SOAH DOCKET NO. 473-22-1074
PUC DOCKET NO. 52487

APPLICATION OF ENTERGY TEXAS, INC. TO AMEND ITS CERTIFICATE OF CONVENIENCE AND NECESSITY TO CONSTRUCT ORANGE COUNTY ADVANCED POWER STATION	§ § § § §	**PUBLIC UTLITY COMMISSION OF TEXAS**

REDACTED VERSION

DIRECT TESTIMONY OF

DEVI GLICK

ON BEHALF OF SIERRA CLUB

March 18, 2022

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, utility resource planning practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. I have submitted expert testimony on unit-commitment practices, plant economics, utility resource needs, and solar valuation before state utility regulators in Texas, Arizona, Arkansas, Connecticut, Florida, Indiana, Michigan, Nevada, New Mexico, North Carolina, Ohio, South Carolina, Virginia, and

Wisconsin. In the course of my work, I develop in-house electricity system models and perform analysis using industry-standard electricity system models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than seven years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Public Utility Commission of Texas ("Commission" or "PUCT")?

A Yes. I submitted testimony in Texas PUC Docket No. 49831, Application of Southwestern Public Service Company for Authority to Change Rates, Docket No. 50997, Application of Southwestern Electric Power Company for Authority to Reconcile Fuel Costs for the Period May 1, 2017–December 31, 2019, and in Docket No. 51415, Application of Southwestern Electric Power Company for Authority to Reconcile Rates.

Q What is the purpose of your testimony in this proceeding?

A In this proceeding, I evaluate the robustness of Entergy Texas, Inc.'s ("ETI" or "Company") modeling and procurement process that resulted in the Company's selection of the Orange County Advanced Power Station ("OCAPS" or "Orange

County Gas Plant") for which it seeks approval in this application. I also evaluate ETI's claims about the economic and environmental benefits that the proposed plant will provide. Finally, I provide my recommendations for how ETI should proceed in meeting its future system needs.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I detail my concerns with the Company's justification for spending $1.19 billion to build a 1,215 megawatt (MW) gas plant, including an unreasonably high industrial load forecast and extremely low incremental demand-side investment. I also explain why ETI's position that it cannot rely on in-region capacity and energy to meet long-term resource needs is faulty and will result in unnecessary costs for ratepayers.

In Section 4, I describe my concerns with the extremely narrow and limited "portfolio analysis" process ETI used to select the combined cycle gas turbine ("CCGT") technology. I explain why optimized capacity expansion modeling informed by real-world market prices is the industry standard for evaluating system need. And I also discuss my concerns with the request for proposal (RFP) process the Company's carried out in the early months of the pandemic. Specifically, I discuss how the markedly narrow procurement process inhibited competition and ultimately garnered zero competitive bids.

In Section 5, I discuss my concerns with ETI's economic analysis, and the Company's use of a faulty baseline to manufacture the appearance of a $1.85 billion savings to make the OCAPS project look like a good deal for ratepayers. I summarize my own optimized capacity expansion modeling, which shows that the region can more cost-effectively meet near-term resource need through solar PV

and battery storage, and not a new gas plant. Finally, I detail my concerns with the Company's claims that OCAPS will be clean based on its ability to co-fire on hydrogen and its low heat rate. Specifically, I explain how the plant's emissions rate will actually be worse using grey hydrogen, as the Company indicated it plans to do at least initially, and I evaluate the lifetime impact of locking in a high capacity factor gas plant for another three decades.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of ETI's witnesses. I also rely on public information from other PUCT proceedings and other publicly available documents.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. ETI did not robustly consider supply- or demand-side alternatives to the Orange County Gas Plant in its modeling of resources to meet system needs after Sabine Units 1, 3, and 4 are taken offline.
2. ETI's load forecast that supports the need for a 1,215 MW plant relies on the assumption that a large quantity of highly uncertain industrial load will materialize in the future and assumes minimal deployment of incremental energy efficiency and other demand-side management measures.
3. ETI's RFP was extremely limited and narrow in scope, seeking only bids for a large, single, fossil plant. It resulted in no third-party bids and therefore did not truly test the market for competitive alternatives to ETI's self-built CCGT.

4. ETI's decision to spend an extra $60 million to allow the plant to co-fire on hydrogen is not supported by economic analysis and is likely to produce more emissions than if the plant operated on gas alone.

5. ETI's calculation of $1.85 billion in lifetime savings from building the Orange County Gas Plant is premised on a faulty baseline, comparing the cost to build and maintain a large energy resource to the cost to build and maintain peaking capacity resources that are also capable of co-firing on hydrogen.

6. Synapse's economically optimized modeling indicates that solar PV and battery storage can likely meet capacity and energy needs in MISO Local Resource Zone (LRZ) 9 at a lower cost than gas. Further, the model economically selected no new baseload gas plants before 2031, suggesting ETI customers do not currently need the proposed gas plant.

7. ETI claims that the gas plant will be "clean" because it has a better heat and emission rate than the 50-plus-year-old Sabine units it is replacing. But in reality, bringing the plant online is locking in a huge quantity of lifetime emissions, which increases risks faced by ETI and its customers, that could be avoided with alternative supply- and demand-side resources.

8. The addition of the Orange County Gas Plant will further skew ETI's resource portfolio in the direction of heavy reliance on gas. This limited diversity is bad for reliability and resiliency.

Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

1. The Commission should deny ETI's application to amend its certification of convenience and necessity (CCN) to construct the OCAPS.

2. The Commission should require ETI to issue an all-source RFP for supply- and demand-side resources that can provide, individually or in combination, the services that ETI will need to maintain a reliable electricity system.

3. The Commission should require ETI to perform optimized capacity expansion modeling to evaluate the results of the all-source RFP and determine the most economic resource mix to meet its near-term needs.

4. The Commission should require ETI to model a sensitivity to evaluate the cost to ratepayers if ETI builds the plant and then the projected industrial growth does not materialize.

3. ETI IS PROPOSING TO SPEND $1.19 BILLION TO BUILD A NEW 1,215 MW COMBINED CYCLE GAS TURBINE PLANT IN EAST TEXAS TO MEET HIGHLY UNCERTAIN FUTURE LOAD GROWTH.

i. Background on the plant

Q What is ETI proposing in this docket?

A ETI is seeking approval for a CCN to construct a new 1,215 MW 2x1 CCGT facility in Bridge City, Texas. The project is expected to cost $1.19 billion and to enter into service in the first half of 2026.[1] ETI is proposing to build the new plant at ETI's existing Sabine facility in Orange County. This site has existing transmission infrastructure and, ETI claims, access to hydrogen infrastructure and fuel storage capabilities.[2] ETI plans to transfer the existing transmission rights it has at the Sabine Units 1, 3, and 4 to OCAPS, and request an additional 66.7 MW of generation through the MISO generator interconnection process.[3] Transmission upgrades account for approximately $85.9 million out of the total $1.19 billion

[1] Direct Testimony of Sallie T. Rainer, pages 8-9.
[2] Application of ETI to amend its CCN to construct OCAPS, pages 2-3.
[3] Direct Testimony of Daniel Kline, page 17.

project cost.[4] The project cost includes a $65 million investment in plant infrastructure that will enable the plant to co-fire up to 30 percent hydrogen.[5]

Q How did ETI select the OCAPS project?

A In direct testimony, the Company described a multi-step evaluation and procurement process that included limited analysis and only considered resource portfolios consisting of large new gas plants.

Specifically, ETI first completed a decommissioning study on the Sabine Units 1, 3, and 4 to determine whether and when the units should be retired. The Company then created a load forecast (which assumed a high level of industrial load growth) and performed a "portfolio analysis" where it evaluated a very limited set of alternative resource portfolios to replace the retiring Sabine units and meet projected load growth. This "portfolio analysis" resulted in the elimination of all resources that the Company considered uneconomic, which was everything except a 2x1 CCGT plant. ETI presented the results of this portfolio analysis to the Operating Committee and received approval to move forward with the CCGT RFP on October 16, 2019.[6] This means the Company's consideration of alternatives ended nearly two and a half years ago, or nearly 7 years before it plans to bring the replacement resource online.

Then, on April 28, 2020, a month and a half into the pandemic, ETI issued an RFP for a large (1,000–1,200 MW) CCGT located within the eastern load pocket.

[4] Direct Testimony of Daniel Kline, page 27.
[5] Direct Testimony of Sallie T. Rainer, page 8.
[6] Exhibit ABW-6 (Public), pages 1-2.

This RFP process resulted in only one response (submitted in August 2020)– ETI's self-build option.[7] As I will discuss later, this was unsurprising given the time of its release early in the pandemic, the extremely limited scope of the RFP, and the outcome of ETI's prior CCGT RFP that resulted in the selection of the ETI self-built Montgomery County Power Station.

ETI then performed a second set of economic analyses to calculate the "benefits" of the project compared to a faulty baseline of building new CTs and purchasing energy from the market. The Company shared these results with the ETI Operating Committee on September 9, 2021.[8]

ii. ETI is justifying the need for the plant based on meeting hypothetical future industrial load.

Q How does ETI justify the need for a new 1,215 MW gas plant?

A ETI plans to deactivate three units at the Sabine Power Station that account for roughly 1,100 MW[9] of capacity: Sabine 1 in 2023, Sabine 3 in 2026, and Sabine 4 in 2026 or whenever OCAPS comes online.[10]

ETI also projects that its MISO Coincident Peak load will be 348 MW or 10.3 percent higher by planning year 6/1/2026–5/31/2027 than it was in 2021.[11] The Company expects a capacity shortfall of 1,073 MW in 2026, increasing to 1.4 GW

[7] Exhibit PDN-1; Exhibit PDN-2 (Public), page 3.
[8] Exhibit PDN-3 (Public), page 1.
[9] Direct Testimony of Sallie T. Rainer, page 4.
[10] Exhibit ABW-5 (Public), page 8.
[11] Weaver WP_ABW Testimony_HSPM_Errata No. 2.

in 2031,[12] and an energy shortfall of almost 9.2 terawatt hours (TWh) in 2026. This accounts for 40 percent of ETI's projected energy needs at this time.[13] The Company attributes the majority of its load growth projections to the industrial sector.[14]

Q How do these projections compare with ETI's historically observed load growth?

A ETI is projecting substantially higher levels of load growth than the Company has historically experienced. Specifically, the Company's peak load grew by only 4.6 percent, or 1.1 percent per year, during the prior five years between 2016 and 2020. ETI projects its coincident peak load will grow by around 2 percent per year for a total of 10.3 percent between the years 2021–2026. This is more than double the level of load growth observed historically. [redacted][15]

[12] Direct Testimony of Abigail B. Weaver, page 12.
[13] *Id*.
[14] Application of ETI to amend its CCN to construct OCAPS, page 2.
[15] Weaver WP_ABW Testimony HSPM Errata No. 2.

Figure 1: CONFIDENTIAL ETI's year-over-year assumptions for MISO Coincident Peak growth (percent)

Source: Weaver WP_ABW Testimony HSPM Errata No. 2.

Q Explain ETI's industrial sector load forecast and its justification for such aggressive assumptions.

A At the time of its forecast development, ETI included 556 MW of active pipeline projects in its Business Plan 2021.[16] Of these new industrial projects, [redacted] would be located within the load pocket.[17] ETI developed this forecast based on its assessment of the probability that each project in its economic development pipeline will come online.[18] That means that the industrial forecast is composed entirely of projects that might or might not be constructed and bring new electricity customers.

[16] Direct Testimony of Ryan Magee, page 9.
[17] ETI Response to TIEC Request 11-7, HSPM Attachment 2.
[18] Direct Testimony of Ryan Magee, page 7.

The Company justified this decision by saying:

> Given the long lead times to site, permit, and construct new generation, ETI cannot wait until new or expanding industrial loads are already in place to make strategic supply decisions. Well in advance of making a decision to locate or expand, customer[s] must be assured that ETI is prepared to meet their anticipated electrical demand needs.[19]

Q What reasons do you have to believe that ETI's industrial load growth might not materialize as projected?

With the economy recovering from the global pandemic, there have been supply chain and worker shortages across the entire economy. This not only impacts ETI's construction and operational costs; it also has cascading impacts across the industry. This is not to say that a recovery is not possible; but there is inherent risk in planning around the assumption that this trend will reverse in the near future, and this will lead to dramatic near-term growth. If a prospective new industrial customer is experiencing supply chain challenges or a current shortage of workers, this could have a very real impact on the cost to construct and operate a new facility. That impact could affect the Company's decision to move forward with a new or expansion project.

One local area newspaper discussed the likely shortage of workers in the Port Arthur area this year stating that the demand for workers will likely outstrip the available work force "which could impact the pace of several giant oil and gas

[19] Direct Testimony of Daniel Kline, page 4.

projects, as well as the local economy's post-pandemic recovery."[20] The article quoted a Chair of the Greater Port Arthur Chamber of Commerce's Contractor Development group who estimated that that there were at least $79 billion in industrial projects planned between Beaumont and Baton Rouge over the next few years. He indicated that these projects were expected to require at least 87,000 contractors, but they only had about 40,000.[21]

This shortage is not a new concern, with existing companies Sempra and Golden Pass LNG working on generating enough workers to handle demands. The article ends by stating "Several key final investment decisions worth billions, like the expansion of Chevron Phillips in Orange and Sempra's Port Arthur LNG, have since been pushed back multiple times since the beginning of the pandemic."[22]

[redacted][23]

Q Has ETI projected similar high industrial load growth in the past?

A ETI does not publish Integrated Resource Plans in Texas, so it is difficult to nail down the Company's historical industrial projections in Texas. But the West of the Atchafalaya Basin ("WOTAB") region spans the states of both Texas and Louisiana, the latter of which is served by ETI's sister utility, Entergy Louisiana

[20] Jacob Dick, "Contracts could see more work than they can manage next year." Beaumont Enterprise, December 26, 2021. Available at https://www.beaumontenterprise.com/business/article/Area-contractors-have-plenty-of-work-obstacles-16686516.php.

[21] *Id.*

[22] *Id*.

[23] ETI Response to TIEC 7-16, Addendum 1, Attachment 1, HSPM Magee Exhibit RMI-Revised (HSPM).

("ELL"). We can look to ELL, which does produce integrated resource plans (IRP) with documented historical industrial load forecasts, to understand how the Company's historical projections for the WOTAB-region oil and gas industry compare with what actually happened. ELL's 2015 IRP shows that in the years leading up to the Covid-19 pandemic the Company was expecting a boom in industrial load growth in the Louisiana section of the WOTAB load pocket that it dubbed an "industrial renaissance." At the time, ELL projected up to 1,600 MW of industrial load growth by 2019 for a total of 11,200 MW, and up to 400 more MW of load growth by 2025 driven primarily by industrial load growth.[24]

The reality in the intervening years has been sobering. Now, in its 2023 IRP, ELL expects to reach only 10,500 MW of peak load by 2040 in its reference forecast.[25] ELL's current reference scenario's load projections are lower than the lowest projection in its 2015 IRP and are on par with the lowest load scenario it modeled in its 2019 IRP.[26] This highlights the importance of not just modeling low-growth scenarios, and but also understanding the impact of planning for and not meeting high-growth projections.

Q Did ETI evaluate any scenario with more reasonable industrial load growth assumptions?

A No. ETI did not evaluate any reference scenarios with more reasonable load growth assumptions, or otherwise evaluate (1) the optimal resource portfolio

[24] Ex. DG-4, Entergy Louisiana, LLC. 2015 Final IRP, page 25 (Aug. 3, 2015).
[25] Ex. DG-5, Entergy Louisiana, LLC. 2023 IRP Data Filing – Updated, page 8 (Feb. 11, 2022).
[26] Ex. DG-4, Entergy Louisiana, LLC. 2015 Final IRP, page 25; Ex. DG-6, Entergy Louisiana, LLC. 2019 IRP Long Term Planning Assumptions, page 8 (May 2019); Ex. DG-5, Entergy Louisiana, LLC. 2023 IRP Data Filing – Updated, page 8 (Feb. 11, 2022).

under a lower load forecast; or (2) the risk to ratepayers if ETI built the plant and the projected industrial load did not materialize as projected.

Q Why are you concerned that ETI did not evaluate a lower load growth scenario?

A ETI indicated that it expects OCAPS to operate at a high capacity factor and sell a significant quantity of energy into the MISO market. ETI further indicated that it expects positive margins from these sales that will offset ETI customer fuel costs due to the expected low cost to operate the plant relative to market prices.[27]

This means that in the scenario where industrial load does not materialize, the Company will just sell the excess generation into the MISO market where it expects to earn positive margins. But that would expose ETI to market price volatility as a supplier. And given the Company's concerns with price volatility in relying on market purchases to meet system needs, it is no more reasonable to rely on market sales to cover the costs of an over-built system. ETI did not test any reference scenarios with lower load growth; it therefore provided no data on the impact on projected market prices and projected revenue of building the plant and then not needing as much energy as projected to serve internal load.

[27] Direct Testimony of Abigail B. Weaver, page 5.

iii. ETI has invested only minimally in energy efficiency and other demand-side management options, and it is projected to continue this trend.

Q How does ETI's current energy efficiency performance measure up against other utilities?

A ETI has historically underinvested in energy efficiency relative to other investor-owned utilities in Texas, its affiliated Entergy utilities in other states, and investor-owned utilities nationwide. This is concerning because energy efficiency is, and will continue to be, the lowest cost energy resource; it should therefore be part of any low-cost resource portfolio. ETI should be ramping up investment in energy efficiency and demand-side management as a first step in addressing any future resource needs.

In 2020, ETI's energy efficiency savings as a percent of retail sales, as reported to the U.S. Energy Information Administration (EIA), was only 0.24 percent and its five years average from 2016–2020 was 0.23 percent.[28] This is extremely low compared to the reported national average energy savings in 2020 of 0.91 percent of retail sales among investor-owned utilities in the United States. Even among Texas utilities, who admittedly trail far behind their peers across the United States, the average energy efficiency performance is roughly double (0.42 percent) what we see at ETI.[29]

[28] U.S. EIA, Annual Electric Power Industry Report, Form 861 for 2016–2020; U.S. EIA, Form EIA 861M detailed data for 2021.

[29] *Id.*

ETI also trails its neighboring and peer utilities in Arkansas and New Orleans. Entergy Arkansas and Entergy New Orleans, both achieved efficiency savings of around 1.4 percent of retail sales in 2020 and Ameren Missouri achieved savings of 1.2 percent.[30]

Q What level of energy efficiency and demand response does ETI project going forward?

A ETI projects a steady decrease in incremental residential and commercial energy efficiency investment going forward, as shown in Figure 2 below. In fact, after 2030 the company projects that its annual investments in energy efficiency will actually be lower each year than it was the prior year. This indicates that as the measured life of current investments expires, ETI does not have a plan to invest in additional efficiency measures. Among leading utilities, the expiration of lighting measures could justify a near-term decline in efficiency investment. But ETI is not a leading utility. As discussed above, ETI trails other peer utilities in energy efficiency investment, with efficiency savings levels at around one-quarter the national average. This means ETI likely has a long way to go before its options for cost-effective energy efficiency investment begin to decline. It is very concerning that a company with such high growth projections is taking so few efforts to manage this load with low-cost efficiency measures.

[30] *Id.*

Figure 2: CONFIDENTIAL ETI's cumulative annual energy efficiency investment assumptions, 2010–2050

Source: Calculated based on ETI Response to TIEC Request 8-2, HSPM Attachment 1.

For demand response, [redacted] [redacted][31] This is less than [redacted] the level seen in MISO at large, where demand-response programs constitute more than 10 percent of peak load, (90 percent of which is interruptible load).[32] This lack of demand response and load management is concerning not just now, but also into the future as ETI projects a growth in the industrial sector. When asked about whether any of the new industrial customers are expected to be on the demand-response program, ETI responded in the negative and explained that the Interruptible Service (IS) tariff is

[31] Weaver WP_ABW Testimony HSPM Errata No. 2.

[32] Potomac Economics, 2020 State of the Market Report for the MISO Electricity Market, page 107 (May 7, 2021).

already fully subscribed at 5.3 percent of its retail peak load.[33] It is unclear how the tariff can be fully subscribed with such a low level of peak management, and ETI admitted it has not conducted any recent analysis on increasing the size of the IS program.[34] ETI should not be overbuilding generation capacity for highly uncertain future industrial load growth; instead, it should be leveraging the flexibility inherent in the load itself to manage its projected growth and the high level of uncertainty associated with it.

Q Did ETI consider increased investment in energy efficiency or demand-side management programs to offset part of the projected increased load?

A No. As discussed above, ETI did not consider an increase in load management or interruptible load to offset a portion of ETI's' projected future capacity needs. ETI instead referenced its compliance with Commission energy efficiency rules, indicating it only does the minimum required. ETI goes on to defend its decision to not evaluate increased investment in load management, or really any demand-side management, by asserting that expansion of demand response was not sufficient to address ETI's capacity needs.[35] This illustrates the downfall of ETI's approach in looking at the retirement of Sabine as a one-for-one replacement exercise. While it is true that demand-side management likely cannot meet the entirety of ETI's future capacity needs, cost-effective energy efficiency and demand-side management can meet some of ETI's energy and peak needs and will be part of the lowest-cost resource portfolio. ETI failed to consider energy

[33] ETI Response to Sierra Club Request 3-38(a). It is unclear why the MW of interruptible load differs between this response and the quantity provided in Weaver WP_ABW Testimony HSPM Errata No. 2.
[34] ETI Response to TIEC Request 7-7.
[35] *Id*.

efficiency or demand-side management as a flexible part of a diverse solution to its customers' capacity and energy needs.

iv. ETI's claim that it needs in-region capacity and cannot rely on MISO market purchases is unsupported.

Q How do market purchases and sales fit into ETI's near-term resource plan for meeting its system needs?

A ETI claims that "purchasing capacity credits in the MISO Planning Resource Auction ("PRA") is not an appropriate or responsible long-term solution to replacing the capacity."[36] But neither is building a 1,215 MW power plant for a highly uncertain load that may or may not materialize.

And while it may be true that relying on the MISO market for thousands of MW of capacity for decades into the future may not be the most prudent strategy, that is not what I am suggesting. Further, the Company has relied historically on market purchases (as shown in Table 1) and plans to purchase 330 zonal resource credits from the MISP PRA for planning year 2022/2023,[37] so it is unclear why market purchases are suddenly a risky unacceptable portfolio option going forward.

[36] Direct Testimony of Sallie T. Rainer, page 5.
[37] ETI Response to TIEC Request 12-8.

Table 1: ETI capacity purchases through the PRA

MISO Planning Year	Sales/(Purchases) in Planning Resource Auction
15/16	(552)
16/17	(88)
17/18	(74)
18/19	(119)
19/20	(287)
20/21	(787)
21/22	71

Source: ETI Response to TIEC Request 12-7.

The Company has framed the decision as either 1,215 MW of market purchases or a 1,215 MW CCGT, but this once again shows the flaw in its approach to resource planning. ETI should not be evaluating replacement for the capacity of the Sabine Plants, but rather procurement of resources to meet system needs after the retirement of the Sabine Plants. And part of that portfolio can be met through short- and long-term market purchases, or even capacity purchases, purchased outside of the market through a bilateral process or an RFP process. Using a portfolio approach also allows a more incremental and modular approach that will better align changing system needs and conditions with available projects. This will also allow the Company to hedge against future load growth, in the event that its aggressive industrial load projection does not materialize.

Q What is driving ETI's decision to locate the Orange County Gas Plant at the Sabine site?

A ETI claims that it needs in-region capacity based on the need to (1) respond and restore power quickly in the event of a storm or outage, particularly with the increased prevalence of hurricanes; and (2) provide inertia and dynamic reactive

support and reactive power in the region.[38] But a 1,215 MW CCGT is not the only resource that can be located in the region or provide these services. As discussed further in the next section, it is clear that ETI did not attempt to evaluate the placement of alternative resource options within the load pocket. Specifically, ETI did not even consider wind resources,[39] and it did not evaluate solar PV potential in the eastern region.[40]

Synchronous condensers can help maintain transmission system inertia in the region, and a variety of technologies, all much less expensive than a 1.2 GW gas plant, can maintain dynamic reactive support within the region.[41] These technologies include synchronous condensers, static volt-amperes reactive ("VAR") compensators ("SVCs"), and static synchronous compensators ("STATCOM"). Battery storage has the capability to provide these services as well as providing capacity and operating reserve service.

Q How does ETI's current system and near-term plan compare to its system and plan at the time it completed its modeling to select the gas plant?

A ETI's future resource plan looks substantially different now than at the time it conducted its analysis to select a CCGT as the lowest cost option. ETI began the process of replacing the Sabine Units with the Business Plan 2019 Update assumption for its supply plan, load, unit deactivations, and resource additions.[42] The Company reported the results of its portfolio analysis to its Operating

[38] Direct Testimony of Abigail B. Weaver, page 6.
[39] ETI Response to Sierra Club Request 3-11(b).
[40] ETI Response to Sierra Club Request 3-23.
[41] ETI Response to Sierra Club Request 3-2.
[42] Exhibit ABW-6 (Public), page 8.

Committee on October 16, 2019; that is nearly two and a half years ago, and seven years before the resource is projected to come online.

ETI is now on its Business Plan 2022, which shows a different resource plan than its 2019 plan. Specifically, the 2022 plan includes [redacted].[43] This includes the 100 MW Solar facility in Liberty County, and a power purchase agreement for the development of a second solar facility in its service territory that ETI has executed.[44] ETI has also acquired the Hardin County Peaking Facility from the East Texas Cooperative, Inc. and claims it seeks to increase deployment of distributed generation.[45] This means that all the analysis ETI performed to identify the CCGT plant as the lowest cost option is now obsolete and out of date. In short, the analysis evaluated a system that is fundamentally different than the one ETI is planning for today.

[43] ETI Response to TIEC Request 11-2, Attachment 1.
[44] Direct Testimony of Sallie T. Rainer, page 8.
[45] *Id*, pages 7-8.

4. ETI'S MODELING AND RESOURCE SELECTION PROCESS WAS FLAWED AND DESIGNED TO SELECT THE SELF-BUILD OPTION.

i. ETI did not robustly consider supply- or demand-side alternatives or evaluate a portfolio approach to meeting system needs.

Q Based on your experience in the industry, what are best practices for utilities to identify resources to meet future system needs?

A Utilities across the country, including ETI's sister utilities Entergy Louisiana and Entergy Arkansas, use portfolio-level planning and economic optimization analysis tools. In fact, in their 2018 and 2019 IRPs respectively, Entergy Arkansas[46] and Entergy Louisiana[47] described their use of the AURORA Capacity Expansion Model to produce "optimized portfolios." This is the same model that ETI used to conduct its "portfolio analysis," although ETI noticeably only utilized the model's production cost capabilities, and not its capacity expansion tools. This approach correctly looks at the need for additional capacity or generation on a portfolio-scale. It then relies on sophisticated economic optimization algorithms that consider a variety of options to identify a set of resources that can meet those needs.

[46] Ex. DG-7, Entergy Arkansas, Inc. 2018 Integrated Resource Plan.
[47] Ex. DG-6, Entergy Louisiana, LLC. 2019 Integrated Resource Plan.

Q Based on your review of testimony and analysis provided by ETI, did ETI use a portfolio approach or economic optimization?

A No. ETI admits directly in discovery that it did not use optimization modeling.[48] Instead, supporting analysis for this project primarily consists of three narrow and discrete analyses, designed to answer particular questions about individual resources rather than establishing the most economical path forward for ETI ratepayers. Each analysis evaluated the most economical path forward based on highly constrained assumptions and a small pre-selected set of possible solutions.

Q What are the potential consequences of failing to rely on optimization modeling, which is a resource planning best practice?

A There is no testing of the market and no evaluation of meeting all system needs. Therefore, there is no way to know whether the resource selected is the lowest cost or best meets system needs. There is also higher risk for customers with reliance on just one single resource relative to consideration of a diverse set of supply- and demand-side resources. With a large pool of resources, risk can be spread out across different resource types and supply chains.

Q Please summarize the supporting analyses provided by ETI in this proceeding.

A As discussed above, ETI relies on three analyses to justify the issuance of its RFP and ultimately its CCN for the OCAPS plant. They are:

[48] *See, for example*, ETI Response to Sierra Club Request 3-2; ETI Response to Sierra Club Request 3-33; ETI Response to Sierra Club Request 3-35.

- ETI's assessment of the appropriate retirement date for Sabine Unit 1, Unit 3, and Unit 4
- ETI's "Portfolio Analysis" that was used to identify a 2x1 CCGT as ETI's preferred resource
- ETI's Economic Evaluation used to estimate the total monetary benefits of the CCGT project

Q Please briefly describe the Sabine retirement analysis and its findings.

A The deactivation analysis evaluated the risks and quantified the economic costs and benefits associated with deactivating Units 1 and 3 relative to alternatives where the units were sustained for an additional three to five years.[49] The analysis stated that there were no safety or reliability issues associated with continuing to operate Units 1 and 3, but cited generator and boiler age and failure risk as concerns.[50] While these are certainly reasons to plan for the retirement of the units in an expedient and efficient manner, there is no binding mandate or reason that the units have to be retired by a specific year. Rather, their retirement date should be flexible enough within a reasonable range of near-term years to allow adjustment to enable procurement of the lowest cost portfolio of replacement resources.

Q Explain ETI's initial "portfolio analysis" process.

A Based on its decision to retire Sabine Units 1, 3, and 4, ETI performed a "portfolio analysis" that evaluated multiple portfolios across various market

[49] Exhibit ABW-5 (Public), page 12.
[50] *Id.*, page 14.

conditions. ETI presented the results of this analysis to the Operating Committee and chief executive officer on October 19, 2019, and the committee approved the recommendation to move forward with a 2x1 CCGT.[51]

Q Do you think the analysis propounded by ETI represents a true least-cost portfolio analysis?

A No. As discussed above, in contrast with resource planning best practices, ETI did not utilize capacity expansion modeling to identify an optimized resource or portfolio of resources to meet system needs after the retirement of Sabine Units 1, 3, and 4.[52] Instead, ETI modeled five pre-designed resource portfolios across four future scenarios using the production cost component of the AURORA modeling software (which can also be used to conduct optimized capacity expansion modeling). The four scenarios were: (1) Reference; (2) Gas Centric with even higher load growth assumptions, low gas prices, and no CO_2 price; (3) DSM (demand-side management) & Renewables with low load growth, low gas prices, more renewables, and a high CO_2 price; (4) Growth & Renewables with a high load growth, high gas prices, more renewables, and a reference CO_2 price. The Company then incorporated transmission costs, site costs, and other fixed supply costs, before conducting a high-level risk screening to inform its final recommendations.[53] This risk screening involved a thin qualitative review and simplistic ranking of the following factors for each portfolio: market risk, regional reliability, fleet modernization, executability, optionality, fuel supply diversity,

[51] Exhibit ABW-6 (Public) pages 1-2.
[52] ETI Response to Sierra Club Request 3-33.
[53] Exhibit ABW-6 (Public).

and environmental impacts.[54] No economic or optimization analysis went into the design of each portfolio. ETI defended this approach, saying that there are factors outside of economic optimization, including "economies of scale for large, combined cycle gas turbines, fuel diversity, technology and locational diversity, and supply role diversity."[55]

The problem with this approach is that ETI is focusing on replacing the capacity and generation from three specific units instead of looking at what resources broadly can meet its system needs. This is especially problematic as it does not allow the Company to adapt or reevaluate its modeling and procurement plans as system needs change. Instead, ETI would be locked into a single fossil fuel-based resource.

Q What replacement resources did ETI consider?

A The five portfolios ETI evaluated for its "portfolio analysis" represent a tightly clustered and highly similar subset of many possible resource deployments. Portfolio 2, the one ultimately selected, features the only 2x1 CCGT. All other portfolios include at least one 1x1 CCGT and combustion turbined ("CT") or reciprocating internal combustion engine ("RICE") unit with 100-200 MW of solar and storage (Portfolios 1 and 4), an additional 1x1 CCGT, or maintaining the Sabine Unit 4.[56]

[54] *Id*.
[55] ETI Response to Sierra Club Request 3-33.
[56] Exhibit ABW-6 (Public), page 12.

Q What resources did ETI not consider in its "portfolio analysis?"

A ETI did not consider wind resources, capacity purchases (short- or long-term), maintenance of Sabine Units 1 or 3, or incremental energy efficiency or demand-side management.[57] It also did not seriously consider any substantial amount of new solar PV or battery storage.

When asked about why the Company screened out wind and what analysis ETI performed to support this, ETI said "wind resources were not included in the evaluated portfolios because other technologies available were expected to provide more net benefits."[58]

When asked about solar potential evaluations in the Eastern Region, ETI indicated it had not performed any solar potential studies in the past five years.[59] But the Company did indicate that it has selected 250 MW of solar PV out of its 2019 ETI Renewable RFP and is in the process of soliciting additional solar as part of its 2021 ETI Solar RFP.[60] This indicates that solar PV is in fact an economic resource within ETI's service territory, but ETI's selection process for the OCAPS project simply did not allow it to compete as a replacement resource.

[57] ETI Response to TIEC Request 7-7.
[58] ETI Response to Sierra Club Request 3-11(b).
[59] ETI Response to Sierra Club Request 3-23.
[60] *Id*.

As discussed above, the Company also did not consider market purchases as part of its portfolio, or an increase in load management or interruptible load to offset ETI's projected future capacity needs.[61]

Q Please comment on ETI's "Market Risk" assessment.

A ETI classifies the CCGT portfolio as "reducing market risk" by reducing exposure to MISO market prices.[62] In reality, this portfolio is simply exchanging market risk, in the form of uncertain MISO prices, for stranded asset risk tied up in the initial $1.19 billion capital investment, along with sustaining investments, and commodity risk in the form of fuel prices for the proposed OCAPS unit. Given the mix of energy resources that power MISO at any given time is less gas dependent than ETI's own resource mix; concentrating risk into gas commodity risk does not reflect sound risk management strategy, especially given potential changes to the global gas regime.[63] Further, if ETI expects to sell excess generation into the MISO market, for which shareholders are entitled to 10 percent of the margins,[64] ETI is indicating it's okay with accepting market price risk as a supplier but not as a purchaser.

As shown in Figure 3 below, ETI currently relies on gas for over [redacted] of its resource mix (on a UCAP basis). The Company's resource mix is expected to change only minimally by 2026 if Sabine Units 1, 3, and 4 are retired and OCAPS is brought online [redacted]

[61] ETI Response to TIEC 7-7.
[62] Exhibit ABW-6 (Public), page 26.
[63] Exhibit ABW-6 (Public), page 26.
[64] 16 Tex. Admin. Code § 25.236(9).

[redacted][65] MISO has substantially higher fuel diversity, and only relies on natural gas for 45 percent of its capacity on a UCAP basis.[66] By 2040, its resource mix is expected to be between 48 percent gas at the high end and 33 percent at the low end, depending on the MISO future scenario modeled, as shown in Figure 3 below.[67]

Figure 3: CONFIDENTIAL ETI and MISO resource portfolio makeup by percentage for 2021 and 2039

Source: Calculated based on exhibit Weaver WP_ABW Testimony HSPM Errata No. 2; MISO Future Report. December 2021; Potomac Economics, 2020 State of the Market Report for the MISO Electricity Market, May 7, 2021, page 6.
Note: ETI 2039 resource mix only includes resources ETI current has planned, which do not meet its projected load.

[65] Weaver WP_ABW Testimony HSPM Errata No. 2.

[66] Potomac Economics, 2020 State of the Market Report for the MISO Electricity Market, May 7, 2021, page 6.

[67] MISO Futures Report, Updated December 2021. Available at: https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf.

ii. <u>ETI's RFP was extremely narrow and designed to limit competition.</u>

Q Describe the RFP process that ETI used to select the Orange County Gas Plant.

A ETI issued an RFP on April 28, 2020 for a 1,000 to 1,200 MW Combined-Cycle Gas Turbine Capacity and Energy Resource located in the Eastern Region of ERI's service territory. The resource was required to commence service between May 2025 and May 2026.[68]

Q Do you have any concerns with the scope of the RFP?

A Yes, I have several concerns with this RFP. First, the RFP is extremely narrow in scope, and is therefore not likely to deliver the lowest cost option for ETI ratepayers. Second, the RFP requires a specific type and size of fossil resource to be located in a specific region and to be online by a specific date. But ETI does not fundamentally need a 1,200 MW CCGT in East Texas by 2026. ETI needs a resource, or portfolio of resources, that can meet its system needs in the Eastern Region of Texas in the 2025–2026 timeframe and beyond; but there is nothing binding ETI to that date, resource type, or even that location. By dictating these narrow terms, ETI is all but removing the possibility that any other projects can compete with its self-build option to provide the energy and capacity that its customers actually need. Third, ETI is not able to test the market to determine the least-cost way to serve ratepayers the way it would with an all-source RFP. Instead, it is locking ratepayers into the cost of one resource option.

[68] Exhibit PDN-1, page 5.

Q Provide a timeline of the RFP process.

A My understanding of the timeline is as follows:[69]

- Beginning of 2020: The RFP was developed.
- February 7, 2020: A Notice of Intent letter was sent out to interested parties.
- March 2020: Bidders conference was held.
- April 28, 2020: RFP was issued.
- June 30, 2020: Bidder registration deadline.
- August 21, 2020: ETI's Self-build proposal was due.
- August 24–August 27, 2020: Third-party proposals were due.

The concerning thing about this timeline is that the entire process happened during the early months of the COVID-19 pandemic (April–August 2020). At the Bidders Conference in March, only three parties participated—two were from a third-party organization and one was with the self-build team.[70]

On April 1, 2020 ETI asked for feedback from bidders on maintaining its original timeline.[71] And in fact, on April 7, 2020, ETI received an email from a potential bidder, Southern Power, stating:

> The immediate feedback we would have pending the release date of the final version would simply be the expected response date given the pandemic across the country. Depending how long shelter in place orders remain both nationally and state by state will certainly have a direct

[69] *Id*, pages 29-30.
[70] Exhibit WJO-3, Errata to Oliver Direct Testimony, page 18.
[71] Workpaper PDN, page 6.

impact on our ability to appropriately respond to the RFP. Any date further out in 2020 gives us, and others a better chance to reply in full.[72]

But ETI ignored this feedback and moved forward with the RFP on its planned timeframe.

Q What was the outcome of the RFP?

A Only one bid was submitted. This bid was for ETI's self-build CCGT option. The Independent Monitor (IM), Mr. Wayne Oliver of Merrimack Energy Group, indicated that this was only the second time in his career where an RFP attracted no eligible bids from entities other than the host utility (the other time was back in 2005).[73] Mr. Oliver has been an IM or independent evaluator, or independent consultant on more than 125 competitive procurement processes across 20 states and 3 Canadian Provinces.[74] This means that during his career, less than 2 percent of RFPs that he's reviewed have had no competitive responses.

Q Did ETI or the IM make any efforts to adjust the schedule based on the potential impact of the pandemic?

A No. Despite the low turnout at the Bidders Conference, and zero third-party bidders registering by the June 30, 2020 deadline, neither ETI nor the IM made any changes to the process or sought to extend the timeline to accommodate more interested parties. Nor did ETI appear to ever consider issuing a less restrictive RFP that sought defined amounts of energy and capacity, without proscribing a

[72] Application of ETI to amend its CCN to construct OCAPS, WP/PDN Testimony, page 12.
[73] Wayne J. Oliver Response to TIEC Request 2-16.
[74] Exhibit WJO-3 (Public), pages 6-7.

specific resource. When asked in discovery whether he thought the timeline impacted ETI receiving zero bids, Mr. Oliver responded that he didn't have firsthand knowledge of how the pandemic impacted bidders' business plans but didn't think so based on other solicitations Merrimack Energy said it was involved in for renewables and battery storge projects.[75]

Q What did the IM conclude about the reasonableness of the RFP process?

A Mr. Oliver concluded that the project was "undertaken in a fair, equitable and unbiased manner."[76] Despite this high level conclusion, Mr. Oliver also expressed measured concern about the process, observing that: "The lack of competition raised the issue whether the project pricing was reasonable and whether it should be approved without the presence of competitive options."[77] He ended his report with the following: "The reason why competition was limited was not clear to IM. While there may be a market perception that ESL has a competitive advantage associated with the self-build option, this view was not raised by any bidder. The IM did not experience any instances where it appears that the self-build option was treated preferentially."[78]

It is concerning that despite expressing concern about the lack of competitiveness of the process, Mr. Oliver ultimately doesn't make any specific statements about the limits placed on the process by the timing of the release, the scope of the procurement, or the terms of the RFP.

[75] Wayne J. Oliver Response to TIEC Request 2-19.
[76] Exhibit WJO-3 (Public), page 53.
[77] *Id*.
[78] *Id*, page 57.

Q Has ETI issued any similar RFPs in the recent past that also resulted in the selection of a self-build option?

A Yes. On June 26, 2015, ETI issued an RFP for a 1,000 MW CCGT in Western Texas. In this RFP, four proposals representing three projects were received from three separate bidders. Entergy's self-build option of the Montgomery County Power Station, a 993 MW CCT placed in service on January 1, 2021 in the Western Region,[79] was selected through this process.[80]

Mr. Oliver was the IM for this RFP as well and made a nearly identical statement in his IM report for this RPF regarding the limited competition he observed in the RFP process, stating:

> The reason why competition was limited was not clear to the IM. While there may be a market perception that ESI has a competitive advantage associated with the self-build option, this view that has not been raised by any bidder. The IM did not experience any instances where it appeared that the self-build option was treated any differently from any other proposal.[81]

He also discussed a contentious issue with accounting terms that came up during this RFP process stating:

> One of the most contentious and uncertain issues festering in the RFP process was the accounting issues associated with lease treatment and its

[79] Direct Testimony of Sallie T. Rainer, page 7.
[80] Ex. DG-8, Docket 46416, Exhibit WJO-3 (Redacted IM Report for ETI RFP), page 5.
[81] *Id.*, page 60.

> implications for utility accounting for third-party power purchase agreements and tolling agreements. While this issue was of considerable concern to ESI, the Company took important steps in conjunction with the Bidders to attempt to resolve these issues prior to selection of the preferred proposals rather than eliminate any proposals from consideration.[82]

This same issue appears to be at play in this RFP.[83] Given Mr. Oliver's identification of this as a contentious issue in the prior RFP, and his experience with at least one other ETI RFP where the self-build option prevailed, it is rather baffling that he has no clarity on why competition was limited. If the terms of the prior RFP were unfavorable, the entire process was perceived as skewed towards the self-build option, and then the self-build option did in fact prevail, an expert in the field should be able to reasonably observe that a nearly identical RFP issued years later will likely entail the same concerns with competitiveness.

Q Does ETI's RFP process appear to comply with the best practices of resource procurement?

A No. As discussed above, ETI placed unnecessary constraints on this procurement process. Best practices are to issue an all-source RFP to test the market, and then incorporate the results into robust optimized capacity expansion modeling to determine which resources, in combination or alone, can best meet system needs. Issuing a narrow and constraining RFP, such as ETI did here, is absolutely not best practice. In fact, one needs to look no further than Mr. Oliver's Experience Statement document (Exhibit WJO-2) to see this. Since 2015, Mr. Oliver has been involved in 64 RFP processes. ETI's two CCGT RFPs for Montgomery County

[82] *Id.*, page 59.
[83] ETI Response to TIEC Request 2-21.

and OCAPS are the only two procurement processes that narrowly limited respondents to a single, large combined-cycle resource.

5. THE ECONOMIC COSTS AND ENVIRONMENTAL IMPACTS OF BUILDING THE PLANT WILL LIKELY BE SUBSTANTIALLY LARGER THAN ETI PORTRAYS.

i. ETI's calculation of $1.85 billion in savings is based on a skewed and inappropriate baseline.

Q What does ETI claim about the economic benefits the plant will deliver?

A ETI claims that the gas plant will deliver $1.85 billion ($2020) in net benefits to ratepayers over the units' lifetime[84] (ETI's original calculation was $1.6 billion, but it was later updated to $1.85 billion).[85] ETI's modeling also showed that the project is expected to operate at a capacity factor of [redacted] for the entire study period.[86]

Q What analysis did ETI perform to find these purported savings?

A ETI completed what it called The Total Supply Cost Analysis using the production cost component of the AURORA simulation model, with projected capacity value, non-fuel operating costs, transmission costs, and other capital costs layered on later.[87]

[84] Direct Testimony of Phong D. Nguyen, page 3.
[85] *Id.*, page 19.
[86] ETI Response to OPUC Request 1-4, Attachment OPUC 1-4 HSPM.
[87] *Id.*, page 16.

This analysis compared the total cost of supplying service to customers with the OCAPS plant to the levelized cost of meeting resource needs with CTs and market energy purchases.[88] This is an interesting comparative exercise, and such analysis can be useful for screening purposes; but in this context, the $1.85 billion in savings is little more than a manufactured calculation intended to distract from the fact that ETI is trying to build a $1.19 billion dollar gas plant without robustly considering alternatives.

Q Explain the flaws in ETI's modeling.

A First, and most fundamentally, CTs are not energy resources; they are capacity resources. ETI modeled three CTs operating at a capacity factor of around [redacted].[89] In contrast, ETI projects that OCAPS will operate at a capacity factor of [redacted] for the entire study period.[90] Modeling a capacity resource with such a low capacity factor as a baseline alternative to a high capacity factor energy resource does not provide an apples-to-apples comparison.

Second, ETI projects OCAPS will operate at a sustained capacity factor of [redacted] over the next few decades. It is unlikely that even a new CCGT plant will operate at a level that high based on both (1) historical data on combined cycle unit operations, and (2) future projections that increasing penetrations of zero variable cost wind and renewables on the grid will displace fossil resources in many hours and drive an increase in fossil unit cycling. This aggressive capacity

[88] *Id.*, page 15.
[89] ETI Response to TIEC Request 4-4, Attachment TIEC 4-4 HSPM.
[90] ETI Response to OPUC Request 1-4, Attachment OPUC 1-4 HSPM.

factor assumption is concerning because it will produce higher energy revenues in ETI's modeling of OCAPS than are likely to materialize in reality.

Third, ETI assumed the three baseline CTs were also converted to operate on hydrogen.[91] ETI claims this was done to make the comparison apples-to-apples, but all this did was remove the cost of installing hydrogen co-firing capabilities from the cost savings analysis. If ETI believes that the decision to install technology to co-fire on hydrogen provides system benefits and is in the best interest of customers, then it should include the expected costs to add the technology and the expected savings that will result to the OCAPS part of the analysis. But ETI admits that its economic analysis "included the costs to enable hydrogen co-firing but has conservatively reflected none of the potential benefits associated with the investment."[92]

Fourth, ETI's modeling methodology was very simplistic. Once again, the Company conducted no optimized capacity expansion modeling.[93] It modeled only three years, 2027, 2031, and 2040,[94] and extrapolated results for the remaining years. ETI also did not model the plant co-firing on hydrogen.[95] This exercise seems designed just to deliver a large, purported cost savings to justify the OCAPS project.

Finally, ETI modeled no load growth sensitivity to evaluate the expected costs or savings if the projected industrial load did not materialize. In this case, the

[91] Direct Testimony of Phong D. Nguyen, page 24.
[92] ETI Response to Cities Request 1-5.
[93] ETI Response to Sierra Club Request 3-32; ETI Response to Sierra Club Request 3-33.
[94] ETI Response to TIEC Request 1-19 (c).
[95] ETI Response to Cities Request 1-6 (a).

Company would either have to reduce how much it operates OCAPS or sell more energy into an uncertain energy market.

Q How does ETI believe the OCAPS project will benefit ETI ratepayers?

A ETI characterizes the OCAPS unit as a "highly efficient generating unit with a low heat rate and a low variable dispatch cost" and says that it expects the unit to be dispatched at a high capacity factor and reduce ETI's energy deficit.[96] The Company believes that the unit will deliver benefits to ratepayers by delivering the following:

1. Lower MISO locational marginal prices (LMP)[97]
2. Fuel cost savings, which ETI calculated to be $109 million in the first year, and reduced fuel factor charges[98]
3. Reduced exposure to volatile energy market prices[99]
4. Reduced exposure to capacity market prices in the MISO south market that are expected if capacity from Sabine is not replaced[100]

Q How do you respond to these claims?

A As discussed above, all these claims around lower LMPs, reduced fuel costs, and reduced market volatility are based on ETI's faulty and simplistic analysis. ETI has not structured an appropriate analytical exercise comparing the CCGT to multiple, diverse resource portfolios (consisting of renewable energy supply and

[96] ETI Response to OPUC Request 1-7.
[97] Direct Testimony of Abigail B. Weaver, page 5.
[98] *Id*.
[99] *Id*.
[100] *Id*.

battery storage for capacity) to test its assertion that the portfolio with OCAPS minimizes risks to ratepayers of high LMPs, market price volatility, and fuel costs. Instead ETI relied on the results of its somewhat academic analysis that compares the system with the OCAPS CCGT to a system with three CTs to support its assertions the CCGT minimized risks for ratepayers. But really all it showed is that risks are lower when you build a 1,215 MW combined cycle plant relative to building a few peaking resources and relying on the market for the rest of the services.

And what ETI has omitted in its discussion of the potential benefits of OCAPS is the substantial risk it is imposing on ratepayers with such a large and capital-intensive plant. Specifically, the risk that:

1. Projected load doesn't materialize,
2. Market prices fall and the potential to earn revenue by selling excess generation into the market is reduced,
3. Gas prices rise or become more volatile, or supply is somehow limited,
4. The cost of renewables and battery storage continues to fall, making OCAPS energy less desirable relative to zero marginal cost energy,
5. The plan operates at a materially lower average annual capacity factor because it is displaced during many hours by zero marginal cost wind output,
6. Green hydrogen does not become economically available,
7. Future regulations limit carbon emissions and make the unit more expensive to operate, or even obsolete, and
8. The project experiences construction delays, supply chain challenges, cost over-runs, or any other challenges that could be minimized with a more diverse portfolio staggered to better align with the timing of system needs.

ii. Synapse modeling shows that ETI's system needs can likely be met at the lowest cost by adding solar PV and battery storage once the Sabine units come offline.

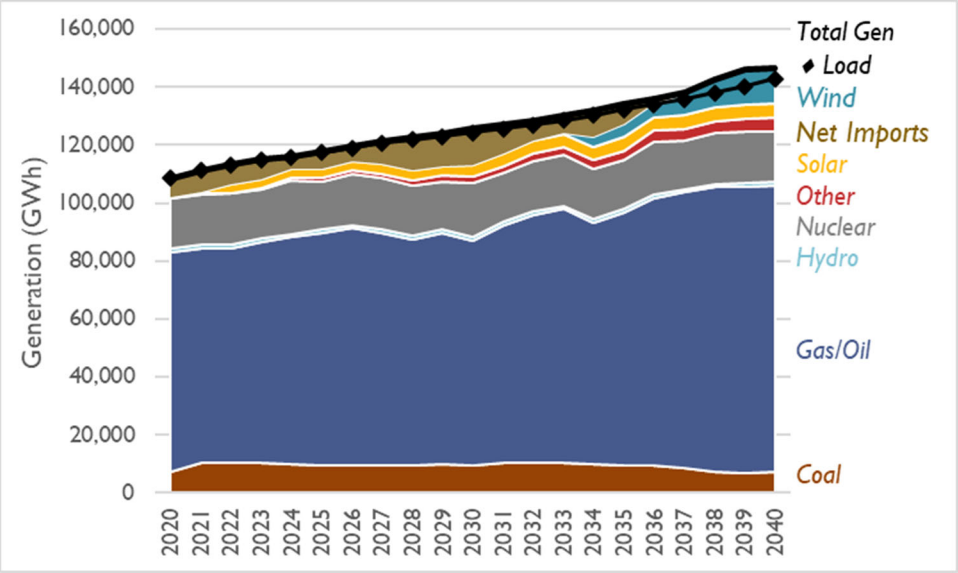
Q Did you conduct any analysis or modeling yourself to evaluate the reasonableness of ETI's selection of the OCAPS plant?

A Yes. Using the EnCompass capacity expansion and production cost model, I modeled the entire MISO market to evaluate the optimal resource mix for MISO Zone 9, the home of ETI, during this time period. I also conducted a high gas price sensitivity run. I evaluated the resource mix and the resulting market prices for both scenarios.

Q What does your analysis show?

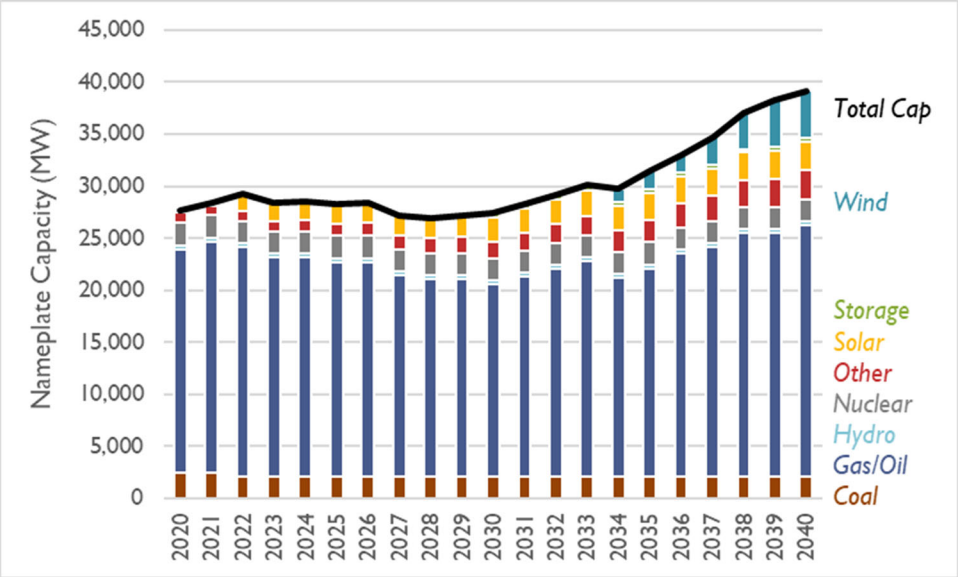
A My analysis shows that under current market conditions, a large, combined-cycle unit is not necessary in MISO Zone 9, and is not the lowest cost resource option to meet ETI's system need. Specifically, I conducted an optimized capacity expansion modeling run for the MISO region, and the model economically selected to build approximately 1,500 MW of new solar PV and 275 MW of battery storage by 2026. The model did not opt to build any new combined-cycle gas resources in MISO Zone 9 prior to 2031. The projected generation profile and nameplate capacity for the zone is shown in Figure 4 and Figure 5 below. As these figures show, there is already a substantial quantity of gas capacity in MISO Zone 9. Specifically, our modeling shows there are over 22 GW of gas resources in Zone 9, around half of which are made up of combined-cycle capacity. In total, gas resources make up 78 percent of the region's capacity and account for around 67 percent of the region's generation mix in 2021.

Figure 4: Generation resource mix for MISO Zone 9, 2020-2040



Source: Synapse modeling in EnCompass with data from the Horizons Energy National Database.

Figure 5: Nameplate capacity for MISO Zone 9, 2020-2040

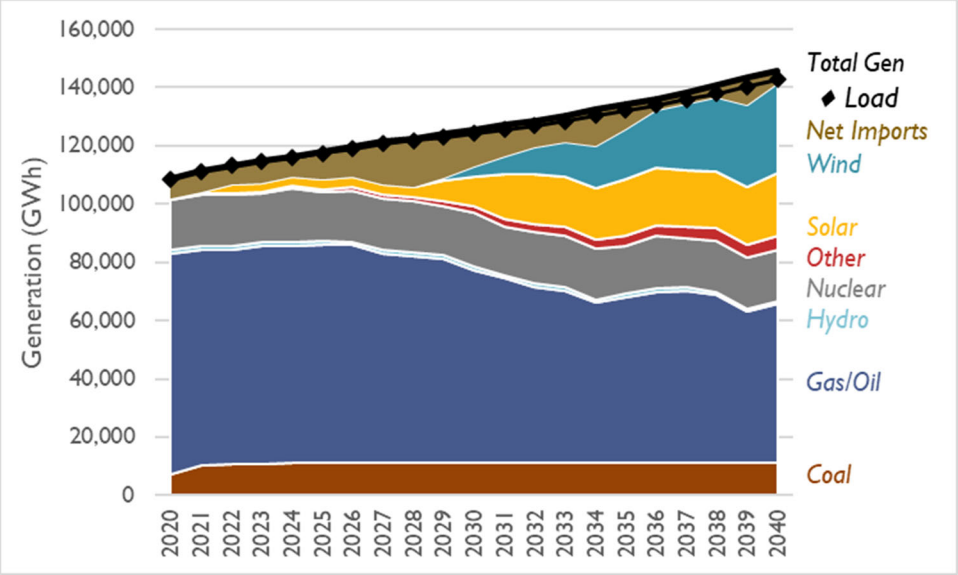


Source: Synapse modeling in EnCompass with data from the Horizons Energy National Database.

Q What did you find when you modeled a high gas price sensitivity?

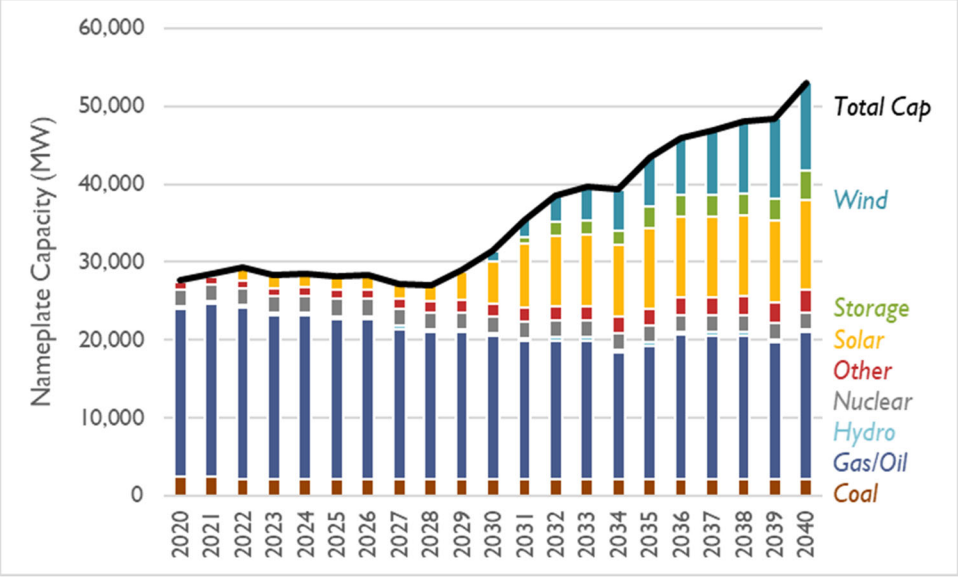
A The model selects to build the same quantity of solar PV and battery storage in the near term (2026) under the high gas assumptions. But it builds half as much gas in the 2030s and relies on more wind, solar PV, and battery storage for both generation and capacity, as shown in Figure 6 and Figure 7 below. There is an increased buildout of renewables in this scenario (relative to the reference scenario) to offset thermal generation that is now uncompetitive under higher gas prices. Note that the "gas" resources that are selected by the model in the 2030's should be thought of more as placeholders for future firm capacity resources rather than new gas resources.

Figure 6: Generation resource mix for MISO Zone 9, 2020-2040, high gas price sensitivity



Source: Synapse modeling in EnCompass with data from the Horizons Energy National Database.

Figure 7: Nameplate capacity for MISO Zone 9, 2020-2040, high gas price sensitivity



Source: Synapse modeling in EnCompass with data from the Horizons Energy National Database.

Q What are the main differences between your modeling assumptions and ETI's?

A I modeled a load forecast for MISO Zone 9 with lower future load growth assumptions than ETI assumed. My modeling assumed around a 7 percent increase in energy and peak demand between 2021 and 2026, compared to ETI's assumption of a 10.3 percent increase in peak demand.[101]

Specifically, my peak demand and annual energy assumption were taken from the *2021 MISO Energy and Peak Demand Forecasting for System Planning* report published by the State Utility Forecasting Group at Purdue University.[102] I relied on Purdue's 2020 energy efficiency assumptions, as the forecasting group did not include energy efficiency in its 2021 forecast. For electrification assumptions, I relied on the *MISO Futures* report (Futures 2 scenario), which assumed a medium scenario for electrification and a moderate scenario for technology advancement. In total, my peak load forecast for MISO Zone 9 increased at a compound annual growth rate ("CAGR") of 1.45 percent while the annual energy forecast for Zone 9 increased at a CAGR of 1.38 percent.

This critically allowed me to test ETI's system needs under a lower future load forecast where all its assumed industrial load projected to come online by 2026 does not materialize.

[101] Direct Testimony of Abigail B. Weaver, page 11.

[102] State Utility Forecasting Group, *2021 MISO Energy and Peak Demand Forecasting for System Planning*. Available at: https://www.purdue.edu/discoverypark/sufg/docs/publications/MISO/MISO%20forecast%20report%202021.pdf.

Q Please explain your methodology in greater detail.

A I used the EnCompass capacity expansion and production cost model, licensed from Anchor Power Solutions, to simulate the Eastern Interconnect over a 20-year period from 2021 through 2040. I modeled each year in capacity optimization mode to determine the most cost-effective capacity additions throughout the analysis period. The simulation used a "typical on-peak/off-peak day," in which two days are used to represent the characteristics of each month.

Q Is the purpose of this modeling to definitively identify a portfolio of resources that would more cost-effectively replace the Sabine units?

A No. The purpose of my analysis is to show what resource types are competitive in the market today and what type of analysis ETI *should* be conducting to meet its future system needs. Specifically, ETI should not be pre-selecting resources and plugging them into a production cost model. ETI should be conducting an all-source RFP to test the market, and then feeding the results of its RFP into an optimized capacity expansion model to evaluate which options provide the lower-cost portfolios for ratepayers.

iii. ETI claims that the Orange County Gas Plant will be cleaner and efficient, but it will result in over 110 million tons of lifetime emissions that could be avoided with a cleaner portfolio.

Q How does ETI describe the environmental attributes of the Orange County Gas Plant?

A ETI describes it as a "clean"[103] energy resource that will provide "sustainable and affordable electricity."[104] Specifically, because the plant has a lower heat rate than the Sabine plants it is replacing, and because ETI is proposing to install dual-firing technology on the plant so it can run 30 percent on hydrogen, ETI is framing it as a clean energy resource.

Q Is the Orange County Gas Plant a clean energy resource?

A No. First, the Company plans to use grey hydrogen when the plant first comes online,[105] meaning its hydrogen supply will itself rely on gas for production. Operating OCAPS on grey hydrogen will not provide any environmental benefits from dual firing, and if anything will be more environmentally impactful than burning gas alone.

Second, the plant is assumed to operate at just below a [redacted][106] capacity factor over its lifetime, which would work out to over 110 million tons of CO_2

[103] Direct Testimony of Sallie T. Rainer, page 4.
[104] *Id,* page 8.
[105] ETI Response to TIEC Request 1-8(a).
[106] ETI Response to Cities Request 2-2, HSPM Attachment BP 21 Unit Valuation Orange County Power Station Sendout.

emissions emitted into the atmosphere over its lifetime. This would create a significant compliance risk for ETI and its customers, if built. ETI claims that because OCAPS is projected to have a heat rate that is 40 percent more efficient than the Sabine Units that OCAPS is replacing[107] then it will provide a net environmental benefit. But this is absolutely false. The reality is that ETI is attempting to lock in another 1 GW of fossil capacity, adding to the nearly 1 GW it just brought online in early 2020 at the Montgomery plant. If OCAPS is approved, ETI will have over 2 GW of fossil capacity locked in beyond 2050.

Q How does the plant align with Entergy's corporate carbon goals?

A It doesn't. Entergy has a zero carbon by 2050 corporate goal. The OCAPS project has a 30 year lifetime. That means that it will still be online, burning gas, through at least 2056, or else it will become a stranded asset for ETI ratepayers. ETI claims that it is committed to achieving net-zero emission by 2050, but says it is too early to commit to any specific path to net-zero.[108]

Q What does ETI say about the Company's decision to make the plant hydrogen compatible?

A ETI plans to install co-firing technology at OCAPS to make the plant capable of co-firing up to 30 percent on hydrogen. This is projected to cost $65 million, or 5 percent of the total project budget.[109] ETI claims that installing co-firing technology will provide economic and reliability benefits of a dual-fuel resource

[107] Direct Testimony of Abigail B. Weaver, page 5.
[108] ETI Response to TIEC 5-6(b).
[109] Direct Testimony of Sallie T. Rainer, page 8.

and reduce the cost and outage to expand OCAPS hydrogen capabilities if needed in the future.[110] ETI also claims that the benefits of this investment are "consistent with the nationwide transition toward a low-carbon economy" and goes on to state that "OCAPS' hydrogen capability will help ensure ETI's customers are well positioned for whatever federal policies and market condition prevail over the coming decades."[111]

Q Do you have any concerns with the Company's plan to invest $65 million upfront in dual-fuel technologies?

A Yes, I have many concerns. ETI is proposing to saddle ratepayers with an unproven technology that (a) will not actually make its system any more reliable than just operating on gas alone and (b) is also projected to increase the carbon intensity of the unit relative to just operating on gas. In fact, ETI admits that it is not aware of any other utility-scale combined-cycle gas plants in the United States that use hydrogen as a supplemental fuel.[112]

Q Has ETI demonstrated that the plant will be able to provide the touted reliability benefits based on its dual-fuel ability?

A No. ETI acknowledged that the majority of the hydrogen supply in Southeast Texas is derived through a process that uses gas as an input. This means its prospective hydrogen supply is "dependent on the availability of natural gas."[113]

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[110] *Id.*, page 6.
[111] Direct Testimony of Sallie T. Rainer, page 6
[112] ETI Response to TIEC Request 1-12.
[113] ETI Response to Staff Request 1-8.

ETI defends its claims around the reliability benefits of the dual-fuel capabilities by stating that some of the supplies with which it is negotiating have storage caverns and lateral pipelines.[114] But this is a speculative and uncertain position that the Company absolutely should not be allowed to plan around.

The reality right now is that in the event of a gas shortage, ETI's hydrogen supply would be impacted by the same forces limiting its own gas supply. In other words, ETI's claim that "[i]nvesting in these hydrogen capabilities now will not only provide *immediate* reliability benefits…"[115] is not accurate. To the extent that ETI's hydrogen supply is dependent upon natural gas, the plant's dual-fuel capabilities will provide no reliability benefits in the event of gas shortage or disruption, such as was experienced during winter storm Uri.

Q Is there evidence that OCAPS will have a lower emission rate when operating on hydrogen?

A No. ETI admits that "the extent to which carbon emissions are reduced by co-firing hydrogen with natural gas varies depending on the source of hydrogen utilized."[116] [redacted][117]

[114] *Id.*
[115] Direct Testimony of Sallie T. Rainer, page 6 (emphasis added).
[116] ETI Response to OPUC Request 1-15.
[117] ETI Response to OPUC Request 1-15, HSPM Attachment 1.

[redacted] When taking into account full lifecycle emissions, grey hydrogen is estimated to have an emissions rate around 30 percent higher than gas alone.[118]

[redacted][119] but there is no evidence that any of the hydrogen pipelines that run near OCAPs would supply green hydrogen. ETI has admitted that it has not yet entered into any commercial agreements with supplies for green hydrogen,[120] and the Company states only that it "anticipates utilizing lower carbon hydrogen over the long-term, including green hydrogen, when available and economically attractive."[121] This means that ETI's mention of the plant's co-firing capabilities as part of its claim that "Modern pollution controls and the ability to co-fire hydrogen will make OCAPS one of the cleanest resources in ETI's portfolio" is disingenuous at best, and untruthful at worst.[122] Further, it ignores the fact that producing green hydrogen itself would require the buildout of a large quantity of renewables. These are renewables that could be used to generate electricity directly instead of being used as in input into hydrogen production.

[118] ETI Response to Staff 6-1.

[119] *Id.*

[120] ETI Response to Sierra Club Request 3-3; ETI Response to OPUC Request 1-2; ETI Response to Staff Request 3-3.

[121] ETI Response to TIEC 1-8(b).

[122] Application of ETI to amend its CCN to construct OCAPS, page 3.

Q Regardless of environmental impact, is hydrogen currently economically competitive as a fuel source?

A No. Hydrogen is currently substantially higher cost than gas, and is likely to remain this way beyond OCAPS' proposed online date. [redacted][123] [redacted].[124]

Q What do you conclude about the environmental impact of OCAPS?

A ETI has framed the OCAPS project as clean and aligned with future environmental goals. But the plant is projected to contribute over 110 million tons of CO_2 to the atmosphere over the next three decades. Additionally, the dual-firing technology ETI is proposing to install at the plant to allow operation on hydrogen and gas will not improve reliability. Instead, it will allow ETI to charge ratepayers tens of millions of dollars for speculative technology that is projected to be both more costly and more environmentally damaging than operating the plant exclusively on gas.

[123] ETI Response to Staff Request 3-4 HSPM.
[124] ETI Response to TIEC Request 12-5 HSPM.

Q Does this conclude your testimony?

A Yes.