel-free resources, their variable costs are very low. For example, analysis by Lawrence Berkeley National Laboratory confirms a negative correlation between renewable penetrations and wholesale power prices.[56] At locations and times when renewable resources are the marginal resource and set the market clearing price, their impact can be even larger because renewable resources receive federal production tax credits that allow them to offer at negative prices. Because Entergy underestimates renewable growth in MISO and MISO South, the analysis greatly overestimates the revenue and profit BPS can earn in the MISO market.

MISO's Future 1A, the most conservative of MISO's projections, projects 82 GW of wind and 84 GW of solar across MISO by 2042.[57] Expected renewable capacity is drastically higher in Future 2A, which includes 162 GW of wind and 112 GW of solar in 2042.[58] In contrast, Entergy projects [[[redacted]

[52] Direct Testimony of Gary C. Dickens (Mar. 5, 2024) ("Dickens Direct Testimony"), Exhibit GCD-7. HSPM
[53] MISO, *2023 MISO Transmission Expansion Plan*, at 121 (2023), https://cdn.misoenergy.org/MTEP23%20Full%20Report630587.pdf ("Approximately 53% (20.2 GW) of the South region's generation capacity is made up of combined cycle (CC) units").
[54] Entergy response to AAE 6-28 HSPM.
[55] MISO, *MISO Futures Report Series 1A* (Nov. 1, 2023), https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf ("MISO Futures Report Series 1A").
[56] Joachin Seel et al., *Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making*, Lawrence Berkeley National Lab (May 2018), https://emp.lbl.gov/publications/impacts-high-variable-renewable.
[57] MISO Futures Report Series 1A at 59.
[58] *Id.* at 76.

[redacted]]],[59] excluding Entergy's proposed build of 9,300 MW of renewables.[60] Thus, while MISO's Tranche 1A projection is for 166 GW of renewables by 2042, Entergy expects just [[[redacted]]] less than MISO's lowest projection.

MISO's projections for battery capacity are also markedly higher than Entergy's, and batteries directly compete against BPS for providing flexible generation. As a result, Entergy's analysis underestimated the extent to which more flexible batteries will keep prices low in the MISO market by responding to short-term needs for energy and flexibility. MISO projects adding 10,800 MW of batteries in Future 1A, 31,100 MW in Future 2A, and 39,600 MW in Future 3A.[61] In contrast, Entergy projects the rest of MISO reaching only [[[redacted]]],[62] plus 450 MW of Entergy's own battery additions,[63] for a total of less than [[[redacted]]] less than MISO's lowest forecast.

Q. Are Entergy's projections for renewable and storage penetrations in MISO South reasonable?

A. No. The difference between Entergy and MISO projections is even more pronounced in MISO South. Because of limited transmission ties between MISO South and the rest of MISO, renewable and storage resources in MISO South cause a much larger reduction in market prices and thus the profit realized by BPS than resources in other parts of MISO. Entergy's projections for the rest of MISO South include [[[redacted]]],[64] which combined with Entergy's planned build results in just [[[redacted]]]. In Future 1A, MISO projects adding more than 4,000 MW of batteries in MISO South by 2042, as well as more than 28,500 MW of solar (inclusive of distributed solar PV), 16,800 MW of wind, and 2,200

[59] Entergy response to AAE 6-28 HSPM.
[60] Entergy 2023 IRP at 93.
[61] MISO Futures Report Series 1A at 55.
[62] Entergy response to AAE 6-28 HSPM.
[63] Entergy 2023 IRP at 93.
[64] Entergy response to AAE 6-28 HSPM.

MW of hybrid resources.[65] Under Future 2A, that increases to more than 8,000 MW of batteries, more than 33,000 MW of solar, and nearly 3,000 MW of hybrid resources.[66]

Q. Did Entergy's production cost modeling capture how local transmission constraints could reduce the value of BPS's generation?

A. No. Entergy's Aurora analysis was also based on a simplified zonal model and not a detailed nodal model of the MISO market,[67] so it would have missed localized transmission congestion that could reduce the value of BPS's generation. Solar plants tend to be built as far south as possible to take advantage of better solar resources, so southern Louisiana is likely to be the optimal location for solar generation across all of MISO. Several GW of inflexible nuclear and gas generation at the Waterford, Little Gypsy, St. Charles, Taft Cogeneration, and Dow St. Charles Cogeneration plants west of New Orleans will have difficulty reducing their output in response to daily swings in solar output, potentially causing low locational marginal prices that extend back to BPS if local transmission congestion prevents the output of those plants from reaching demand centers like New Orleans. Nuclear and some cogeneration resources tend to bid into wholesale electricity markets at low or negative prices to reflect their inflexibility, so they can set low market clearing prices.

Q. Were these flaws accounted for in your revised economic analysis?

A. To be conservative, none of these shortcomings in Entergy's Aurora modeling were accounted for in my analysis. However, if Entergy had used more realistic assumptions for the MISO generation mix and transmission constraints, the projected energy value of BPS would likely be significantly lower than Entergy's estimate of [[[redacted]]].

Entergy may have also understated the fixed O&M costs associated with BPS, as discussed in more detail in Section III below. To be conservative, this assumption is also not revised in my analysis. Again, even without using more realistic assumptions for MISO generation

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[65] MISO, Futures Report Series 1A at 70.
[66] *Id.* at 87.
[67] Entergy public response to AAE 6-29a ("A zonal representation was used in the Aurora modeling.").

mix, transmission constraints, and O&M costs, BPS is clearly uneconomic relative to alternatives.

II. BPS is not the best solution for Entergy's claimed reliability and resilience need

Q. How does Entergy present the need for BPS?

A. Throughout its application, Entergy focuses on the BPS microgrid as the best solution to claimed reliability and resilience needs, primarily related to critical oil and gas customers in the local area.[68]

Q. Is this accurate?

A. No. During a disturbance, the BPS microgrid fails to maintain electric service to customers, who will experience an outage of unknown duration. In contrast, transmission provides a range of reliability services instantly, so under the transmission alternative electric service can be maintained during and after a system disturbance. As a result, Entergy is wrong in claiming that "the transmission alternative is not directly comparable to BPS and has certain disadvantages relative to BPS in terms of maintaining grid reliability."[69] Moreover, many critical customers will see little value from the BPS microgrid because they already have backup generation.

Q. Please compare the reliability and resilience of Entergy's BPS microgrid proposal against the transmission alternative.

A. Under Entergy's BPS microgrid proposal, customers would experience a blackout every time the single circuit serving customers experiences an outage. In contrast, the transmission alternative involves two circuits serving load, so the second circuit is the backup if the other circuit is lost. For many customers, a large share of their total costs of

[68] For example, see the Beauchamp Direct Testimony at 37, and the entire Direct Testimony of Sean Meredith (Mar. 5, 2024).
[69] Nguyen Direct Testimony at 6 n.3.

an outage are incurred in the initial moments of the outage.[70] Even momentary power disruptions can be extremely costly for customers with sensitive equipment or processes.

Customers served by the proposed BPS microgrid proposal would experience a blackout and then go through a potentially lengthy and risky load restoration process. When asked in discovery, Entergy confirms that its BPS microgrid proposal calls for customers to experience a blackout and then gradually have service restored.[71] This blackout for microgrid customers is necessary under Entergy's proposal because the BPS generator cannot start fast enough to maintain reliable service. In contrast, transmission provides a range of reliability services instantly, so the lights can be kept on during and after a system disturbance.

In response to discovery, Entergy also admitted that "the Company does not have an estimate of the range of load restoration timelines that are expected for the microgrid."[72] It also appears that some critical loads will be among the last restored, per the statement in the microgrid design specifications that [[[redacted]]][73]

Q. Can you compare how BPS and the transmission alternative would fare in restoring power following a localized blackout?

A. The transmission alternative is a more reliable and resilient solution than the proposed BPS. Under the transmission alternative, blackouts would not be necessary following the loss of a transmission circuit because the other circuit would instantly pick up the load and provide reliability services without a need to start up, as explained above. However, in the event a hurricane or other event causes a localized blackout and load must be restored, transmission lines are also superior to the BPS microgrid. Transmission delivers the full suite of

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[70] M. Sullivan et al., *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, Lawrence Berkeley National Lab, at xii (Jan. 2015), https://live-lbl-eta-publications.pantheonsite.io/sites/default/files/lbnl-6941e.pdf.
[71] Entergy response to AAE 7-1a (attached as Exhibit MG-5) (when asked to "confirm that the proposed microgrid functioning as intended will involve the load served by the microgrid being interrupted and then restored," Entergy responded "Yes, that is correct").
[72] Entergy response to AAE 7-1b (attached as Exhibit MG-5).
[73] Entergy response to AAE 4-11 (HSPM).

reliability services, including instantly balancing supply and demand and flexibly responding to evolving grid needs by tapping into the vast supply of reliability services provided by resources across the Eastern Interconnection.

In contrast, BPS may struggle to balance supply and demand on the microgrid, particularly as large loads start up. Concerningly, Entergy notes that this would be its first microgrid,[74] and the large motor loads served by the proposed microgrid pose unique challenges. Resulting swings in voltage, frequency, and phase angle can damage sensitive equipment at loads or generators. For this reason, most load restorations on mainland power systems primarily rely on transmission connections instead of islanding with blackstart resources. Entergy noted this fact in explaining its use of transmission, rather than a RICE generating facility similar to BPS, to restore load in New Orleans following Hurricane Ida.[75] Entergy stated that "It is more reliable and safer to operate a power plant in conjunction with a transmission line in service, rather than in an 'island' configuration."[76]

Q. In the preceding section you mentioned that batteries could help meet load growth or other local reliability needs under the transmission alternative. What reliability services can batteries provide?

A. As noted previously, batteries can help meet local load growth or other reliability needs, particularly as part of a transmission alternative. Batteries can work with the transmission to meet local load growth by shifting peak loads to times when transmission capacity is available. Batteries offer high capacity value[77] for meeting local and system peak demand needs, comparable to that offered by conventional generators. Even short-duration batteries can meet peak demand needs as peaks also have a short duration, typically no more than several hours. As more solar resources come online, peak net load periods are actually

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[74] Entergy response to LPSC Staff 2-65.
[75] The New Orleans Power Station uses the same equipment as Entergy has proposed for BPS.
[76] Entergy, *Frequently Asked Questions About New Orleans Power Station*, https://www.entergy.com/brightfuturenola/nopsfaq/ (last visited Sept. 5, 2024) (attached as Exhibit MG-6).
[77] Paul Denholm et al., *The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States*, National Renewable Energy Laboratory (NREL), at 8 (June 2019), https://www.nrel.gov/docs/fy19osti/74184.pdf.

shortening as afternoon solar output meets the early part of the afternoon-to-evening peak.[78]

Q. How do the reliability services contributions of batteries compare to RICE units like BPS?

A. A battery is more flexible than BPS, making it more valuable for meeting both local and system-wide reliability needs, particularly in a high renewable penetration future. Relative to RICE units, batteries have a much faster startup and shutdown time, no minimum output level or duration, and the ability to absorb excess power by charging. Batteries can typically meet reactive, voltage, and stability needs within seconds or less, including responding to contingencies such as the failure of a transmission line or generator.[79] This allows batteries to defer or reduce the need for grid upgrades triggered by local contingency, stability, or voltage and reactive power needs. Battery storage resources are highly modular and have a small footprint, so they can be optimally sized and located to meet local reliability needs.

If Entergy needs enhanced local reliability services, such as contributing to short circuit strength to support motor starting loads, for a modest cost premium a grid-forming battery could be installed. Grid-forming converters can set voltage and frequency signals and thus contribute more to system stability and short circuit strength than grid-following converters, which follow the voltage and frequency signals set by other resources.[80]

If needed, solar can also be installed to help meet the energy need and some of the capacity need from local load growth, while a battery helps meet the capacity need. There are large synergies between solar and batteries, as solar increases the capacity value of batteries by shortening the duration of peak net load periods, and batteries' flexibility can help with daily ramps in solar output. Solar plants also contribute to local voltage and reactive

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[78] *Id.* at 12. For another example, see E3, *Capacity and Reliability Planning in the Era of Decarbonization*, at 6 (August 2020), https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf.
[79] See Brent Oberlin, *Storage as a Transmission Only Asset*, at 11-15 (May 2022), https://www.iso-ne.com/static-assets/documents/2022/05/a7_storage_as_a_transmission_only_asset.pdf; and
William Brown et al., *Storage as Transmission Asset Market Study*, Quanta Technology (Jan. 2023), https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf.
[80] Julia Matevosyan & Jason MacDowell, *Grid-Forming Technology in Energy Systems Integration, ESIG Energy Systems Integration Group*, at 10-11 (Mar. 2022),https://www.esig.energy/wp-content/uploads/2022/03/ESIG-GFM-report-2022.pdf.

support, as pursuant to FERC Order 827 (issued in 2016) all solar, battery, and wind plants now match the reactive and voltage support contributions of conventional generators.[81]

Given that Entergy did not assess how battery, solar, and demand response solutions could complement a transmission alternative,[82] the Commission should require Entergy to conduct more detailed analysis and quantify the cost of potential solutions.

Q. Which is more useful on a power system with a high renewable penetration: a battery or a RICE unit?

A. A battery is far more useful, particularly for power systems with high solar penetrations. Unlike gas generators, batteries can absorb midday solar generation that would have been curtailed. Because they can ramp from full charging to full discharging, batteries also offer twice the flexible ramp range as gas generators. This is particularly valuable for meeting morning and evening net load ramps as the sun rises and sets.

The ability of RICE units to start up quickly is not particularly helpful for accommodating high solar penetrations. This misconception appears throughout the testimony supporting Entergy's application.[83] While the passage of clouds can cause rapid and uncertain changes in the output of a single solar plant, it has a trivial impact on the output of a large fleet of solar plants because geographic diversity ensures they are not affected by the same clouds at the same time.[84]

Q. Are there risks that BPS may not be available when needed for local or system-wide reliability needs?

A. Yes. Gas generators across MISO South experienced correlated outages during Winter Storms Uri, Elliott, and a 2018 cold snap event. Entergy indicates it has executed a Precedent Agreement for firm transportation service on Tennessee Gas Pipeline.[85]

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[81] FERC, *Reactive Power Requirements for Non-Synchronous Generation*, 155 FERC ¶ 61,277 (June 16, 2016), https://www.ferc.gov/sites/default/files/2020-06/RM16-1-000.pdf.
[82] Entergy response to AAE 6-7 (attached as Exhibit MG-3).
[83] For example, see Datta Direct Testimony at 14-17.
[84] Andrew D. Mills & Ryan H. Wiser, *Implications of geographic diversity for short-term variability and predictability of solar power*, Lawrence Berkeley National Lab (2011), https://www.osti.gov/servlets/purl/1196768.
[85] Entergy Response to LPSC 2-26.

Although having a firm transporation agreement is helpful, it does not mitigate all risks of correlated outages.

Pipelines can experience disruptions of firm service due to weather events, accidents, and malicious attacks. Tennessee Gas Pipeline was offline for months following Hurricanes Katrina and Rita.[86] More recently, Force Majeure events were declared for Tennessee Gas Pipeline segments in Louisiana during Hurricanes Delta and Laura in 2020.[87]

Gas generators are also subject to correlated equipment failures, particularly during cold snap events. The New Orleans Power Station ("NOPS"), which uses the same equipment Entergy proposes to use for BPS, has seen a forced outage rate [[[redacted]]].[88] Moreover, Entergy's own May 2023 IRP concerningly notes that RICE units tend to have higher actual forced outage rates than projected.[89]

In contrast, Entergy indicates that the forced outage rate of its 230 kV transmission lines over the last four years has averaged [[[redacted]]]. As a result, the transmission alternative, with a transmission circuit serving as the backup for another transmission circuit, would be much more reliable and resilient than Entergy's proposal of a gas generator serving as the backup for a single transmission circuit. This is the case without even accounting for the fact that under Entergy's proposal BPS microgrid customers would experience a blackout every time the transmission line experienced an unexpected outage.

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[86] NGI, *Tennessee Expects to Restore Gas Supply to 85% of Pre-Hurricane Levels by December* (Oct. 13, 2005), https://naturalgasintel.com/news/tennessee-expects-to-restore-gas-supply-to-85-of-pre-hurricane-levels-by-december/.

[87] Tennessee Gas Pipeline Company, *FORCE MAJEURE FOR STA 823 EFFECTIVE FRIDAY, OCTOBER 9, 2020* (Aug. 31, 2020), https://pipeline2.kindermorgan.com/Notices/NoticeDetail.aspx?code=TGP&notc_nbr=376652; Tennessee Gas Pipeline Company, *FORCE MAJEURE AT STA 823 RESOLVED* (Aug. 31, 2020), https://pipeline2.kindermorgan.com/Notices/NoticeDetail.aspx?code=TGP&notc_nbr=376246.

[88] Entergy response to LPSC Staff 4-7 (HSPM).

[89] Entergy 2023 IRP at 63-64.

[90] Entergy response to AAE 10-2 (HSPM). The existing lines in the area and the proposed addition in the transmission alternative use structures, conductors, and clearances with the capability to operate at 230 kV, and thus should have forced outage rates that are most similar to lines operated at that voltage. In fact, these modern structures and conductors may have a lower forced outage rate than the fleetwide average for 230 kV lines of all ages across Entergy Louisiana's system.

<u>III. Entergy has failed to demonstrate BPS is economic or needed to meet a system-wide reliability need</u>

Q. Has Entergy demonstrated that the BPS microgrid is needed for local reliability and resilience?

A. No. As explained in the previous section, during a disturbance the BPS microgrid fails to maintain electric service to customers, who must undergo a power restoration process of unknown duration. Moreover, as noted in Section I, many critical customers like Port Fourchon and LOOP that already have backup generation will see limited value from the BPS microgrid, and Entergy has not assessed how the prevalence of backup generation affects the resilience value of its proposal. Entergy cites resilience for critical customers to justify the price tag of the BPS microgrid, but for many customers this benefit is illusory because the BPS microgrid would not prevent an outage and those customers already have backup. Moreover, a hurricane would likely have taken out other oil and gas pumping stations and shut-in supply from offshore rigs, reducing or eliminating the value of the microgrid for helping to restore many oil and gas customers more quickly.

Entergy's repeated claim that BPS is needed for reliability and resilience due to the loss of the Golden Meadow-Barataria transmission line in Hurricane Zeta in late October 2020[91] is also called into question by the fact that Entergy was already planning BPS well before the loss of that line. In fact, Entergy submitted BPS's interconnection request to MISO in June 2020, and held a pre-application for BPS's air permit in September 2020.[92]

Q. Is BPS needed to meet system-wide load growth?

A. No. Entergy claims BPS will help meet Entergy-wide load growth. When questioned in discovery, Entergy admits that BPS's contribution to meeting system-wide energy needs is trivial, even at the inflated capacity factor Entergy assumes for BPS based on the flawed

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[91] *See, e.g.,* Application at 4 ("As discussed in this Application and in the accompanying testimony, the need for this Project has arisen from the extensive damage to the Golden Meadow-Barataria 115 kV transmission line that occurred during Hurricane Zeta in 2020."); Beauchamp Direct Testimony at 10 ("Initially, the need for the Project arose after extensive damage to the Golden Meadow-Barataria 115 kilovolt . . . transmission line that occurred during Hurricane Zeta in 2020.").
[92] Entergy responses to AAE 1-15 and 1-12 & AAE 1-12 Attachment "LDEQ Pre-App Meeting PPT".

production cost modeling discussed in Section I: "The projected energy output represents a range of approximately 0.26% additional energy coverage on average in the reference gas, reference CO2 scenario to approximately 0.33% on average in the low gas, low CO2 scenario."[93]

Entergy's projections for rapid load growth may also not materialize. There is significant uncertainty about how new types of data centers will drive load growth, in part because some early stage applications for large customer interconnection are speculative applications from customers who have filed multiple interconnection applications with different utilities for the same facility.

Q. Can other resources meet Entergy's load growth more cost-effectively than BPS?

A. Yes. As mentioned in Section I, Entergy can meet load growth through contracts with existing resources, demand response and energy efficiency resources, and new low-cost resources like solar and storage that benefit from federal tax credits.

Using contracts with existing resources includes extending existing PPA contracts. Entergy's IRP notes the expiration of the Oxy-Taft 471 MW PPA in 2028 and the Carville 485 MW PPA in 2032.[94] A significant share of Entergy's apparent energy and capacity need is caused by the expiration of a large PPA contract later this decade. When asked in discovery, Entergy confirmed that this PPA has previously been extended and, when asked "Does Entergy have any reason to believe the generating facility will cease operations when the PPA expires?," Entergy responded "no."[95]

Q. Is BPS more costly than other capacity resources?

A. Yes, other types of gas generators, batteries, and hybrid battery-solar resources are more cost-effective capacity resources than BPS. In response to discovery, Entergy appears to have disclosed its own 2021 analysis that confirms the high cost of RICE units relative to

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[93] Entergy response to AAE 6-5.
[94] Entergy 2023 IRP at 27.
[95] Entergy response to AAE 6-1 (attached as Exhibit MG-7).

alternatives.[96] Entergy's assessment of the installed capital costs of resources on a $/kW basis from what is described as "BP21 technology assessment," which appears to refer to Entergy's Business Plan 2021,[97] are presented in Table 3 below.[98]

Table 3: Entergy assessment of 2028 capital costs of different resources, $/kW (HSPM)

[redacted]

Entergy's application notes the price tag for BPS is "$374.3 million associated with the generation portion of the Project, or roughly $3,318 per kW."[99] Entergy also notes that the total installed cost of BPS, including interconnection, is estimated at $411.3 million,[100] which translates to a total cost of $3,646/kW. This is [[[redacted]]] than the cost of battery storage identified in Entergy's own analysis, and nearly twice EIA's current estimates.[101] Battery storage deployments also receive 30-50% federal investment tax credits, further reducing their cost.

It is also notable that Entergy proceeded with BPS, given its final $/kW cost is markedly higher than the 2021 estimate provided in the table above. In response to discovery, Entergy acknowledges that costs have significantly increased since it analyzed the cost of another power barge project in early 2020, because "significant global events, including supply chain issues and material price increases, significantly altered the marketplace."[102] The competitiveness of the BPS bid is also called into question by the fact that Entergy

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[96] Entergy response to Staff 2-57 Power Barge Rev Req - Ref Gas Ref CO2_HSPM.xlsm, tab "Work Sheet," columns Q-AB (HSPM).
[97] Based on the use of "BP23" to describe Entergy's Business Plan 2023 in Nguyen Direct Testimony at 4.
[98] Entergy response to Staff 2-57 Power Barge Rev Req - Ref Gas Ref CO2_HSPM.xlsm, tab "Work Sheet," columns Q-AB (HSPM).
[99] Application at 9.
[100] As discussed in Section I, Entergy estimates that the total revenue requirement for the BPS project (without accounting for capacity and energy value) is [[[redacted]]].
[101] U.S. Energy Info. Admin., *Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies*, at IV (PDF p. 25/183) (Jan. 2024), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.
[102] Entergy public response to AAE 3-18.

only appears to have received bids from one RICE manufacturer: "two RICE manufacturers were evaluated, but only Wartsila produces RICE engines greater than 10 MW, with Wartsila's 18 MW 18V50SG models (used for the Project) being the largest on the market today."[103] It is likely that RICE generators have experienced greater capital cost increases than other types of generators over the last several years, as Wartsila is based in Europe where costs for key manufacturing inputs like gas and electricity increased dramatically following Russia's invasion of Ukraine.

Q. Do you have questions about Entergy's assumed maintenance costs for BPS?

A. Yes. EIA's estimate of $36.81/kW-year for the fixed O&M costs for a RICE unit[104] is markedly higher than Entergy's estimate of [[[redacted]]].[105] This calls Entergy's assumptions into question, particularly given what are likely unique O&M challenges due to Entergy's proposed barge-based installation. O&M costs for the barge itself, including repainting and dry dock maintenance, may be additional to that,[106] and it is not clear if those unique maintenance costs were fully captured in Entergy's economic analysis.

Q. Entergy has also cited the energy benefits of BPS. Are other new resources more cost-effective sources of energy than BPS?

A. Yes. Combined cycle gas generators, solar, wind, and hybrid resources offer a much lower levelized cost of energy than peaking gas generators. This is confirmed by estimates from the Energy Information Administration[107] and investment firm Lazard.[108] Costs for wind and solar resources are further reduced by generous federal production tax credits, which allow these resources to offer very low PPA prices.

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[103] Direct Testimony of Ryan Daniel Jones, at 9 (Mar. 5, 2024).
[104] U.S. Energy Info. Admin., *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022*, Tbl. 1 (Mar. 2022), https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.
[105] Dickens Direct Testimony, Exhibit GCD-7 HSPM.
[106] In discovery, AAE asked Entergy if the BPS cost estimate includes fixed O&M costs for maintenance of the barge. Although that discovery request (AAE 6-4) was served on August 2, 2024, Entergy has not responded to it.
[107] U.S. Energy Info. Admin., *Levelized Costs of New Generation Resources in the Annual Energy Outlook 2023* (April 2023), https://www.eia.gov/outlooks/aeo/electricity_generation/pdf/AEO2023_LCOE_report.pdf, at 8.
[108] Lazard, *Levelized Cost of Energy +*, at 9 (June 2024), https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf.

Levelized cost of energy is an important metric because data centers and industrial facilities increase Entergy's energy (MWh) needs relatively more than its capacity (MW) needs as these customers typically operate around the clock with an extremely high load factor. Notably, BPS was not mentioned in Entergy's May 2023 IRP,[109] even though development of BPS was well underway at that point. As noted earlier, the IRP uses economic modeling to identify the lowest-cost mix of resources to meet Entergy's capacity and energy needs, and no RICE units or other peaking gas generators were selected in any of the scenarios in that analysis. Instead, renewables, storage, demand response, and energy efficiency accounted for the vast majority of resource additions in all scenarios, with modest additions of combined cycle gas generation in some scenarios.[110]

IV. Entergy failed to evaluate other transmission solutions that may be superior to its proposed transmission alternative

Q. What transmission alternatives did Entergy evaluate?

A. Entergy only economically compared BPS and the transmission alternative that includes rebuilding the Golden Meadow-Barataria transmission line and the conversion of that line and other local lines to 230 kV operation. When asked in discovery, Entergy indicates it did not consider other transmission alternatives. As explained in Section I above, Entergy should have compared BPS against the cost of rebuilding Golden Meadow-Barataria without the unnecessary conversion of that and other lines to 230 kV operation. As I documented above, the transmission solution is much more cost-effective than BPS.

Entergy may have also missed another cost-effective and reliable transmission alternative by failing to consider mounting two circuits on new transmission structures along the existing Valentine-Clovelly-Golden Meadow path. Entergy appears to have ruled out evaluation of that solution, claiming that

> the transmission structures and the Rights of Way associated with the existing transmission system from Clovelly to Fourchon, and the very limited land availability in this region for any additional Right of Way, do

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[109] *See generally* Entergy 2023 IRP.
[110] *Id.* at 88-91.

> not allow for a second circuit on the existing structures or a second transmission line to be constructed along the Clovelly – Fourchon transmission path. Therefore, the best "wires" solution considered for this region was the restoration of the Golden Meadow-Barataria line, as noted in the response to Q8 of Datta's Testimony.[111]

However, Entergy's answer ignores the ability to rebuild the transmission structures and string two circuits on those new structures, which is widely used as a cost-effective and efficient way to achieve greater reliability and transfer capacity on existing transmission right-of-way.

Q. What would this upgrade entail?

A. Entergy could rebuild the structures and add a second circuit along all or part of the Valentine-Clovelly-Golden Meadow line, likely a circuit that would be operated at 115 kV, but if needed it could have the capability to be upgraded to 230 kV operation. Entergy confirms[112] that adding a second circuit on the same structures would meet the requirements of NERC's TPL-001-5 Standard, which allows "non-consequential load loss" or "interruption of firm transmission service" to occur following contingency events that include the loss of "Any two adjacent (vertically or horizontally) circuits on common structure."[113] In other words, NERC standards assign comparable reliability value to two circuits on a single structure relative to two circuits on different structures, as loss of two circuits on a common structure is an extremely rare occurrence. As a result, this solution would likely address Entergy's reliability needs just as well as rebuilding Golden Meadow-Barataria. The additional capacity provided by the second circuit also meets local load growth and other reliability needs as well as rebuilding Golden Meadow-Barataria.

MISO's transmission cost estimation guide indicates that in Louisiana, new double-circuit 115-kV transmission costs around $3.1 million per mile, while double-circuit 230 kV costs

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[111] Entergy response to AAE 6-7 (attached as Exhibit MG-3).
[112] Entergy response at AAE 7-2 (attached as Exhibit MG-8).
[113] NERC, *TPL-001-5, Transmission System Planning Performance Requirements*, Tbl. 1 P7, at 24, https://nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf (last visited Sept. 6, 2024).

around $4 million per mile.[114] Valentine-Clovelly is 14 miles and Clovelly-Golden Meadow is 7 miles, for a total of 21 miles. This indicates an estimated cost of $65 million for 115 kV and $84 million for 230 kV. Some cost savings could likely be realized by re-using the existing conductor for one of the circuits, as that conductor was recently installed and is capable of 230-kV operation.

Because the existing transmission line is the only path serving local load, the line would likely have to be rebuilt while it is energized. Many construction contractors offer this capability,[115] and it has been widely used for applications like this.[116] It typically involves use of a truck-mounted arm that holds the existing energized conductors while the structure is replaced, but could alternatively involve construction of temporary "shoo-fly" lines. There is a cost premium for energized work, but the Commission should require Entergy to obtain competitive bids to evaluate the cost of this solution relative to Entergy's proposed BPS and transmission alternative.

Q. Is there precedent for Entergy proposing energized work along this route?

A. Yes. When asked about Entergy's recent rebuilding of the Golden Meadow-Clovelly line, Entergy acknowledges that:

> The original plan for this rebuild project was to perform the construction while the line was still energized (a.k.a. "hot work"), utilizing very specialized and very costly methods, safety procedures, and equipment, in order to avoid impacting customers served from Golden Meadow Substation. However, this line was severely damaged during Hurricane Ida,

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[114] MISO, *Transmission Cost Estimation Guide For MTEP24*, at 39 (May 2024), https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf.

[115] For example, see Quanta Energized Servs., *About Quanta Energized Services*, https://www.quantaenergized.com/about/ (last visited Sept. 6, 2024); H&M Henkel Services, *Energized Services* (May 2021), https://www.henkels.com/sites/henkels/files/2021-05/HM_Energized%20Services_2021-HR-FNL.pdf.

[116] For example, see Riggs Distler, *Cranbrook 60kV Energized Rebuild and Reconductor*, https://riggsdistler.com/projects/delivering-turnkey-power-construction-solutions-in-the-ocean-state/ (last visited Sept. 6, 2024); Quanta Energized Servs, *Intercession City–Dundee 230-kV Rebuild*, https://www.quantaenergized.com/project/574-2-2-2/ (last visited Sept. 6, 2024); Alltech, *Cranbrook 60kV Energized Rebuild and Reconductor*, https://allteck.com/projects/cranbrook-60kv-energized-rebuild-and-reconductor/ (last visited Sept. 6, 2024).

> resulting in loss of electrical service to those customers until the line could be rebuilt. Subsequently, the construction plan was changed to rebuild the line utilizing conventional design and methods as quickly as possible.[117]

Entergy further confirms that this plan for energized work was developed with the current transmission network configuration following the loss of Golden Meadow-Barataria.[118] As a result, Entergy could pursue a similar solution for rebuilding these segments to add a second circuit.

Conclusion

Q. Please summarize your findings and recommendations.

A. First, I presented a revised economic analysis that shows the transmission alternative is far less costly than the BPS, after correcting errors in Entergy's analysis that overstate the value of the BPS as well as the cost of the transmission alternative. Second, I demonstrated that a transmission alternative is superior to BPS for electric reliability and resilience. Third, I reviewed data from Entergy and others showing that BPS is much more costly than other sources of energy and capacity. Fourth, I presented another transmission alternative that likely also offers lower cost than the BPS.

Based on those findings, I respectfully recommend that the Commission reject Entergy's Application for approval to construct the BPS. Instead, the Commission should direct Entergy to refine cost estimates for the transmission alternatives and correct the errors in its BPS economic analysis. Once the Commission determines that one of the transmission alternatives offers a lower cost than BPS, the Commission should direct Entergy to proceed with filing for a certificate to construct that transmission alternative.

Q. Does this complete your testimony at this time?

A. Yes.

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[117] Entergy response to AAE 8-1.
[118] *Id.*

Exhibit MG-1
Michael Goggin's-CV

Michael Goggin

Education:

Harvard University class of 2004, B.A. *cum laude* in Social Studies

- Wrote thesis "Is it Time for a Change? Science, Policy, and Climate Change"

Experience:

Grid Strategies Vice President February 2018-present

- Serve as an expert consultant on electricity transmission, grid integration, reliability, market, and public policy issues for environmental and clean energy industry clients
- Have testified before FERC and in dozens of state regulatory commission cases
- Actively engaged in NERC Standards development processes related to renewable and storage resources

AWEA Senior Director of Research, other titles February 2008-February 2018

- Led team responsible for all American Wind Energy Association analysis
- Served as primary technical and economic expert on market design, transmission, grid integration, carbon policy, and other topics
- Authored regulatory filings at state (IRP and transmission siting cases), regional (RTO transmission and market design), and federal levels (FERC transmission, interconnection standard, grid integration, and market design cases; EPA carbon policy)
- Directed economic and power sector modeling to inform AWEA's policy strategy and support advocacy positions
- Communicated with the press and policy makers about wind energy
- Other titles included Electric Industry Analyst, Senior Analyst, Manager of Transmission Policy, Director of Research

Sentech, Inc. Research Analyst October 2005-February 2008

- Conducted economic analyses of solar, wind, geothermal, hydrogen, and energy storage technologies for U.S. Department of Energy officials
- Provided analytical support for DOE's renewable energy R&D funding decisions

Union of Concerned Scientists Clean Energy Intern May 2005-October 2005

- Worked with the legislative and field staff to promote the inclusion of pro-renewable energy measures in the Energy Policy Act of 2005

State Public Interest Research Groups Policy Analyst August 2004-May 2005

- Analyzed and advocated for clean energy policies at the state and federal level

Publications available at https://gridstrategiesllc.com/reports/

Exhibit MG-2
Entergy Response to Staff 2-51

(REDACTED DUE TO HIGHLY SENSITIVE PROTECTED MATERIALS PURSUANT TO CONFIDENTIALITY AGREEMENT IN LPSC DOCKET NO. U-37131)

Exhibit MG-3
Entergy Response to AAE 6-7

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37131

Response of: Entergy Louisiana, LLC
to the Sixth Set of Data Requests
of Requesting Party: Alliance for Affordable
Energy

Question No.: AAE 6-7 Part No.: Addendum:

Question:

Please explain why Entergy did not evaluate each of the following potential alternatives to BPS:

a. Battery storage, either grid-forming or grid-following

b. Battery storage and solar generation

c. Demand response

d. Transmission upgrades other than rebuilding the Golden Meadow – Barataria line

e. Some combination of a, b, c, and d

Response:

The Company objects to this request as it is based upon an improper premise, misconstrues, or otherwise misstates testimony filed in this docket. Subject to and without waiving these objections, the Company responds as follows:

As explained in Q10 of company witness Datta's Direct testimony, the company did consider alternatives to the BPS that would deliver the objective of a second source of power to the targeted region while increasing the resilience of the electric system. As explained in the Testimony, space constraints in this region do not allow for a solar resource to be constructed. Since the objective of the various alternatives considered was to be able to restore power for an extended period of time following a transmission outage resulting from a significant weather event, an energy storage device is not suitable to for such an application given the finite energy capability of such battery systems that limit the time duration for which such a system may be able to sustain the restoration of customer load after the transmission outage. In addition, as noted in the Testimony, the induction motor load present in this region require any power solution to be able to support a high starting current requirement which is difficult to achieve with inverter-based resources, such as battery or photovoltaic systems. While demand response is useful as a peak-shaving resource, it does not assist in restoring power after an outage and was, therefore, not considered as an alternative to the BPS. Finally, the transmission structures and the Rights of Way associated with the existing transmission system from Clovelly to Fourchon, and the very limited land availability in this region for any additional Right of Way, do not allow for a second circuit on the existing structures or a second transmission line to be constructed along the Clovelly – Fourchon transmission path. Therefore, the best “wires” solution considered for this region was the restoration of the Golden Meadow – Barataria line, as noted in the response to Q8 of Datta’s Testimony.

Exhibit MG-4
Entergy Responses to
Staff 2-6 and 2-7

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37131

Response of: Entergy Louisiana, LLC
to the Second Set of Data Requests
of Requesting Party: Louisiana Public Service
Commission Staff

Question No.: STAFF 2-6 Part No.: Addendum:

Question:

Do critical customers such as LOOP have their own backup generation capable of operating if grid power is not available?

Response:

The Company objects to this request as vague and ambiguous, overly broad and unduly burdensome. Subject to and without waiving these objections, the Company responds as follows:

Unless a customer has contracted with the Company for backup generation, such as through the Power Through program, the Company cannot definitively state whether a certain customer, regardless of critical designation, has or does not have backup generation and, if the customer does have back up generation, whether such generation would be sufficient for the customer to continue operations in the event power from the grid was not available.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37131

Response of: Entergy Louisiana, LLC
to the Second Set of Data Requests
of Requesting Party: Louisiana Public Service
Commission Staff

Question No.: STAFF 2-7 Part No.: Addendum:

Question:

Did the Company analyze providing backup generation to customers downstream of Clovelly as an alternative to the transmission-only or Power Barge solutions? If so, explain the results of this analysis. If not, why not?

Response:

Providing backup generation for each customer downstream of Clovelly individually was not considered as a viable alternative to the non-wires solution described in Company witness Datta's testimony. Installing a back-up generator at each customer's electric service entry point with an automatic transfer switch, providing fuel for the back-up generators for each customer, maintaining these generators at each customer's facility, and ensuring fuel supply for each customer during an extended outage would be a very significant undertaking. A back-up generator installed conventionally at each customer's facility would also not provide the energy and capacity market benefits that can be realized by the operation of the BPS. That is because backup generators cannot normally be controlled in a manner that allows them to be dispatched in the energy market. Moreover, back-up generators, especially those that are normally used on residential and commercial facilities are less efficient than the BPS is designed to be. Finally, because back-up generators are not conventionally able to be controlled that allows them to be offered as a capacity resource into the Planning Resource Auction, backup generators installed for each customer downstream of Clovelly will also not provide the capacity market benefits that will be realized in the future with the BPS. The BPS will also be a grid resource that is capable of quick starts and able to ramp up and down rapidly, this providing flexible capacity to the system that can be used to compensate the intermittent renewable resource, thus allowing for increased renewable energy penetration. Such a benefit cannot be realized with backup generators at each customer's facility because the inability to control such smaller backup generators in a manner that allows for them to respond to grid conditions. For these reasons, a grid resource, such as the BPS, was considered for the non-wire alternative options, rather than back-up generators for each customer in the region.

The Company's Power Through program would not be a viable option to provide backup generation for each customer in the region due to various constraints in the program as approved by the Commission.

Exhibit MG-5
Entergy Response to AAE 7-1

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37131

Response of: Entergy Louisiana, LLC
to the Seventh Set of Data Requests
of Requesting Party: Alliance for Affordable
Energy

Question No.: AAE 7-1 Part No.: Addendum:

Question:

Please see Witness Datta's statement at page 19 that "In this manner, this microgrid controller will enable expedient recognition of an interruption of power to the region, a quick transition to the microgrid island, and rapid restoration of power inside the region, thus providing a resilient power source, as discussed by Company witness Sean Meredith."

a. Please confirm that the proposed microgrid functioning as intended will involve the load served by the microgrid being interrupted and then restored. If that is not accurate, please explain why.

b. Approximately how long does Entergy expect load restoration in the microgrid to typically take? If Entergy expects microgrid loads to be restored sequentially, please describe the rate of that restoration. If Entergy has not analyzed or documented the expected duration or rate of load restoration, please explain why that has not been analyzed or documented.

c. If a significant share of loads is restored simultaneously, would BPS be able to handle that?

d. Does Entergy have a plan for coordinating the load restoration with large customers so that BPS can follow the load changes?

e. Does Entergy have a plan for coordinating the reconnection of distribution circuits within the microgrid.

f. Please provide any restoration plan for the microgrid. If one does not exist, please explain why.

Question No.: AAE 7-1

Response:

The Company objects to this request to the extent that it seeks information, documents or analyses that have not been performed or do not exist. Subject to and without waiving these objections, the Company responds as follows:

a. Yes, that is correct.

b. While the Company has developed the high-level steps that have to be implemented for the formation of the microgrid and studied these steps for effectiveness in the analyses provided in response to AAE 6-12, the Company has not yet developed detailed operational procedures needed to incorporate the microgrid controller actions with the Company's Transmission and Distribution control center procedures in collaboration with operations at the large industrial customers in the microgrid island. Therefore, the Company does not have an estimate of the range of load restoration timelines that are expected for the microgrid. Such detailed operational procedures are expected to be developed and prior to the Commercial Operations Date of the BPS.

c. The Company's time-domain analyses (referred to in subpart (b) above) included determining the voltage and frequency within the microgrid during the simulated microgrid implementation steps to make sure the electrical system remained reliable, stable and within acceptable limits. These studies identified the sequence of restoration of load at various feeders within the microgrid island during the microgrid island operation and the number of generators that need to be online in the island to maintain acceptable frequency and voltage. The detailed operational procedure referred to in subpart (b) above will ensure that the BPS will be able to accommodate the amount of load being restored at every step during the restoration of power during the formation of the microgrid island.

d. Yes, the Company will work with the major industrial loads in the microgrid to ensure that the restoration steps involved in the formation of the microgrid island work in conjunction with the restoration of industrial operations at customer facilities, especially those that involve customer-operated substation equipment. Such detailed operational procedures are expected to be developed and finalized prior to the Commercial Operations Date of the BPS.

e. Yes, the Company's time-domain studies (referred to in subpart (b) above) included high-level restoration steps that analyzed the optimal sequence of the energization of the distribution feeders at each substation such that the BPS is able to maintain frequency and voltage within acceptable limits within the microgrid island. A detailed operational procedure ensuring proper coordination between the actions of the microgrid controller, the Transmission Control Center actions and those of the Distribution

Operations Center is expected to be developed and finalized prior to the Commercial Operations Date of the BPS.

f. An operational procedure detailing every step during the restoration of power during the formation of the microgrid island will be developed and finalized prior to the Commercial Operations Date of the BPS.

Exhibit MG-6
Entergy
Frequently Asked Questions About New Orleans Power Station

entergy
(/brightfuturenola/)

Frequently Asked Questions About New Orleans Power Station

Did New Orleans Power Station work during Hurricane Ida?

NOPS operated as expected and did exactly what it was designed to do both during and following Hurricane Ida.

Hurricane Ida, the fifth strongest hurricane ever to hit the United States, devastated the local electric grid, which is called a distribution system, and damaged portions of the surrounding transmission system, which carries electricity over longer distances. When a storm causes widespread damage to the grid, all power plants are designed to shut down automatically. Power plants that continue operating when there are no lines connecting to customers risk being damaged or destroyed if they do not shut down. New Orleans Power Station shut down as designed when Ida struck the region.

When did NOPS restart following the hurricane?

Within 48 hours after Hurricane Ida left the region, NOPS had been restarted and connected to the local electric grid.

Why didn't NOPS start up immediately after the hurricane ended?

NOPS was able to start up and begin generating power nearly immediately after the hurricane left the region. However, engineers need to ensure that there is a connection between the power plant and customers via local power lines. Following Ida, there was devastation to electric distribution facilities. For example, the number of poles damaged or destroyed from Ida is more than from Hurricanes Katrina, Ike, Delta and Zeta combined.

If damage to the grid is too great, NOPS could have been damaged or destroyed if it was started up prematurely.

What does "blackstart" mean? Can NOPS use blackstart, and would that have gotten electricity flowing sooner?

While NOPS is capable of blackstart operation, meaning to come online with no grid power to support it, it was not required to play that role following the storm. A transmission line from Slidell was largely undamaged and thus available to be used in combination with power generated by NOPS to restore first lights to New Orleans less than 48 hours after Ida left the region.

It is more reliable and safer to operate a power plant in conjunction with a transmission line in service, rather than in an “island” configuration. There was no difference in time between using blackstart and operating in island mode versus waiting for the line from Slidell to be reconnected. Rather, the reason it took 48 hours to bring NOPS back online is because we had to ensure that the distribution lines connecting NOPS to customers were secured and that customers could take power safely. Starting NOPS without ensuring the ability to deliver its power would have been unsafe and could have damaged or destroyed the plant.

If that transmission line from Slidell had been destroyed in the storm, NOPS would have enabled the New Orleans area to be restored -- in an island configuration – during the time required to repair or replace the transmission line.

Who received power first from NOPS after it was restarted following the hurricane?

NOPS is located in the New Orleans East area of the city. Within 48 hours after Hurricane Ida left the region, NOPS was generating electricity for customers in certain New Orleans East neighborhoods, as well as some critical facilities like hospitals and first responder facilities.

Can NOPS supply enough electricity for the entire city?

No. NOPS can generate a maximum of 128 megawatts of electricity, enough to power approximately 80,000 residences, give or take depending upon actual usage, in the city. It was never intended to power the entire city, although the original plan called for NOPS to generate over 200 megawatts.

The city and surrounding areas, such as Jefferson, St. Tammany, St. Bernard, St. John, St. James and other parishes, have a diverse array of power supplies, including electricity generated by the use of natural gas, nuclear and solar power, and some electricity is delivered to the region over many miles by high voltage transmission lines.

We power life.[SM]

Exhibit MG-7
Entergy Response to AAE 6-1

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37131

Response of: Entergy Louisiana, LLC
to the Sixth Set of Data Requests
of Requesting Party: Alliance for Affordable Energy

Question No.: AAE 6-1 Part No.: Addendum:

Question:

Please see Entergy's response to Staff 1-5, row 57, showing a PPA that expires.

a. Has this PPA previously been extended?

b. If so, please document when it had been slated to expire and when it was extended.

c. Has Entergy had any discussions with the plant owner regarding extending the PPA? If so, please describe those discussions.

d. Does Entergy have any reason to believe the generating facility will cease operations when the PPA expires? If so, please describe those reasons.

Response:

a. Yes

b. The term of the prior Oxy PPA expired on May 30, 2018, and the term of the current Oxy PPA began on June 1, 2018.

c. No

d. No

Exhibit MG-8
Entergy Response at AAE 7-2

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37131

Response of: Entergy Louisiana, LLC
to the Seventh Set of Data Requests
of Requesting Party: Alliance for Affordable
Energy

Question No.: AAE 7-2 Part No.: Addendum:

Question:

Please see the statement on page 26 of Witness Beauchamp's testimony that "a new Barataria – Golden Meadow line would need to be constructed to 230 kV capability to provide two transmission sources to the Golden Meadow substation. ELL would need to perform these additional upgrades to comply with NERC reliability standards."

a. Can adding a second circuit in the voltage range of 115 kV to 230 kV to all or part of Valentine-Clovelly-Golden Meadow, potentially in conjunction with other upgrades along that path or south of Golden Meadow, provide the second transmission source that is needed to comply with NERC reliability standards without rebuilding the Barataria-Golden Meadow line? If so, please explain which parts of Valentine- Clovelly-Golden Meadow would require a second circuit to comply with NERC reliability standards without rebuilding the Barataria-Golden Meadow line. If not, please explain why.

b. If the answer to subpart a is that other upgrades would be needed along the Valentine- Clovelly-Golden Meadow path or south of Golden Meadow would be needed to comply with NERC reliability standards, please describe or document those upgrades and explain why each is needed.

c. Please confirm that it is not a violation of NERC TPL-001-5 for "non-consequential load loss" or "interruption of firm transmission service" to occur following contingency events that include the loss of "Any two adjacent (vertically or horizontally) circuits on common structure." (please refer to Table 1, P7 on page 24 at https://nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf) If you believe that is a violation of TPL-001-5, please explain why.

d. Please provide any discussions, documents, or analysis in Entergy's possession related to adding a second circuit to all or part of the Valentine-Clovelly-Golden Meadow path. If Entergy has not discussed or analyzed adding a second circuit to all or part of the Valentine-Clovelly-Golden Meadow path, please explain why.

e. Why was adding a second circuit for Valentine-Clovelly-Golden Meadow not included in Witness Datta's analysis of potential transmission solutions?

Response:

Please see the Company's response to AAE 7-3. Additionally, non-consequential load loss or interruption of firm transmission service is allowed for P7 contingencies in accordance with NERC Reliability Standard TPL-001-5.

CERTIFICATE OF SERVICE

I, Trish Bosch, hereby certify that I have this 18th day of September, 2024, served copies of the Redacted Version of the Direct Testimony and Exhibits of Michael Goggin, on Behalf of the Alliance for Affordable Energy, on all other known parties on the Official Service List for Docket No. U-37131 via electronic mail, addressed as follows.

Trish Bosch
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