EARTHJUSTICE

July 31, 2026

<u>Overnight Delivery</u>
Ms. Kris Abel
Records and Recording Division
Louisiana Public Service Commission
Galvez Building, 12th Floor
602 North Fifth Street
Baton Rouge, Louisiana 70802

Re: Application for Approval of Generation and Transmission Resources and for Other Relief Pursuant to the Commission's *Lightning Initiative*, **Docket No. U-37882**

Dear Ms. Abel:

I have enclosed, on behalf of the Alliance for Affordable Energy and Union of Concerned Scientists, the original and two copies of the Non-Confidential Public Version of the Direct Testimony and Exhibits of two witnesses. I also have included two USB flash drives, each of which contains one expert's non-confidential Direct Testimony.

In addition, I have also enclosed the original and two copies of the **Confidential** Version of the Direct Testimony and Exhibits of the same two witnesses. The confidential version contains information that is designated either Highly Sensitive Protected Material or Attorney Eyes Only and is being provided to you under seal, in separate envelopes, pursuant to the provisions of the LPSC General Order dated August 31, 1992, and Rules 12.1 and 26 of the Commission's Rules of Practices and Procedures. Finally, I have also included two USB flash drives, each of which contains one expert's Confidential Direct testimony.

Thank you in advance for your assistance and cooperation and please do not hesitate to contact me should you have any questions or concerns.

Respectfully submitted,

Susan Stevens Miller

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Counsel for the Alliance for Affordable Energy and the Union of Concerned Scientists

CERTIFICATE OF SERVICE

I hereby certify that on this 31st day of July, 2026, I served copies of the foregoing testimony upon all other known parties of this proceeding by electronic mail, and served the Confidential version of this pleading upon all parties entitled to receive HSPM/AEO material.

Respectfully submitted,

Susan Stevens Miller

Susan Stevens Miller, Esq.

STATE OF LOUISIANA

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

IN RE*: APPLICATION FOR APPROVAL OF GENERATION AND TRANSMISSION RESOURCES AND FOR OTHER RELIEF PURSUANT TO THE COMMISSION'S *LIGHTNING INITIATIVE	)	**DOCKET NO. U-37882**

Direct Testimony and Exhibits of

Edward Burgess

On Behalf of the

Alliance for Affordable Energy and

Union of Concerned Scientists

Public Version

July 31, 2026

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<u>EXHIBITS</u>

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Edward Burgess. I am a Founding Partner of Current Energy Group LLC (CEG). My business address is 4764 E Sunrise Drive #508, Tucson, Arizona 85718.

Q. Please summarize your professional and educational background.

A. I have spent over thirteen years working as a consultant in the energy and utilities industry. I specialize in electric utility issues including utility resource planning, transmission planning, fuel and power purchase costs, rate design, revenue requirements, distributed energy resource programs, and electric vehicle programs. Prior to co-founding CEG in 2024, I was a Consulting Partner at Strategen Consulting (Strategen), where I worked for over eight years. While at Strategen, I directed the grid planning practice area. I also helped launch and served as the inaugural Director for the Vehicle-Grid Integration Council and grew the organization to over forty member companies. Prior to joining Strategen, I also worked as an independent consultant, providing technical support to clients before state utility commissions and legislatures. During that time, I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council.

Regarding my education, I have a bachelor's degree in Chemistry (A.B.) from Princeton University. I also have master's degrees in Solar Energy Engineering and Commercialization (P.S.M.) and in Sustainability (M.S.) both from Arizona State University. My resume is attached as Burgess Direct Exhibit EB-2.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Alliance for Affordable Energy and the Union of Concerned Scientists (together, the "Nonprofit Organizations" or "NPOs").

Q. Have you ever testified before this Commission?

A. Yes. I have testified on behalf of the Alliance for Affordable Energy in Entergy Louisiana, LLC's ("ELL" or "Entergy" or "Company") Application for a Certification to Deploy Natural Gas Distributed Generation (Docket No. U-36105).

Q. Have you ever testified before any other state utilities commissions?

A. Yes. I have provided expert testimony on over thirty occasions before thirteen state utility commissions including California, Colorado, Indiana, Massachusetts, Michigan, Nevada, North Carolina, Oregon, South Carolina, Virginia and Washington. A full list of these proceedings is provided within Burgess Direct Exhibit EB-2. Additionally, I have represented numerous clients by conducting technical analyses, drafting formal comments, and participating in technical workshops in a wide range of proceedings at utilities commissions in Arizona, the District of Columbia, Maryland, Minnesota, Montana, New Hampshire, New York, North Carolina, Ohio, Oregon, Pennsylvania, and Utah. I also have experience participating in matters before the Federal Energy Regulatory Commission, the Western Interstate Energy Board, and the California Independent System Operator.

II. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize the findings from your review of ELL's application.

A. My findings are as follows:

1. ELL's proposal exposes existing customers to substantial cost risk resulting from a $16 billion investment being pursued on a compressed timeframe with minimal planning analysis and the suspension of rules designed to provide customer protection.

2. The terms of the Electric Service Agreement ("ESA") do not sufficiently insulate customers from risk exposure. There are at least four major gaps in the proposed ESA framework that are described in Section V of my testimony.

3. The proposed development timeline poses significant execution risk due to overlapping target dates for generation construction.

4. There are alternative resource pathways that could meet the customer's near-term load ramp while allowing appropriate time for Commission deliberation and competitive solicitation. This alternative would minimize the risks to existing customers from rushing to lock in fixed costs for 7 new combined cycle generators.

Q. Can you please summarize your recommendations?

A. Yes. My recommendations are as follows:

- *Recommendation 1: Direct ELL to implement a more staggered implementation schedule for constructing CC units 1 through 7*
- *Recommendation 2: Limit immediate Public Service Commission ("PSC") approval to Richland Units 1 and 2 ("Group A") and address Richland Units 3-4 ("Group B") and Pointe Coupee Units 1-3 ("Group C") at a later date.*
- *Recommendation 3: The PSC should ensure ELL does not unfairly shift risk from shareholders to existing customers through the election of Retained Generator status upon termination. Approval of Retained Generator status should follow the decision process outlined in Section V-A below.*
- *Recommendation 4: If Retained Generator status is elected and approved upon early termination, the net plant for such generators should be ineligible for general cost recovery until the end of the original 20-year ESA term, and other specific Commission-established criteria are met.*
- *Recommendation 5: The PSC should require ELL to seek stronger collateral and insurance requirements beyond the proposed levels, including requiring* [redacted] *equal to a minimum of 50% of the remaining net plant.*
- *Recommendation 6: The PSC should direct ELL to develop a cost allocation approach designed to ensure that the benefits from the Customer's revenue are broadly shared.*
- *Recommendation 7: In the event of non-renewal at the end of the ESA term, retail rate recovery of the remaining Net Plant should be capped at $2 billion starting in 2048 if determined to be used and useful by the Commission.*

III. OVERVIEW OF ELL'S APPLICATION AND SUPPORTING ANALYSIS

Q. Please provide a summary of ELL's requests in this proceeding.

A. ELL is requesting Commission approval of a portfolio of generation, storage, and transmission resources to serve a new hyperscale data center customer, Evest LLC ("Customer" or "Evest"), a wholly owned subsidiary of Meta Platforms, Inc. ("Meta"), which plans to construct a data center facility in Richland Parish, Louisiana ("Project Evest").[1,2]

ELL's requests fall into the following categories:[3]

- *Certification of generation and storage resources under the 1983 General Order:* ELL seeks Commission certification that seven 1x1 combined cycle combustion turbines ("CCCT") totaling approximately 5.3 GW and three battery energy storage ("BESS") facilities totaling [redacted] MW serve the public convenience and necessity. Because ELL proposes to construct the CCCTs as utility-owned self-build resources without having conducted a competitive request for proposals ("RFP"), ELL seeks a finding that the Application satisfies the criteria of the Commission's Lightning Initiative, which would waive the competitive solicitation requirements of the Market-Based Mechanisms ("MBM") Order. Alternatively, ELL requests a good-cause exemption from the MBM.
- *A public interest and siting finding for ELL-funded transmission under the Transmission Siting Order*: ELL seeks a finding that the WFC–St. Landry 500kV Line and St. Landry Switching Station are in the public interest and appropriately sited.
- *Exemption findings for customer-funded transmission*: ELL seeks findings that the customer-funded transmission facilities (including the Smalling–El Dorado 500kV Line, 20–30 miles of 230kV interconnection lines, and nine auxiliary 230kV switching stations) are exempt from the Transmission Siting Order.

[1] Direct Testimony of Phillip May at 4:1-3 ("May Direct").

[2] Meta is also the ultimate parent of Laidley, LLC, the electric service customer for an adjacent large computing facility in Richland Parish that was the subject of last year's Docket No. U-37425.

[3] Application of Entergy Louisiana, LLC for Certification of Generation and Transmission Resources and for Other Relief Pursuant to the Commission's Lightning Initiative, at 27-35 (Mar. 25, 2026) ("Application").

- *Other rate, accounting, and sustainability approvals*: ELL seeks a number of approvals for the cost recovery of the proposed portfolio including: approval of Rider 1 to the ESA, which establishes the customer-specific billing terms and Minimum Monthly Charges ("MMCs") under which the Customer will take service pursuant to the existing Large Load High Load Factor Power Service Rate Schedule ("Rate Schedule LLHLFPS-L"), approval of the Deferral Proposal Framework, authorization of asymmetric depreciation lives for the two generator groups, Fuel Adjustment Clause ("FAC") eligibility for fuel and Long-Term Service Agreement ("LTSA") costs, Formula Rate Plan ("FRP") cost recovery authorization outside the sharing mechanism and caps, and acknowledgment of Sustainability Agreement provisions including the Customer's qualification as a Rider GZ Group 3 subscriber for up to 2,500 MW of designated renewable resources.

Q. Please describe the portfolio of generation, storage, and transmission resources that ELL is proposing.

A. ELL is proposing facilities across three categories: generation, storage, and transmission, with the latter being split into two categories: ELL-funded, and customer-funded transmission. The proposed resources are summarized in the table below.

[Continued to next page.]

Table 1: Proposed portfolio of generation, energy storage, and transmission facilities

		Resource	Technology	Capacity[4]	Target COD[5]		ELL Request	Estimated Capital Cost[6]
Generation		Richland Units 1&2	1x1 CCCT	1,508 MW	Mar-30	1983 General Order	Certification; MBM Order waiver	$3,487M
		Richland Units 3&4		1,508 MW	Oct-30			$3,622M
		Pointe Coupee Units 1&2		1,508 MW	Dec-30			$5,802M
		Pointe Coupee Unit 3		754 MW	Jun-31			
Energy Storage		Bogalusa West BESS	Li-ion , co-located with solar	200 MW / 800 MWh	Dec-28		Certification	$367M
		Cypress Harvest BESS		200 MW / 800 MWh	Oct-28			$367M
		DESRI BESS	Li-ion, standalone	360 MW	TBD			[redacted]
Transmission	ELL funded	WFC–St. Landry 500kV Line (~150 miles)			Dec-31	Transmission Siting Order	Certification	$1,395M[7]
		St. Landry Switching Station (500/230kV)			Dec-31		Exemption	$67M[8]
	Customer funded	Customer-funded 230kV lines (20–30 miles)			Aug-30			[redacted]
		Nine auxiliary 230kV switching stations			Aug-30			[redacted]
		Smalling–El Dorado 500kV Line (~90 miles)			Dec-30			[redacted][9]

Q. What analyses has ELL conducted in support of this Application?

A. ELL presents the direct testimony of fifteen witnesses in support of this Application, covering engineering, gas supply, environmental permitting, financial structure, ratemaking, customer credit risk, accounting, construction execution, and sustainability commitments. Among those, two analyses are central to ELL's public interest case and are the primary focus of my review: a “need analysis” and an “economic analysis.”

Q. Please summarize the need analysis that ELL has conducted in support of this Application.

A. ELL witnesses Beauchamp and Owens present a supply plan analysis according to which they conclude the proposed portfolio of seven CCCTs, three BESS facilities, and

[4] Direct Testimony of Laura K. Beauchamp, HSPM Table 1: Resources in Evest Application, at 4 (“Beauchamp Direct”).

[5] Generation Target Commercial Operation Dates (“CODs”) sourced from: Direct Testimony of Norman Grunden, HSPM Table 2: Key Project Milestones, at 30 (“Grunden Direct”); Transmission CODs sourced from: Direct Testimony of Daniel Kline. Exhibit DK-4 at 3 (“Kline Direct”).

[6] Beauchamp Direct at 90, HSPM Table 9: Capacity Construction Estimates.

[7] *Id.* at 91, HSPM Table 10: Transmission Construction Estimates.

[8] Kline Direct at 31, HSPM Table 1.

[9] Direct Testimony of Thomas Kidd at 5:4-5 (“Kidd Direct”).

associated transmission resources is necessary to serve the Customer's projected load requirements and to meet ELL's capacity obligations. The analysis intends to establish the size, configuration, and timing of the proposed resources based on the Customer's projected demand, load factor, and commercial operation timeline, as well as ELL's MISO Planning Reserve Margin ("PRM") Requirement. Owens further argues that alternative resource types, including renewable and "storage resources, would not be viable stand-alone substitutes for the proposed CCCTs.[10]

Q. Please summarize the economic analysis that ELL has conducted in support of this Application.

A. ELL witness Datta presents a Total Customer Impact ("TCI") analysis intended to quantify the net economic effect of Project Evest on ELL's existing customers over the 20-year Original Term of the ESA. The TCI compares a "Base Case" in which ELL does not serve Project Evest to a "Change Case" in which ELL serves Project Evest and constructs all proposed facilities. According to ELL, the Change Case results in a benefit of approximately [redacted] billion in 2026 dollars, expressed in Net Present Value ("NPV"), compared to the Base Case.[11]

Q. Please summarize the load forecast that is driving the need identified in ELL's Application.

A. The load forecast underlying ELL's Application reflects the projected electricity demand of a single customer, Evest LLC, associated with the hyperscale data center facility to be constructed in Richland Parish, Louisiana. ELL's supply plan is designed to serve the Customer's projected maximum demand of [redacted].[12] These inputs were provided to ELL by the Customer in [redacted] and reflect the Customer's projected operational requirements for the data center facility.[13] The Customer's load will

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[10] Direct Testimony of Nicholas W. Owens at 6:6-17 ("Owens Direct").

[11] Direct Testimony of Samrat Datta at 28 ("Datta Direct"); Direct Testimony of Ryan D. Jones at 5 ("Jones Direct"). References to Mr. Datta's direct testimony include the version as corrected June 10, 2026.

[12] May Direct at 25:21-22.

[13] Beauchamp Direct, Exhibit LKB-9 at 1, n.1 ("Customer Ramp based on info provided to ELL on [redacted]").

not reach its full contracted level immediately upon the commencement of service. ELL's supply plan incorporates a ramp schedule under which the Customer's load increases over time as the data center facility is constructed and brought into operation. Construction power (electrical service to the construction site during the physical build-out of the facility) is expected to begin in [redacted] [redacted].[14] Commissioning power (service to support testing and startup of data center equipment before commercial operation) is expected to begin in approximately [redacted] Customer load increases through September 2031, when it is expected to reach the full contracted demand of [redacted].[15] During the bridge period before all CCCTs are in service, [redacted].[16]

Figure 1: Customer Load Ramp[17] (HSPM / AEO)

[redacted]

[14] Beauchamp Direct at 43:6-9.

[15] Beauchamp Direct at 7:14, 38:5, 79:6, 104:14.

[16] Beauchamp Direct at 6:15-7:3.

[17] *See* ELL response to data request Staff 1-1, Exhibit RDJ-2 Rate Analysis Model_AEO, "Ramp-Up Schedule" tab (AEO).

Q. What cost recovery mechanisms does ELL propose for the construction and continued operation of the proposed facilities?

A. ELL proposes different cost recovery mechanisms depending on the resource type. I address each in turn.

- ***CCCTs**:*

Capital Costs: ELL requests FRP recovery of the revenue requirements associated with the Proposed Generators beginning in the first billing cycle following each unit's commercial operation date.[18] ELL further requests that this recovery occur outside the FRP sharing mechanism and outside any applicable FRP caps, offset by deferred Customer revenues under the Deferral Proposal Framework. The Customer funds the capital program through two mechanisms: an upfront Contribution in Aid of Construction and Capital Costs ("CIAC") payment of approximately [redacted],[19] which offsets the carrying charges ELL incurs during the construction period, before the CCCTs enter service and begin generating revenue from the Customer's Monthly Minimum Charges ("MMCs"). According to ELL, the MMCs are sized to recover the full non-fuel revenue requirement of the Proposed Generators, including capital recovery, return on rate base, fixed O&M, taxes, and insurance, over the 20-year Original Term of the ESA, but do not include fuel costs (variable and fixed), LTSA costs, or other variable operating costs, which are recovered separately through the FAC.[20] ELL is proposing to depreciate the Richland units over 20 years and the Pointe Coupee units over 32 years.[21]

Fuel and variable operating costs: Based on ELL's requested classification as system resources, ELL requests FAC recovery of fuel costs, including firm transportation costs,[22] for the Proposed Generators. ELL also requests FAC recovery of LTSA costs for major scheduled maintenance of the CCCTs. LTSA costs are variable, based on starts and

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[18] Application at 32, Prayer for Relief 13 at 32-33.

[19] Kidd Direct at 6:22.

[20] Jones Direct at 38:12-14, 41:19-23.

[21] Application at 33, Prayer for Relief 15 at 33.

[22] ELL response to data request AAE 1-4(g).

accumulated operating hours, and are estimated at approximately $8.7 million per unit per year in the first year of operation, increasing to approximately $10.3 million per unit per year on average with escalation over the contract term.[23]

- ***BESS facilities***:

  Capital costs: ELL requests the same FRP recovery treatment for the three BESS facilities as with the CCCTs: recovery upon commercial operation, outside the FRP sharing mechanism and caps, offset by deferred Customer revenues. The BESS capital costs are recovered through MMCs over the Original Term, but no upfront CIAC payment applies to these facilities.

  Energy charging costs: ELL requests FAC recovery of the costs of energy used to charge the BESS facilities from the grid, based on their classification as system resources.

- ***ELL-funded transmission*** (WFC–St. Landry 500kV Line and St. Landry Switching Station):

  Capital costs: ELL requests FRP recovery of the revenue requirements associated with these facilities, net of offsetting Customer revenues.

- ***Customer-funded transmission*** (230kV interconnection lines, nine auxiliary 230kV switching stations, and Smalling–El Dorado 500kV Line):

  Capital costs: Fully funded through the CIAC. Thus, ELL requests no rate recovery mechanism for these facilities.

Table 2: Cost Recovery of proposed facilities

Resource	Cost Component	Recovery Mechanism	Amount / Rate
CCCTs	Capital costs	CIAC & Rates & MMCs	$12.911B[24]
	Fuel costs	FAC	[redacted][25]

[23] Grunden Direct at 36:4.

[24] Grunden Direct at 19:9.

[25] Datta Direct, Exhibit SD-2, at 3, Row "Average Evest LLC Fuel Cost [$/MWh]" (HSPM).

	LTSA	FAC	~$10.3M/unit/yr (avg)[26]
BESS	Capital costs	Rates & MMCs	[redacted][27]
	Energy charging costs	FAC	Variable[28]
ELL-Funded Transmission	Capital costs	Rates & MMCs	$1,462M[29]
Customer-Funded Transmission	Capital costs	CIAC	[redacted][30]

IV. ELL'S PROPOSAL EXPOSES EXISTING CUSTOMERS TO SUBSTANTIAL COST RISK

A. Net benefits claimed by ELL are modest in proportion to overall scale of investment

Q. You stated that the Total Customer Impact (or "TCI") analysis is central to ELL's public interest case. What is your overall assessment of the TCI?

A. ELL's calculation of the TCI shows an NPV benefit of approximately $1.968 billion in 2026 dollars.[31] The estimated net benefits drop to $991[32] million in the non-renewal scenario, in which the Customer does not renew the ESA beyond the 20-year original term.[33] Both figures appear significant in absolute terms but need to be evaluated within the context of the cost commitment underlying them. The total costs flowing through the

[26] Grunden Direct at 36:4.

[27] Beauchamp Direct at 90, HSPM Table 9 (Self-build Storage $734M + Procured Storage [redacted] = [redacted]).

[28] Jones Direct at 41:21-23.

[29] Kline Direct at 31, HSPM/AEO Table 1.

[30] Kidd Direct at 5:5.

[31] Datta Direct at 29.

[32] *Id.* at 32. On June 10, 2026, ELL filed errata identifying three errors in the TCI analysis (Exhibit SD-2 (HSPM/AEO)), along with a correction to certain pages of witness Datta's testimony. The three errors include the base case row, the 2028 amounts for the customer funded programs, and a minor issue in the capacity surplus/deficit calculation. The corrected testimonies and exhibit SD-2 result in the $991 million TCI estimate (Ex. SD-2 (Corrected) at 3). ELL also provided an updated spreadsheet for this exhibit "Staff 1-1 HSPM Exhibit SD-2 Errata_AEO" (HSPM/AEO) that [redacted] TCI estimate. All estimates presented in my testimony are derived from this spreadsheet after having [redacted] to match the PDF version of the exhibit. [redacted] based on the PDF version.

[33] Notably the ESA renewal term is not specified in ELL's analysis, but the Company assumes that all residual costs will be absorbed by the Customer (whereas general ratepayers absorb residual plant costs in the "non-renewal" scenario). Datta Direct at 30:5-13.

model are approximately $28.5 billion ("NPV").[34] The net benefit is what remains after subtracting those costs from approximately $30.4 billion in gross benefits.[35] This indicates a benefit margin to ratepayers of roughly 6.5% in the case the Customer renews and 3.5% in the case of non-renewal. Thus, a change of corresponding magnitude (*e.g.*, 3.5% increase in costs, or 3.5% decrease in revenue) could reduce or eliminate the net benefit or even convert the impact into a net cost to existing customers. Given the significant uncertainty that characterizes both the projected revenues, as well as the projected costs, a deviation from projections that could leave existing ratepayers worse off is a very plausible scenario. Meanwhile, as I will explain more fully in Section V of my testimony, the terms of the ESA do not sufficiently protect existing customers from such a scenario.

Q. Are there any recent examples of ELL plant costs being higher than expected?

A. Yes. A recent quarterly monitoring report from LPSC Docket No. U-37425 showed that projected capital costs for the Laidley Generation and Transmission projects are now $465 million (about 11.7%) more expensive than expected.[36]

Q. What are the benefits that ELL witness Datta includes in the TCI analysis?

A. The benefits included in Table 1 of the direct testimony of ELL witness Datta, as corrected by the June 10, 2026 errata, total approximately $30.4 billion NPV in 2026 dollars. The table below summarizes each line item and its share of total gross benefits.

[Continued to next page.]

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[34] Datta Direct at 29, Table 1 (HSPM / AEO).

[35] Id.

[36] Docket No. U-37425, Laidley Generation and Transmission Project Quarterly Monitoring Report, at 4 (May 15, 2026) (comparing updated Class 3 estimate of $4,421 million to $3,956 million as originally estimated).

Table 3: Benefits and Costs in ELL's TCI Analysis (Non-Renewal Scenario) (HSPM / AEO)

Total Customer Impact - Benefit/(Cost)	**NPV 2026$ in million $991.33**	
Benefits	**PV 2026$ in million**	**Share of Benefits**
Evest LLC (ESA) Revenue	[redacted]	
Resilience Plan Recovery Charge	[redacted]	
Financed Storm Cost Riders	[redacted]	
Storm Cost Offset Riders	[redacted]	
Power to Care - Customer Commitments	[redacted]	
Energy Efficiency - Customer Commitments	[redacted]	
Evest LLC Fuel Revenue (Firm)	[redacted]	
Evest LLC Ramp Fuel Revenue (Non-Firm) - LMP	[redacted]	
Total Laidley LLC Fuel Burden	[redacted]	
Evest LLC + Laidley LLC - Recovered Fixed Fuel Demand - Evest LLC Resources	[redacted]	
Evest LLC Only - Recovered Fixed Fuel Demand - Rest of Fleet	[redacted]	
Capacity Benefit/(Cost)	[redacted]	
Total Benefit	$ 30,419	100%
Costs	**PV 2026$ in million**	**Share of Costs**
Evest LLC Variable Supply Cost	[redacted]	
Gas Generation Revenue Requirement	[redacted]	
Gas Generation Fixed and Variable O&M	[redacted]	
Battery Costs	[redacted]	
Transmission Revenue Requirement	[redacted]	
Other Incremental O&M	[redacted]	
Credit Insurance Premiums	[redacted]	
Return on Deferred Revenue Liability	[redacted]	
Richland 1 (3/30/2030)	[redacted]	
Richland 2 (3/30/2030)	[redacted]	
Richland 3 (10/31/2030)	[redacted]	
Richland 4 (10/31/2030)	[redacted]	
Point Coupee 1 (12/31/2030)	[redacted]	
Point Coupee 2 (12/31/2030)	[redacted]	
Point Coupee 3 (6/30/2031)	[redacted]	
Total Residual Rate Base	[redacted]	
Total Costs	**$ 29,428**	**100%**

It is worth noting that two line items, the "ESA Revenue" and the "Fuel Revenue (Firm)," account for $[redacted] billion, or approximately [redacted] of total gross benefits.[37] Both depend on the Customer taking service at the projected maximum demand and load factor for the full 20-year Original Term. No other benefit line item is large enough to compensate if either of those two assumptions proves incorrect. On the cost side, the Variable Supply Cost and the Gas Generation Revenue Requirement collectively account for [redacted]% of the total costs, and while the former is a variable cost that is the function of the Customer's actual energy use, the latter is a fixed cost that will be incurred independently of whether load materializes at the projected scale and pace.

Q. Do the $1.968 billion or $991 million net benefit figures fully capture the risks associated with the significant underlying capital investment?

A. No. These figures reflect an optimistic case in which all future costs and benefits follow ELL's current projections until 2048. However, to better understand some of the risks to which existing ratepayers will be exposed to under ELL's proposal, it is necessary to evaluate the range of outcomes that could arise if ELL's assumptions prove incorrect. Several downside scenarios are plausible over a 20-year commitment of this scale, including but not limited to: demand [redacted], a lower-than-projected load factor, capital cost overruns, or early termination. Any combination of these could produce an economic loss to existing ratepayers measured in billions of dollars.

B. No sensitivity analysis was performed on key variables with substantial uncertainty

Q. Did ELL conduct sensitivity analyses on the key cost and revenue assumptions underlying the TCIs?

A. Not based on what I have reviewed in ELL's Application and workpapers. ELL did not appear to consider any scenarios where key assumptions were differed in plausible ways. In this subsection I will address ELL's failure to address several of these key assumptions

[37] Datta Direct Testimony at 29, HSPM/AEO Table 1, as corrected by the June 10, 2026 errata.

including: 1) lower load materialization, 2) capital cost overrun scenarios, 3) fuel-related cost assumptions, and 4) other assumptions (*e.g.*, carbon policy, capacity position). Consequently, the TCI is a single-point estimate under a single set of assumptions that may not be robust across a range of scenarios. The lack of any sensitivity analysis to test for robustness over a 20-year horizon constitutes an unreasonable and imprudent approach to planning given the sheer scale of the investment at stake.

As an illustrative example, the ESA Revenue line is the largest single benefit component in the TCI model at approximately $[redacted] billion NPV. A [redacted]% reduction in the projected ESA revenues from the corrected figure would eliminate the estimated net benefit entirely. That figure was itself the subject of the errata filed June 10, 2026. The original filing contained a formula error in the Base Case row of the SD-2 workbook: a cell reference that pulled from the wrong row in Exhibit RDJ-2, estimating benefits based on "Test Year Revenue Requirement (incl return on reg liability)" rather than the corrected "Test Year Revenue." That single correction resulted in an approximately 100% change in the net benefit, demonstrating how sensitive the TCI calculation is to a single input assumption spreadsheet error.

Q. Did you conduct any of your own analysis to understand the risk exposure for existing ratepayers?

A. Yes, to the extent I was able to, given the limited time and resources I had available. I reviewed ELL's rate and TCI analysis to evaluate the sensitivity of the projected net benefit to changes in key assumptions. I did not attempt to replicate ELL's full analysis, partly due to data limitations (for example, several ELL workpapers that were produced in discovery contained non-transparent hardcoded values instead of supporting calculations), and partly because some of the inputs to the TCI were the results of AURORA modeling. However, the analysis I did perform still allowed me to draw meaningful conclusions by contextualizing the TCI results against plausible changes in some key assumptions, starting with the ESA revenue and the revenue requirement of the proposed portfolio. I present some illustrative results below.

1. Load Materialization

Q. Did ELL explain the lack of a sensitivity analysis to evaluate the risk of the Customer's load being lower than projected?

A. No. In response to a discovery question, which asked whether ELL had conducted sensitivity analyses showing the impact on the TCI of load materializing below the projected maximum demand or load factor and asking ELL to identify the load level at which the TCI would become negative, ELL responded that no such analysis had been performed.[38] Rather, ELL stated that the metered kWh assumption used in the rate analysis, which informed the TCI analysis, is based on the best information received from the Customer, and that the Company remains confident in that assumption. Thus, ELL only conducted a single analysis which assumes that the load materializes as expected both in terms of its peak demand (MW), as well as in terms of the energy required (MWh).

Q. Is it reasonable for ELL to use a single self-reported load projection from the Customer as the sole basis for the TCI that supports an application of this size?

A. No. Using the Customer's projection as a starting point is reasonable. My concern is not that ELL relied on it for the base case, but that it relied on it exclusively, without testing the consequences if it proves incorrect. This is particularly concerning given the uncertainty surrounding hyperscale data center demand over a 20-year horizon. The technology driving this investment has not existed long enough to support confident projections over that timeframe. Over a 20-year period, data center infrastructure requirements could evolve, GPU power use efficiency could improve, business plans could change, and the Customer's actual load profile could change from what is projected today. Any one of those developments could result in the Customer operating at a lower load factor, [redacted], or reassessing its long-term commitment to the facility. A [redacted]% load factor is very high for any load, leaving no room for upside in the

[38] ELL response to data request NPO 5-5. ELL captioned its responses to the NPO Third Set through Ninth Set of Data Requests as beginning with "AAE."

analysis but resulting in significant downside exposure if actual operations fall short of that level. A sensitivity analysis exploring those scenarios is the bare minimum that prudent planning requires. Without it, the Commission has no quantitative basis for evaluating the range of outcomes ratepayers could face if the Customer-reported load projection proves incorrect.

Q. Did you perform an analysis to assess the sensitivity of ELL's TCI analysis (*i.e.*, net benefits analysis) to load materialization assumptions?

A. Yes. Importantly, through this analysis I determined that the demand and energy levels assumed by ELL in its TCI analysis result in revenues that [redacted].[39] [redacted]. Conversely, if the load does not fully materialize as expected and the Customer pays only the MMCs, the expected benefits would drop significantly. There are several ways the load could fail to reach the minimum threshold, including: 1) because the peak demand is slower to fully materialize, 2) because the load never reaches its contracted level, or 3) because the peak demand materializes but the load factor falls below the projected [redacted]%.

Q. If the load does not reach the minimum thresholds contemplated in the contract, what would be the impact on the TCI?

A. Based on my recalculation of ELL's rate analysis model (as included in the RDJ-2 exhibit), if the projected demand and load factor each decreased by 10 percent, the resulting NPV of base rate revenues would fall by approximately $[redacted], flowing directly through to the net benefit. If both assumptions decline simultaneously by approximately [redacted]. While actual fuel costs would also decrease with lower consumption, the net impact would be an overall reduction in the net benefits to other customers. Additionally, as I discuss in Section IV.B.3, fixed fuel demand charges do

[39] *See* ELL response to data request Staff 1-1, Exhibit RDJ-2 Rate Analysis Model_AEO (HSPM / AEO), "Rate Revenues - Omega" tab, rows 20 and 22 (base rate revenues at customer-reported billing determinants exceed the corresponding MMCs).

not scale with load: the Customer's load-ratio share of those charges would fall while the charges themselves remain unchanged, shifting a greater portion to existing ratepayers and producing a further reduction in net benefits beyond the base rate shortfall alone.

2. Capital Costs

Q. What does your analysis show about the sensitivity of the TCI to capital costs?

A. The second largest component in ELL's net benefit estimate is the projected gas generation revenue requirement. An increase of [redacted]% in that revenue requirement would eliminate the net benefit in the non-renewal case.

Q. Is an increase in the gas generation revenue requirement of greater than [redacted]% a plausible scenario?

A. Yes. By ELL's own classification, the cost estimates for five of the seven CCCTs are priced on Class 4 estimates, and the ELL-funded transmission is priced on Class 5 estimates,[40] rendering a deviation of this magnitude plausible, if not likely. Exhibit LKB-5 describes a Class 5 estimate as [redacted].[41] The same exhibit also notes that even a Class 3 Facilities Study, a more definitive estimate which is the highest given to any of the proposed CCCTs (two of seven units), [redacted]. By contrast, ELL's contingency allowance is approximately 5% of total project costs.[43]

Q. Have you quantified what cost overruns of these magnitudes would mean for the TCI?

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[40] Grunden Direct at 20, HSPM Table 1; Kline Direct at 31:15-17.

[41] Beauchamp Direct, Exhibit LKB-5 (HSPM / AEO) at 9-10; *see also* Kline Direct at 32:22-23 (Class 5 estimates are "by definition, high level and preliminary").

[42] Beauchamp Direct, Exhibit LKB-5 (HSPM / AEO) at 9-10.

[43] Grunden Direct at 24:20-22.

A. Yes. Using Exhibit SD-2 (HSPM/AEO), I calculated the effect of proportional increases in the committed, fixed cost items of the proposal that are independent of load. These include: the gas generation revenue requirement, gas generation Fixed and Variable O&M, battery costs, transmission revenue requirement, and fixed fuel demand charges, which together total approximately [redacted] NPV as the committed costs of constructing and operating the proposed portfolio.[44] I then calculated the effect of these costs escalating above ELL's estimates:

Table 4: Net benefits under different capital cost overrun scenarios (HSPM / AEO)

Overrun	**Reduction in TCI net benefit**	**Resulting net benefit (full 20-year term + renewal, NPV 2026$)**	**Resulting net benefit (Non-Renewal Case, NPV 2026$)**
+5%	[redacted]	[redacted]	[redacted]
[redacted]% (breakeven, non-renewal)	[redacted]	[redacted]	[redacted]
+10%	[redacted]	[redacted]	[redacted]
[redacted]% (breakeven, renewal)	[redacted]	[redacted]	[redacted]
+20%	[redacted]	[redacted]	[redacted]
+30% (Class 3 range)	[redacted]	[redacted]	[redacted]

A cost increase of approximately [redacted]% is sufficient on its own to eliminate the entire projected net benefit in the non-renewal case. That threshold sits within the tolerance of the estimates on which this portfolio is priced. At [redacted]%, existing ratepayers are worse off by more than $[redacted].

Q. ELL points to the fixed-price engineering, procurement, and construction ("EPC") contract and the MMC true-up as protection against cost overruns. Do those mitigate this risk?

A. Only partially. The EPC contract general terms and conditions reflected in Exhibit NG-1 provide for a fixed price and a fixed schedule, and the final true-up passes prudently

[44] The Proposed Generators alone have an estimated capital cost of $13 billion. May Direct at 33:22-23.

incurred actual costs through to the Customer's MMCs.[45] But certain cost exposures could survive those protections. For example, timing: the final true-up is not projected to occur until approximately 2035,[46] and in the interim any overrun could be passed through to customer rates. Additionally, there is potential for contingent events, like if the Customer exits or [redacted] before the true-up occurs, in which case the higher revenue requirement due to the overrun might never be fully recovered from the Customer and could fall to other customers (*e.g.*, if ELL requests Retained Generator status upon termination).

While the protections narrow the exposure, they do not entirely eliminate it, and the TCI remains a single-point estimate with less margin for error than the accuracy range of the estimates it is built on.

Q. Even if the true-up functions as intended and the Customer bears the full prudently incurred cost of any overrun, does that fully resolve your concern?

A. No. The true-up addresses who pays for an overrun during the Original Term; it does not address whether the portfolio was the right investment in the first place. If the proposed resources are built at a cost materially above ELL's estimates, the result is a portfolio that is more expensive than what the Commission was asked to approve, and potentially more expensive than alternatives that were not fully evaluated. The true-up may shift the incremental cost to the Customer for the years the Customer takes service, but it does not make the underlying asset any cheaper, and it does not eliminate the cost to existing ratepayers over the life of the assets. Existing customers retain exposure to these resources well beyond the Original Term: [redacted] in residual net plant remains in rate base at the end of the term, and if the Customer does not renew, or if ELL elects Retained Generator status upon an earlier termination, existing ratepayers become responsible for a resource that was constructed to serve a single customer.

[45] Jones Direct at 35:1-36:20.

[46] *Id.* at 36:11-15.

3. Fuel-related Costs

Q. Do you have concerns about the way fuel costs have been included in ELL's TCI analysis?

A. Yes. There are two types of incremental fuel-related costs that could ultimately shift a greater portion of costs to existing customers under ELL's proposal: fixed fuel costs and variable fuel costs. While I have concerns about both, my larger concern relates to the fixed fuel component, primarily comprised of firm transportation costs.

Q. Please elaborate on your concerns around the firm transportation costs.

A. Most fuel costs are variable, meaning that if the Customer's load decreases, fuel consumption decreases proportionately, and FAC costs fall accordingly. In contrast, firm transportation costs (*e.g.*, fixed pipeline reservation charges) are generally fixed costs that do not scale with actual consumption. Thus, a unit operating at 70% of its projected capacity factor still results in the same fixed reservation charge as one operating at 90%.

The TCI includes a "Recovered Fixed Fuel Demand" benefit of approximately $[redacted] million NPV. Meanwhile, ELL's analysis also includes firm transportation costs for each individual generating unit, totaling $[redacted] million NPV when summed across all seven CC units.

That benefit depends on the Customer taking service at the projected load level. If, however, the Customer's actual load is lower than projected, its load-ratio share decreases and its revenue contribution in this category falls proportionately. The firm transportation cost component, however, would not fall, resulting in a reduction of the TCI benefits. Essentially, the shortfall shifts the fixed FT costs to existing ratepayers through the FAC.

Q. Did ELL confirm that fixed fuel demand costs will be passed through the FAC?

A. Yes. This was confirmed in discovery.[47] In this response, ELL suggested that some of these fixed fuel costs might be offset through margins on wholesale energy sales.

[47] ELL response to data request Staff 1-17(a).

However, ELL's response did not articulate any limitations on the amount of fixed fuel costs that it would seek to recover through the FAC. Thus, all ELL retail customers who pay the FAC charges are still exposed to the full amount of these incremental fixed fuel costs.

Q. Are the firm gas transportation costs assumed in ELL's analysis equal to incremental costs that the Company will actually incur for the additional fixed fuel demand (*e.g.*, pipeline upgrades)?

A. Not necessarily. The costs assumed are estimated payments,[48] rather than specific incremental costs for pipeline projects or contracts being reviewed by the Commission. Thus, the actual costs incurred could differ substantially from these estimates.

Q. Are these firm transportation costs subject to the same customer protections included in the ESA for fixed generation costs?

A. No. My understanding is that these firm transportation costs are not specifically identified or robustly addressed in the terms of the ESA. Thus, any true-up of the MMC to account for cost overruns of fixed generation would not apply equally to fixed fuel costs. Additionally, any termination provisions intended to protect existing customers from unrecouped power generation costs would not apply to the unrecouped fixed fuel demand costs expected over the remaining life of the ESA term.

Q. Absent any cost overruns or termination trigger events, would existing customers still be subject to higher fixed fuel costs under ELL's proposal?

A. Yes. As I explained above, it does not appear that the fixed fuel demand costs charged to the Customer will represent the full incremental or marginal costs incurred to provide firm transportation to the Proposed Generators. As such, some portion of those marginal costs will be shifted to existing customers. This is because ELL requests that the Proposed Generators are treated as system resources, meaning that the Customer will pay

[48] ELL responses to data request Staff 1-17 and Staff 1-34.

the *average* cost of fuel supply (including firm transportation) across ELL's entire fleet rather than the *marginal* cost of the fuel supply and incremental new pipeline infrastructure specifically required to serve the Customer's load. The marginal cost of new firm transportation for the Proposed Generators is likely to be higher than ELL's existing fleetwide average -- particularly for Pointe Coupee Units 1–3 which ELL confirmed will likely require a new greenfield or brownfield pipeline.[49] By allocating costs for the new pipelines serving the Proposed Generators on a system average basis, ELL's proposal effectively means that these new pipeline costs are being subsidized by existing customers. As stated earlier, under ELL's TCI analysis, the "Recovered Fixed Fuel Demand" benefit is approximately $[redacted] NPV, while the cost is [redacted] NPV when summed across all seven CC units. The assumption behind the firm transportation cost is [redacted]/MMBtu/year and $[redacted]/MMBtu/year for the Richland and Pointe Coupee units, respectively.[50] If those estimates were to increase by 20 percent, a plausible increase given the increasing demand and limited options, the costs would increase to [redacted] NPV, while the revenues would only increase to [redacted] [redacted] NPV, due to shifting some of the costs to existing ratepayers. The TCI would, consequently, be reduced by [redacted] NPV.

4. Other Assumptions (carbon risk, capacity position)

i. Carbon Policy

Q. Please elaborate on your concern regarding carbon policy risk.

A. The TCI analysis includes no carbon price assumption, which is reasonable for the base case given current policy. However, the proposed CCCTs have an expected operating life extending to at least 2048 and potentially beyond. Over a horizon of that length, it is plausible that some form of carbon pricing or regulation will be implemented (whether through EPA rulemaking, federal legislation, or state policy).

[49] Direct Testimony of Michael J. Goin at 11:9-12 ("Goin Direct").

[50] *See* ELL response to data request Staff 1-1, HSPM Exhibit SD-2 Errata_AEO, "Data Library" tab.

According to ELL, potential compliance with the EPA rules if they were implemented would include the application of Carbon Capture and Sequestration ("CCS"). ELL's witness Halland acknowledges that while CCS technology is technically available, no project has yet successfully implemented CCS on a natural gas-fired CCCT in the United States, and that project economics are typically what makes CCS not feasible.[51] The CCCTs operating continuously at a high load factor would therefore face material compliance costs under such a scenario that are not reflected in ELL's current analysis and for which no cost estimate or funding mechanism exists in the record. My understanding is also that this risk is not hedged through any ESA provision. Project Evest, by adding seven large CCCTs to ELL's fleet, increases ELL's overall carbon exposure without any mechanism to share that exposure with the Customer over the life of the ESA.

ii. Capacity Position

Q. Are there other assumptions that if changed, could have a significant impact on the net benefits estimate?

A. Yes. My analysis was not exhaustive. Other assumptions that could materially affect the net benefit estimate include parameters associated with the cost recovery structure, the discount rate, market assumptions, and others. One worth noting specifically is the capacity value ELL assigns to the proposed portfolio. The Capacity Benefit/(Cost) line in Datta's model is intended to capture the incremental cost or benefit to the system resulting from the addition of the Customer's load and the proposed facilities, specifically whether the system ends up with a capacity shortage or a capacity surplus after those additions, and what that shortage or surplus is worth. That line currently stands at approximately [redacted] NPV,[52] reflecting a net capacity cost driven by a capacity shortfall during the bridge period when the Customer's load exceeds ELL's firm load-serving capability before all CCCTs are in service. After 2031, the model shows a

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[51] Direct Testimony of Jeremy Halland at 7:15-19 ("Halland Direct").

[52] Datta Direct at 29, Table 1 (HSPM/AEO).

capacity surplus. Both the capacity deficit and the surplus are included in the TCI based on the levelized cost of a Combustion Turbine,[53] reflecting the marginal cost or benefit of the deficit/surplus in ELL's system. I agree that in the near term, a capacity deficit represents a real, measurable cost. However, a capacity surplus in the longer term does not automatically generate a benefit of equivalent value.

ELL claims that surplus generating capacity benefits existing customers because it could either be sold into the market or used to displace future resource additions.[54] However, that argument assumes the surplus capacity has market value in later years when uncertainty is significantly greater than the near term. If datacenter infrastructure and corresponding electric demand across the region proves lower than currently projected, ELL and other utilities in MISO could just as easily hold surplus capacity. In that environment, the surplus capacity credited as a benefit in the TCI model may clear at low or zero value rather than at the avoided CT cost ELL assumes.

If the capacity surplus is valued at zero rather than at the avoided CT cost assumed in the TCI model, the net benefit declines from approximately [redacted] in the non-renewal scenario to approximately [redacted]

5. Compound impacts of changes to key assumptions

Q. Each of the items you presented reduces the TCI benefits by some amount but none reduces them completely. Do you have any thoughts on this?

A. Each of the items I have described (*i.e.*, a reduction in revenues, a capital cost overruns, fuel cost exposure, the potential escalation of fixed transportation charges, the existence of carbon policy risk, the uncertainty of the capacity surplus valuation) represents a plausible reduction to the projected net benefit when considered in isolation. But none of them are mutually exclusive or would necessarily occur in isolation. In fact, some may be correlated. For example, a Customer operating at a lower load factor pays less into the

[53] Datta Direct at 21:5-14.

[54] See ELL responses to data requests NPO 3-18 and NPO 3-19.

FAC, reducing the fuel revenue benefit, while the fixed transportation charges remain unchanged and shift to existing ratepayers. In that same scenario, surplus capacity in MISO may clear at depressed prices. Assumptions that unfold differently than projected in ELL's TCI analysis can compound one other, moving the results quickly from a reduced net benefit to a net loss, even if Evest pays Minimum Monthly Charges for the full 20 years of the contract.

As explained earlier, the net benefit in the base case is only 3.5% of the costs over a 20-year period. This was determined from a single scenario with no sensitivity testing. Thus, when a broader range of scenarios is considered, the magnitude of savings does not appear to be very robust for an investment of this scale.

C. Net Benefits for most customers (*i.e.*, residential) are highly dependent on how revenue is allocated between customer classes

Q. Will the net revenues collected from the MMC provide a direct benefit to existing residential customers?

A. Not necessarily. The degree to which ELL's proposal provides a benefit to residential customers depends largely on how costs and revenues are allocated between customer classes. Under most normal circumstances, utilities will allocate fixed generation capacity costs proportionally among all customer classes using the preferred or authorized method for cost allocation. However, the revenues collected from the Customer could be retained within the large industrial customer class that includes the LLHLFPS-L Rate Schedule. This has the potential to create a mismatch between the allocation of incremental costs and incremental revenues.

Q. Does ELL's application describe how incremental costs will be allocated?

A. Not with sufficient detail to understand potential impacts among all customer classes. Specifically, ELL confirmed that generation costs would be allocated to all customer classes as system resources and that fuel costs would be recoverable from all customers through the FAC, consistent with ELL's proposed treatment of the assets as system resources. However, ELL has not conducted a cost-of-service study or rate impact analysis to quantify the impact on individual customer classes or the average residential customer.[55]

Q. Does ELL's application describe how incremental revenues will be allocated?

A. Not specifically.

Q. Did ELL provide any further clarification on this matter when asked through discovery?

A. Partially. In response to a discovery request, ELL stated that "Evest-associated revenue will be used to offset the rate effects of the incremental revenue requirements in and through the same mechanisms through which the cost of the investment is eligible to be recovered" and that "Excess revenue from Evest… will be included in annual Formula Rate Plan Evaluation Reports as FRP Revenues that … are allocated as a percentage of Base Rate Revenue for all eligible retail rate classes."[56] However, this response does not define "all eligible rate classes" nor does it provide exact detail on what allocators will be used to apportion the revenues accordingly to each rate class.

Q. What do you conclude from this?

A. Even if ELL estimates that customers as a whole will receive net benefits from the Company's proposal, those benefits are not guaranteed to materialize for residential customers and instead could be concentrated within the industrial customer class. This will also depend on ELL's approach to future allocation of the incremental costs and revenues, which are still to be determined.

Q. What do you recommend to address these concerns regarding cost allocation?

A. If the Commission approves ELL's request, it should require that the Company also update its approach to cost allocation to ensure that residential customers are not unfairly burdened. Specifically, the incremental net revenues generated from the Customer (*i.e.*,

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[55] ELL response to data request SREA 1-2(a).

[56] ELL response to data request NPO 7-2.

revenues in excess of costs) should be shared across all customer classes. The method for allocating these revenues among customer classes should be based on a recent historic retail sales year (*e.g.*, from year 2025) that predates the ESA to ensure that existing customers benefit from bearing significant additional risk for the proposed investments. While this approach is necessary to avoid inappropriate cost shifting, it is not clear from ELL's proposal that this will occur naturally and may require broader revisions to ELL's retail rate structures.

Q. Please elaborate on your concern about sharing of revenues across customer classes.

A. I am concerned that the revenue collected from the Customer in this case will remain allocated predominately within the High Load LLHLFPS-L customer class. Notably, another significant Meta-owned data center customer (the Laidley facility) is within this customer class. Thus, Meta itself could be the primary beneficiary of the revenue collected from the Customer unless a broader revenue apportionment scheme is considered.

D. ELL's request includes waivers or suspensions of rules designed to provide customer protections

B. **Do you have other concerns you would like to raise as the Commission considers this application?**

A. Yes. ELL's application seeks waivers of two regulatory frameworks specifically designed to protect customers: the MBM Order and the FRP sharing mechanism.[57] Each request removes a protection that existing rules provide to ratepayers.

ELL is proposing approximately $15.8 billion in new generation, storage, and transmission resources, a scale of investment that, to my knowledge, has no precedent in ELL's regulatory history. The cost recovery and competitive solicitation protections ELL seeks to waive exist precisely to protect ratepayers in circumstances like these – *i.e.*, to

[57] Application at 23-24 and Prayer for Relief 5 at 28; Prayer for Relief 13 at 32-33.

minimize the costs of large generation investments. In this section, I focus on the requested MBM waiver.

Q. What is the MBM Order and why is ELL seeking a waiver?

A. The MBM Order, as amended by General Order No. 10-14-2024, requires ELL to employ a market-based mechanism before self-building generating capacity to serve LPSC-jurisdictional retail customers.[58] That mechanism must be an RFP competitive solicitation process "constructed as broadly as possible to allow for review of all available options to add generating capacity," which must include the solicitation and evaluation of power purchase agreements ("PPAs") and "all available market options, including, but not limited to conventional resources, intermittent resources, hybrid resources, and storage."[59] The 2024 Order adds that in no event shall a proposed alternative mechanism be limited to self-build or utility-owned resources. The Order also requires ELL to identify and retain an independent monitor to review ELL's conduct of the RFP and submit a final evaluation report to the Commission.

ELL is requesting a waiver of the entire MBM process under the Lightning Initiative, which allows the Commission to waive the competitive solicitation requirements where a signed ESA with a new or expanding load has a requested in-service date within five years, ELL would otherwise be energy- or capacity-short, Louisiana Economic Development confirms the customer's interest, the ESA term is at least fifteen years with a renewal option, and fixed revenue covers at least half the associated capacity's fixed revenue requirement during the contract term.[60] Alternatively, ELL requests a good-cause exemption.[61]

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[58] General Order No. 10-14-2024 (R-34247), In re: Rulemaking to consider changes to Commission General Order dated October 29, 2008 (Docket No. R-26172 Subdocket C) ("Market Based Mechanisms Order") to incorporate formal complaint procedures, ("MBM Order"), Attachment A, Rule 1, Louisiana Public Service Commission (Oct. 14, 2024), https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/ViewFile?fileId=ZsHaodDYfhA%3D at PDF p. 20.

[59] MBM Order, Attachment A, Rule 3 (*id*.).

[60] LPSC, Lightning Amendment to General Order 10-14-2024 (*see* Minutes of December 17, 2025 Open Meeting, at 6-7, https://lpsc.louisiana.gov/docs/minutes/Dec_17_2025_Min.pdf).

[61] Application at 23-24 and Prayer for Relief 5 at 28; *see also* Jones Direct at 54-56.

Q. Does ELL's request to waive the MBM Order raise concerns for existing ratepayers?

A. Yes. ELL did not conduct a competitive solicitation for supply resources,[62] did not evaluate PPAs or renewable alternatives against its self-build proposal,[63] and did not engage an independent monitor.[64] Even putting aside the load materialization risk I discuss throughout my testimony, I am concerned that these omissions have resulted in a proposal that has not been tested against the market and may not represent "the provision of reliable electric service at the lowest reasonable cost." [65]

Q. What is your overall assessment of ELL's request to waive the MBM Order under the Lightning Initiative?

A. As I discussed earlier in my testimony, the projected net benefits are narrow (approximately [redacted] in the non-renewal scenario) and may not be clear or persistent across alternative scenarios that ELL did not explore.[66] Furthermore, as I discuss in Section VII, while the need for Richland Unit 1 may be urgent, the need for the remaining proposed units is not urgent. The Lightning Initiative's criteria are, as ELL's own witness describes them, "in the nature of protections for other utility customers," and they include a requirement that, without the proposed capacity addition, the applicant be projected to be short of the energy or capacity needed to meet the customer's requirements on the requested in-service dates.[67] Based on my review of the record, those criteria are not satisfied for the full portfolio of seven CCCTs.

[62] Application at 23-24 and Prayer for Relief 5 at 28.

[63] See Beauchamp Direct at 77-80; see also May Direct at 29-30. The alternatives ELL describes having considered — an all-gas configuration with no renewable resources, a single 2x1 CCCT in lieu of two 1x1 CCCTs, and a transmission-only solution — were all internally developed, Company-owned supply-plan configurations.

[64] Application at 23-24 and Prayer for Relief 5 at 28; ELL response to data request NPO 3-16; *see* MBM Order, Attachment A, Rule 15 & n.5 (requiring an independent monitor where the utility proposes a self-build).

[65] 2024 MBM Order, Attachment A, Rule 11.

[66] Datta Direct, as corrected by ELL's June 10, 2026 Errata, at 32.

[67] *See* Lightning Initiative, Minutes of the LPSC Business & Executive Open Session, Dec. 17, 2025, at Ex. 22 (adopting the Commission's "Lightning Initiative"); *see also* Transcript of LPSC Business & Executive Open Session, Dec. 17, 2025, https://lpsc.louisiana.gov/docs/transcripts/December-17-2025-BE.pdf, at 59-60, 84.

Q. Did ELL perform any analysis regarding whether only some of the Proposed Generators could be pursued under the Lightning Initiative while allowing time for a competitive solicitation for the remaining need?

A. Not to my knowledge. When asked whether certification and construction could be phased or staged pending demonstrated load materialization, ELL responded that phasing or staging "would be inefficient and overburden the resources of the Commission, Commission Staff, the Company and intervenors and needlessly delay resolution of this matter."[68]

Q. Does ELL's response address your concerns?

A. No. For a proposed investment of this scale, regulatory oversight is not an inconvenience; it is a necessity. ELL's response addresses only administrative convenience and does not engage with the ratepayer protection rationale for phasing that as I explain in my testimony. Put differently, I do not think that it is an “inefficient” or burdensome use of Commission resources to fully evaluate a $16 billion capital investment that could have lasting impacts on customer energy bills for decades to come.

Q. What is your recommendation with respect to ELL’s request for the waiver of those ratepayer protections?

A. I recommend that, to the extent the Commission approves fewer than all seven proposed units, consistent with my *Recommendation 2*, the Commission require that any units not certified in this proceeding be subject to the full MBM process before future certification is sought, including a competitive solicitation, an all-source evaluation, and an independent monitor.

V. THE TERMS OF THE ESA DO NOT SUFFICIENTLY INSULATE CUSTOMERS FROM RISK EXPOSURE DUE TO SIGNIFICANT GAPS

[68] ELL response to data request NPO 5-23.

Q. Are there any provisions in the Energy Service Agreement between ELL and Evest that are intended to mitigate the risks you described earlier in your testimony?

A. Yes. As the Company describes, the ESA includes several important provisions that appear designed to provide protections to existing customers. Some of these include the following which are summarized in Table 4 of the Direct Testimony of Beauchamp:

- A 20-year initial term with 3-year non-renewal notice.
- A minimum monthly charge intended to cover the full incremental cost to serve during the contract.
- An early termination fee intended to pay all unrecovered costs
- Credit/collateral requirements for the customer[69]

All of these provisions are important contributions toward reducing the risk to existing customers. However, they do not sufficiently insulate ratepayers from many important risks.

Q. Are there any remaining gaps where such risks are not mitigated?

A. Yes. There are at least four significant gaps that I have identified in the ESA whereby existing customers are not sufficiently protected from the significant risk of the $16 billion proposed investment. These include the following:

- Gap No. 1 - The ability for ELL to request "Retained Generator" status for the new generation plants when a termination event is triggered.
- Gap No. 2 - The mismatch between the collateral and insurance requirements that ELL has requested and the underlying asset life and cost.
- [redacted].

[69] Beauchamp Direct at 18-19, HSPM/AEO Table 4.

- Gap No. 4 – The risk that the Customer will not seek renewal of the ESA term after 20 years

A. Gap No. 1 – Retained Generator Status

Q. Can you please elaborate on each of these starting with Gap No. 1?

A. Yes. Gap No. 1 arises due to the fact that upon early termination of the ESA by the Customer, ELL will have the opportunity to designate the new generators as "Retained Generators."[70] In this case, there is a significant risk that the remaining incremental costs of these facilities will be borne by existing customers as ELL seeks to recover remaining costs through retail rates.

Q. If the new generators are designated as Retained Generators, will the Company be able to protect other customers by recovering the net book value of those generators from the Customer?

A. No. As Ms. Beauchamp explained, the early termination provisions of the ESA only apply to generators that are "not retained by the Company for general supply purposes."[71] As such, the ESA is not designed to protect existing customers in the event that the new generators are designated as Retained Generators during the termination process.

Q. Does ELL have a natural incentive to seek Retained Generator status in the event of an early termination?

A. Yes. Under the standard cost-of-service regulation framework that exists in Louisiana, ELL will have a natural incentive to pursue this option since it will keep the assets within the Company's rate base upon which it earns a shareholder return. In this respect, the Retained Generator option stands in contrast to the other termination options such as dismantling the generators or selling them, which would not provide the same benefit to ELL shareholders.

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[70] May Direct at 44:15-45:9.

[71] Beauchamp Direct at 33:8.

Q. Has ELL proposed any specific criteria for determining when and how it would elect Retained Generator status upon early termination?

A. No. The Company has provided vague statements about the termination process explaining that "ELL will identify which Proposed Generators … ELL believes it should retain to benefit other customers (the 'Retained Generators')."[72] However, the Company has provided insufficient explanation of how it defines "benefit to other customers" or how that benefit will be quantified. In response to a discovery question, ELL stated that "potential surplus capacity relative to the ELL retail load represents a benefit to ELL retail customers because surplus capacity could either be sold or used to displace resource additions that would otherwise be needed."[73] However, this explanation is insufficient as it suggests that any surplus capacity – no matter what amount or what cost – constitutes a benefit to retail customers. By this definition, ELL should always be adding as much surplus capacity as it can *ad infinitum* while ratcheting up customer bills accordingly.

Q. Has ELL's proposal explained how much of a Retained Generator's costs it might seek to recover from retail customers?

A. No. More specifically, the Company's proposal does not explain what portion of the remaining net book value of the Retained Generators it would seek to recover through retail rate recovery and what portion would be at risk to its shareholders. Since the Company has not articulated any risk sharing arrangements for Retained Generator costs, the Commission should presume that the Company intends for 100% of the risk to be borne by existing customers and 0% of the risk to be borne by its shareholders.

Q. Do you think ELL's proposal represents a fair or appropriate risk sharing arrangement?

A. No. The Company's shareholders should be responsible for bearing at least some amount of the cost risk in the event of an early termination. That does not appear to be the case

[72] May Direct at 44:18-20.

[73] ELL response to data request NPO 3-18.

under the Company's proposal, since 100% of the cost risk can be shifted to existing retail customers. In this circumstance, some form of risk sharing would be appropriate in exchange for the benefit that ELL receives in the form of the opportunity to earn a regulated rate of return on over $16 billion in invested capital. Importantly, existing ratepayers are not the cost causers of this investment and do not deserve to absorb all of the associated cost risk.

Q. Are you concerned that ELL would seek to elect Retained Generator status (and subsequently seek cost recovery from existing customers) even if the Customer seeks early termination and the Proposed Generators are no longer needed?

A. Yes. As explained earlier, the Company has not set forth any robust criteria for determining what constitutes sufficient customer benefit to designate Retained Generator status. In fact, the Company may simply assert that having a surplus capacity constitutes sufficient benefit, regardless of the costs to existing customers. As noted above, the Company stated that "potential surplus capacity relative to the ELL retail load represents a benefit to ELL retail customers…" Thus, ELL could simply claim that having surplus capacity constitutes a sufficient benefit to existing customers. It is not clear that ELL will seek to provide any further cost-benefit evaluation to support a Retained Generator designation or subsequent cost recovery.

Q. Does ESA Rider 1, Section 8 address this concern?

A. Partially, but further Commission action is necessary for this provision to be effective. Under ESA Rider 1, Section 8, it appears that the following may be true:

[redacted]

[redacted]

Thus the ESA explains tha[redacted]. Given the significant risk this would potentially pose to existing customers, it is important that the Commission take action to ensure that any such future proposal adheres to a set of clear and rigorous evaluation criteria that the Commission establishes. Such criteria, which are not prescribed in any way in the Electric Service Agreement, should be established well in advance of any such proposal that comes before the Commission.

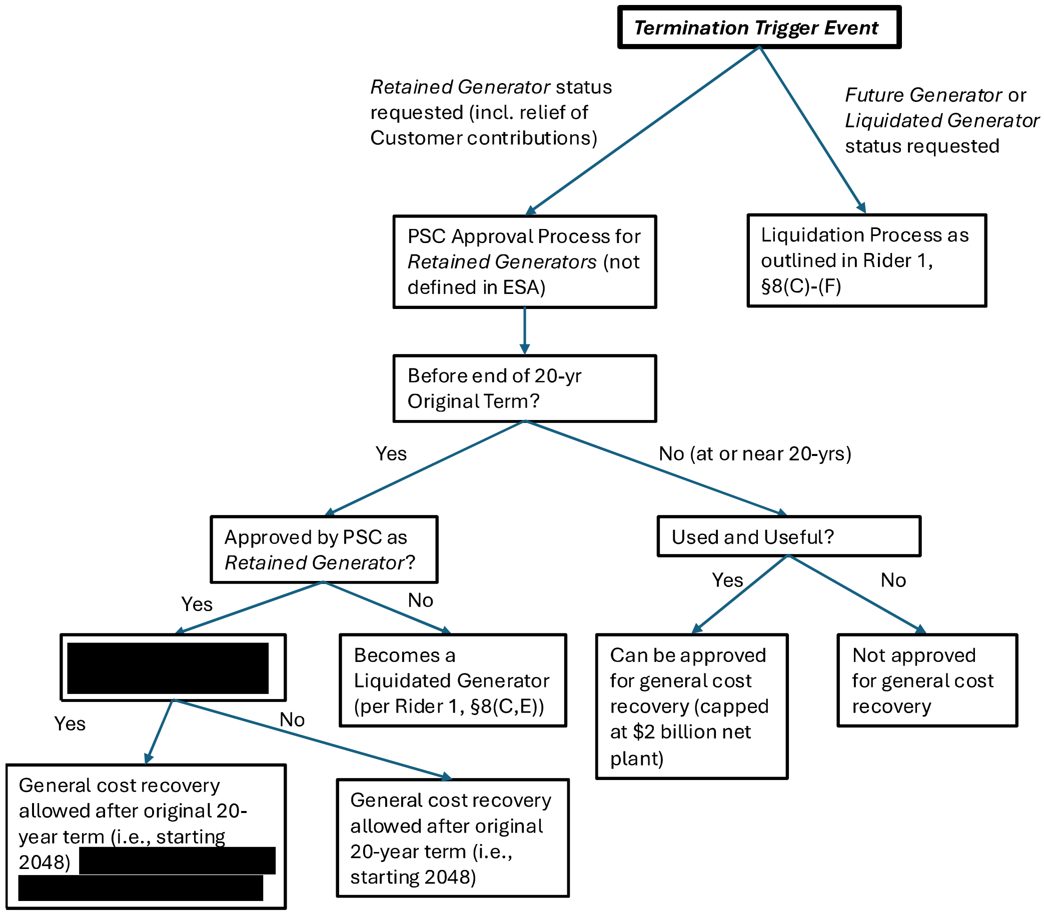
Q. Does the Company provide any recommendations for how the Commission should evaluate future requests for Retained Generator status and associated cost recovery?

A. No.

Q. Do you have any recommendations for how the Commission should evaluate such future requests?

A. Yes. If the Commission approves the Company's primary request in this proceeding, it should simultaneously establish a standard process for reviewing and approving Retained Generator status well in advance. I recommend that this process follow the left path of the decision tree illustrated below following a Termination Trigger Event:

[74] Beauchamp Direct, Ex. LKB-2 (HSPM / AEO) at 48-51.



Q. Can you describe the steps in this Retained Generator evaluation process in more detail?

A. Yes. Under this evaluation process, the first question for the Commission to consider will be whether the Retained Generator request comes at the conclusion of the 20-year ESA term. If the request comes well before the end of the original 20-year term, it suggests that the contract was terminated early by the Customer. In such a case, the Commission should only consider approving the Retained Generator status if its costs are not passed on to existing customers because these costs were incurred to serve the Customer's contracted load which was expected for the full 20-year term. To that end, an approved Retained Generator (left-most path) should only be allowed general cost recovery beginning at the end of the original 20-year contract term (*i.e.*, 2048).

The Commission could also apply other criteria (*e.g.*, cost-effectiveness evaluation) that could lead to a rejected request, [redacted]. The ESA terms also specify that if an approval is made [redacted] my recommendation to only allow general cost recovery beginning at the end of the original 20-year contract term.

Q. If general cost recovery is not allowable, will this preclude the Company from seeking any form of cost recovery for a Retained Generator before the end of the 20-year term?

A. Not necessarily. To the extent that ELL is able to identify a large "replacement load" to utilize the proposed Retained Generators, it may be able to make a similar request to the Commission. However, this "replacement load" should be in the form of another durable ESA (or ESAs) for a large customer rather than the general customer base. In setting these criteria, the Commission would ensure that the Company appropriately shares in some of this risk of an early termination. Specifically, if the Company is unable to identify a replacement load, it bears the risk that some of the remaining plant costs will go unrecovered. I believe this is an appropriate step to mitigate the risk under the Company's proposal that existing customers will bear the costs of the Proposed Generators in the event of an early termination.

Returning now to the earlier part of the decision tree, if the request comes at the conclusion of the original 20-year term, this indicates that the contract was not renewed. I discuss this "non-renewal risk" more fully in Section V-D of my testimony below and

[75] *Id.* at 50.

provide corresponding recommendations. Briefly, in this case the plant would be evaluated to determine if it were still "used and useful" in which case it could be treated similarly to a Retained Generator with cost recovery capped based on net plant value of [redacted] as described in Section V-D.

Q. Doesn't the ESA specify that the expiration of the agreement [redacted] and therefore the Retained Generator status [redacted]?

A. Yes. However, I recommend that the Commission apply this "end of term" consideration to any Termination Event that occurs very close to the end date of the contract term (*e.g.*, within 18 months of expiration). Additionally, the cost recovery cap should remain even after the expiration of the agreement.

Q. What is the Commissioning Period?

A. The Commissioning Period extends from the Service Commencement date through the in-service date of the last-constructed Proposed Generator. Based on the information in Exhibit LKB-9, ELL expects this to extend from approximately [redacted] through the end of [redacted].

Q. Could new resources that are still under construction during the Commissioning Period be designated as Retained Generators after a Termination Trigger Event occurs?

A. Yes. ELL confirms this in the Direct Testimony.[76]

Q. Would existing customers be protected from paying the costs of these resources?

A. No. ELL explained that the customer protections in the ESA should "generally ensure" that ELL recovers costs to construct assets that are not yet in service.[77] However, ELL also specifically identified several resources for which this is not true, including Retained

[76] Beauchamp Direct at 35:4-11 (HSPM).

[77] *Id.* at 35:5 (HSPM).

Generators. ELL asserts that this is appropriate because these resources "have independent value (and would have been pursued in the absence of the Customer)."[78] As explained above, the ESA anticipates that the LPSC may also have some discretion in this matter, however the Commission has not established clear and rigorous criteria for determining the "independent value" that witness Beauchamp describes.

Q. How do you interpret these statements?

A. There are several points worth noting here: First, ELL appears poised to designate the new generators as Retained Generators, even if termination occurs early on during the Commissioning period and before construction is completed.

Second, ELL also appears to believe that any resource requested for Retained Generator status should automatically be presumed as beneficial even in the Customer's absence.

Meanwhile, Retained Generators are excluded from the general provisions that would otherwise protect existing customers from paying unrecouped costs after a termination trigger.

Importantly, under ELL's proposal, a termination trigger event could include [redacted]

Q. What do these facts suggest to you?

A. When taken together, these facts suggest that there are little to no guardrails at present to protect existing customers from absorbing unrecouped costs of the Proposed Generators after a termination event occurs. This lack of guardrails applies to cost overruns for

[78] *Id*.

[79] Beauchamp Direct, Exhibit LKB-2 at 54 (ESA, Rider 1, Section 9(C)).

generators still under construction, and revenue shortfalls due to [redacted]. This lack of protection is primarily due to the option for ELL to designate Retained Generator status for the proposed plants and will persist unless the Commission takes concerted action in advance to establish clear evaluation criteria.

Q. Do you have any recommendations to the Commission for how to address Gap No. 1?

A. Yes. The PSC should ensure ELL does not unfairly seek to shift the risk of early ESA termination from shareholders to existing customers. Accordingly, if ELL elects Retained Generator status upon termination and obtains Commission approval, the remaining net plant of any such generators should be ineligible for general cost recovery until the end of the original term. This is necessary to ensure that ELL shareholders, not just existing ELL customers, assume some risk in the execution of the ESA with Meta. Furthermore, exposing shareholders to some of this risk should appropriately motivate ELL to hold Meta accountable for maintaining sufficient collateral and insurance coverage throughout the contract term.

B. Gap No. 2 – Collateral and Insurance Requirements

Q. Beyond the normal minimum monthly payments over the term of the ESA, what other steps has ELL sought to mitigate potential cost risk to existing customers?

A. In addition to the contract payment terms, ELL has required the Customer to guarantee financial security in the form of both [redacted] and insurance coverage. The schedule for these securities is provided in Appendix E of the ESA copied below:

Table 5: Security Schedule (HSPM / AEO)

[redacted]

Q. What is the purpose of these instruments?

A. As discussed in the testimony of Thomas Kidd, there is a risk that the Customer might not pay its obligations on time in accordance with the Customer Agreements. As a means to ensure that ELL receives payment under these agreements, "the Company required the Meta Guaranty, [redacted], and Credit Default Security."[80] According to ELL witness Hinkson, the Company's approach of requiring these financial securities will "reasonably mitigate risks to other customers, as well as ELL, from a Customer default of non-payment."[81]

Q. Do these three instruments provide equivalent protection (commensurate with their values) against risks to existing customers?

[80] Kidd Direct at 26:7-8.

[81] Direct Testimony of Kenroy Hinkson at 3:13-14 ("Hinkson Direct ").

A. No. In particular, I'm concerned that ELL and existing customers would have little recourse to recoup the value of the parent guaranty in the event of non-payment. The parent guaranty is not tied to a specific letter of credit, cash deposit, or insurance policy. As such, I do not believe the parent guaranty provides the same level of risk mitigation in the event of non-payment. Therefore, it should not be considered in the same category as the other forms of security such as the [redacted] and credit default security (*i.e.*, insurance), both of which provide a greater level of certainty.

Additionally, it appears that the Company has received no additional information from Meta on how to collect these funds beyond public filings describing Meta's location, the guaranty amount, and the nature of their assets.[82] Although I'm not a lawyer, I believe that collecting on a parent guaranty would also require that a lawsuit be filed in a particular jurisdiction. Furthermore, while Meta is a large company with annual revenues of $215 billion, its underlying assets are far from certain. For example, on July 7th, it was disclosed that states are seeking $1.2 trillion in damages from Meta in a federal court lawsuit.[83]

Q. Do you think ELL's approach of requiring [redacted] based on credit rating is sufficient to overcome these concerns?

A. No. Notably, ELL would not require this [redacted] until the parent company [redacted],[84] at which point it may be much more difficult or costly for the parent company to obtain the necessary cash or letter of credit. Additionally, this additional protection would be of no benefit to existing customers if ELL elected Retained Generator status, thereby sidestepping the liquidation process.

Q. Beyond the parent guaranty, do you believe the Company's required securities are sufficient enough to protect existing customers from the risk of higher costs?

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[82] ELL response to data request AAE 1-3.

[83] Diana Novak Jones, *Meta says US states are seeking $1.4 trillion in penalties in August youth safety trial*, Reuters (July 6, 2026). https://www.reuters.com/business/meta-says-us-states-are-seeking-14-trillion-penalties-august-youth-safety-trial-2026-07-07/.

[84] Hinkson Direct at 9:13-10:1, Table 1 (HSPM / AEO).

A. No. While the financial securities being requested of the Customer are significant, they are still insufficient relative to the large scale of the investment ELL is undertaking. I am concerned existing customers would still be significantly impacted in the event of Customer non-payment. This risk arises due to a mismatch between the overall security levels and the overall cost exposure at various points throughout the life of the contract.

Q. Have you performed any analysis to quantify or illustrate this mismatch between the financial securities and the cost exposure?

A. Yes. The table below summarizes this mismatch.

Table 6: Summary of Net Plant and Coverages (HSPM / AEO)

	Total Net Plant	Sum of Coverages (excl. Parent Guaranty)	Net Plant in Excess of Coverages
2028	[redacted]	[redacted]	[redacted]
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
2038			
2039			
2040			
2041			
2042			
2043			
2044			
2045			
2046			
2047			
2048			

The first column shows the Total Net Plant, based on the information provided in Exhibit RDJ-2 (HSPM/AEO). This represents the remaining fixed cost that existing customers may be required to cover in the event of the Customer's non-payment. As shown, this value peaks around [redacted] in 2032 and eventually declines to [redacted] at the end of the ESA term in 2048. Notably, the net plant value does not reach zero at the end of the ESA term, meaning that the incremental cost is not fully recovered by ELL from the Customer during the life of the contract and [redacted] in remaining costs may still fall to other customers at the end of the 20-year term. The second column shows the sum of [redacted] and credit default insurance coverage values. Notably, this amount peaks at about [redacted] in 2031 and declines to [redacted] by 2048. The third column calculates the difference between these values and indicates the potential risk exposure that could impact existing customers. The same amounts are shown in the figure below. The gap between the dashed line and the blue areas represents the Net Plant in excess of coverages that presents a risk to existing customers.

Figure 2: Coverages and Net Plant (HSPM / AEO)

[redacted]

Q. Has ELL acknowledged that its insurance coverage does not equal the total exposure?

A. Yes. As shown in Exhibit RDJ-2, the amount of insurance coverage is estimated by the Company to be approximately [redacted] of the Total Exposure throughout the life of the contract.[85]

Q. Did ELL size the Credit Default Security (insurance) coverage based on what is necessary to fully protect existing customers?

A. No. As Mr. Kidd explained, the amount of coverage available from the market was limited. Specifically, he stated "the size of the market capacity for instruments of this type currently provides coverage at a maximum of approximately [redacted]."[86]

Thus, the gap in coverage appears to be partly due to limitations in the insurance coverage the market is willing to offer, rather than what is best for ELL's customers.

Q. Is the initial term of this insurance coverage expected to equal the life of the contract?

A. No. As the Company confirmed in response to discovery, the initial term of the Credit Default Security would likely be 3-5 years,[87] in contrast to the ESA term of 20 years. Thus, there is an additional risk to existing customers if this insurance coverage is not maintained beyond an initial 3-year term. Furthermore, ELL also stated that these insurance premiums will be paid annually.[88] Meanwhile, the projected cost of the premium is collected through the MMC based on a 20 year levelized value with no true-up for the actual cost of the premium that is actually paid.[89] Therefore, it follows that the portion of premiums that ELL is responsible for could substantially increase year-over-

[85] According to the Company's workpaper "Guaranty Support" in Ex. RDJ-2 (HSPM / AEO), Total Exposure is calculated as the sum of the following: [redacted].

[86] Kidd Direct at 29:11-13.

[87] ELL response to data request Staff 1-92.

[88] ELL response to data request NPO 7-1.

[89] *See* ELL responses to data requests Staff 1-30 and 1-45.

year; or the Credit Default Security insurance coverage (and associated premiums) could simply go away in the event of non-payment.

Q. What would the increased risk exposure to existing customers be if the insurance coverage is not renewed?

A. If the insurance coverage were not renewed after 3 years, the potential risk exposure to ELL's existing customers would be approximately [redacted] and remain at that level for several years before gradually declining. The table below illustrates this by comparing the Total Net Plant (in excess of coverages) from the table above to the same value with the insurance contribution removed after 3 years:

Table 7:Net Plant in Excess of Coverages by Year (HSPM / AEO)

Year	Net Plant in Excess of Coverages	Net Plant (insurance non-renewal after 3 yrs)
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]
2041	[redacted]	[redacted]
2042	[redacted]	[redacted]
2043	[redacted]	[redacted]
2044	[redacted]	[redacted]
2045	[redacted]	[redacted]
2046	[redacted]	[redacted]
2047	[redacted]	[redacted]
2048	[redacted]	[redacted]

Q. Based on these risk factors, do you think that the required collateral presented in ELL's application is sufficient to protect existing customers in the event of a termination?

A. No. Even with the [redacted] requirements, existing customers may be exposed to over $[redacted] in increased net plant costs in the event of an early termination.

Q. What changes do you recommend to ensure that existing customers are sufficiently protected from these risks?

A. There are two specific changes that I would recommend. First, I would recommend that the requirements for [redacted] be increased from the currently proposed levels to at least 50% of the value of the Total Net Plant, as updated on an annual basis. This will ensure that Meta has sufficient "skin in the game" to cover at least half the costs that might otherwise fall to existing customers. This change is also necessary since larger insurance products appear to be unavailable in the market at present.

Second, consistent with my testimony on Gap No. 1, I would recommend a Commission ruling in this proceeding such that upon designating any plant as a Retained Generator in the future, the remaining Net Plant be ineligible for general cost recovery until the end of the 20-year contract period. This will ensure that existing ratepayers are fully protected in the event of non-payment and that ELL is not simply able to shift all risk to captive ratepayers by electing Retained Generator status. This should also motivate ELL to ensure that Meta's collateral obligations remain sufficient, since ELL's shareholders would bear the consequences of any non-payment.

C. Gap No. 3 – Load Ramp Uncertainty

Q. Is there any single assumption about future conditions that is most central to ELL's proposal?

A. There are many key assumptions; however, the most important assumption underpinning the entire proposal is the likelihood of the load ramp forecast provided by Meta. This key assumption dictates the overall magnitude and timing of the resource need that underpins ELL's proposal.

Q. What data did ELL rely upon in conducting its forecast of Meta's load?

A. ELL relied on a single load ramp projection provided by Meta in [redacted]. This was not updated prior to ELL's application or during the pendency of this case.[90]

Q. Have there been new developments since [redacted] that might cause Meta's load ramp to be different if it were provided today?

A. Yes. The data center industry is incredibly dynamic and many factors could change over the course of 1-2 years that would impact the load forecast at a particular location. As one example of some relevant recent news, Meta announced that it would be launching a new business venture to sell "excess computing power" to outside customers.[91] This development is noteworthy in several respects – first it is an acknowledgement that Meta's internal demand for computing power may be lower than previously expected. Second, it suggests that the specific load ramp at the Evest site may be partially dependent on an emerging business plan within Meta Platforms which may or may not be successful.

Q. Does Meta have the ability to change its load ramp over the course of the 20-year ESA?

A. [redacted]. As explained by ELL witness Beauchamp, "[redacted][92]

[90] Beauchamp Direct, Exhibit LKB-9 at 1, n.1 (HSPM).

[91] Riley Griffin & Kurt Wagner, *Meta is Planning a Cloud Business to Sell AI Computing Power,* Bloomberg (July 1, 2026), https://www.bloomberg.com/news/articles/2026-07-01/meta-is-building-a-cloud-business-to-sell-excess-ai-compute.

[92] Beauchamp Direct at 35:15-16 (HSPM).

Q. Does the ESA include any limitations on how much the Customer can [redacted]?

A. [redacted]

Q. Does the proposed ESA explain what will occur to any excess generators that are in service but [redacted]?

A. According to Section 9(C) of Rider 1, any "[redacted].[93] I am concerned this could mean that a generator no longer needed [redacted] could still be designated by ELL as a Retained Generator just as described earlier in my testimony. While Section 9(A) suggests that [redacted]

Q. Did ELL conduct any sensitivity analyses to reflect the range of potential [redacted] that are permitted under the ESA?

A. No. Given the criticality of the [redacted], this appears to be a significant oversight in ELL's application.

D. Gap No. 4 – Non-Renewal Risk

Q. Are the proposed terms of the ESA intended to cover all of the incremental costs of the Proposed Generation?

A. No. As explained above, at the conclusion of the 20-year term, there will still be approximately [redacted] in undepreciated Net Plant that has not been recouped through

[93] Beauchamp Direct, Exhibit LKB-2 at 54 (HSPM).

the MMC payments. This represents an additional cost that could be borne by existing customers if ELL requests general cost recovery for those assets.

Q. What does ELL's analysis assume regarding those remaining fixed costs?

A. ELL assumes that these remaining fixed costs will be covered through a potential contract extension or renewal, even though such a renewal has not yet been executed.

Q. Do you think this is an appropriate assumption?

A. No. The cost benefit analysis should be based on the terms of the ESA under consideration today, not some future ESA that has yet to be considered by the parties involved.

Q. Does this remaining end-of-term cost reflect a risk to existing customers?

A. Yes. It is important to note that ELL assumes future contract renewal, but this is far from certain. Thus, even if the Customer completes the full 20-year term of its agreement and provides all associated payments on time, there is still a risk that existing customers will bear an incremental cost for unneeded assets at the conclusion of that agreement. This constitutes a "non-renewal" risk that is distinct from the risks from termination [redacted] that I described earlier.

Q. What do you recommend to mitigate this risk?

A. There are two potential steps that could mitigate this risk. First, ELL's cost benefit analysis should not automatically presume that any extension will occur. Second, if ELL is inclined to make this assumption, it should also require the ESA to include a corresponding end-of-term protection, for example, an end-of-term payment obligation covering the remaining net plant. This way, the risk of non-renewal is borne by the Customer rather than by existing ratepayers. Finally, in the case of non-renewal, retail rate recovery of any remaining costs should be capped at an appropriate level to ensure that ELL does not pass 100% of the risk of non-renewal on to its captive customers. Such a cap will also properly motivate ELL to seek a contract extension on behalf of its existing customers. I recommend that this cap be set based on $[redacted] of Net Plant value, [redacted] Net Plant remaining in 2048 estimated by the Company. Thus, this reflects an equal sharing of risk between the Company and customers. The Commission should also evaluate a generating plant's used and useful status at the time as a threshold for approving any cost recovery.

VI. THE PROPOSED DEVELOPMENT TIMELINE POSES SIGNIFICANT EXECUTION RISK

Q. What is ELL's proposed timeline for placing each of the Proposed Generation units in service?

A. ELL proposes the following schedule for placing the proposed seven new CCCTs in service:

- April 2030: Richland 1 & 2
- Nov 2030: Richland 3 & 4
- Jan 2031: Pointe Coupee 1 & 2
- July 2031: Pointe Coupee 3[94]

Q. Does this development timeline seem problematic to you?

A. Yes. When considering major generation buildouts, they must be evaluated from both a planning risk and execution risk standpoint. So far, my testimony has focused on planning risk. Setting aside any consideration of what the ideal schedule and timeline might look like from a planning perspective, this proposed timeline also appears to pose significant execution risk due to the overlap and coincidence of several major construction projects.

[94] Grunden Direct at 30:12. Commercial operation date goals stated here and throughout this testimony refer to the first of the month.

Q. Is ELL's proposal unusual in terms of its execution timeline?

A. Yes. In over a decade of my experience analyzing utility resource plans, I cannot recall ever seeing such a significant buildout of new large-scale baseload generation projects by one utility within such a short and concentrated period of time. More typically, large generation projects such as combined-cycle unit additions occur on a staggered timeline with each unit being added a year or two apart. This allows adequate time for construction crews to be mobilized while adhering to appropriate labor and safety protocols. In contrast, ELL is seeking to complete six major new baseload generation projects within the span of 10 months, and a seventh following soon after. This does not even account for three additional combined cycle units that were approved last year in Docket No. U-37425, and the two additional ones that ELL is concurrently seeking approval for this year in Docket No. U-37853.

Q. What are the potential risks of pursuing such a concentrated timeline?

A. By concentrating the development in this manner, rather than using a more staggered approach, ELL could be exacerbating the risk of cost overruns if contractors encounter difficulty sourcing parts and labor on an expedited timeline. Additionally, this risks potential substandard safety and labor protocols.

Q. Has ELL taken steps that may reduce some of the potential cost overrun concerns?

A. Yes. According to the Company's testimony, they appear to have secured a turbine order from Mitsubishi,[95] and ELL has subsequently stated that turbine pricing is established through their EPC contract.[96] However it is unclear to me that this will eliminate all potential cost increases. Additionally, it is still unclear how this price certainty will resolve the execution challenges associated with mobilizing adequate construction labor within the proposed time window.

[95] Grunden Direct at 27:3-4.

[96] ELL responses to data requests Staff 1-146 and Staff 1-151.

Q. What do you recommend to address this execution risk?

A. I recommend that the Proposed Generators be constructed on a more staggered timeline that spaces their in-service dates 6-12 months apart, as is more typical. Furthermore, I recommend that the Commission consider its approval of each unit on a more staggered timeline within this docket and allow the decision to be informed by the most up-to-date information about Meta's load forecast. It would also allow for a more thorough cost-benefit analysis to be conducted (including sensitivity analyses) on what potentially constitutes a "once in a generation" investment in ELL's resource portfolio. For example, the initial approval decision could be limited to just Richland Units 1 & 2 (Group A), with a subsequent approval decision for Units 3 and 4 after six months (Group B), with a decision later on the Pointe Coupee units (Group C) as follows:

Table 8: Gas Unit Timeline, ELL and NPO Proposed

Group	Units	ELL Proposed Decision Date	ELL Proposed COD	Timeline (months)	NPO Proposed Decision Date	NPO Proposed COD	Timeline (months)	Add'l Decision Time (months)
Group A	Richland Unit 1	Nov 2026	Apr 2030	42	Jan 2027	July 2030	42	2
	Richland Unit 2	Nov 2026	Apr 2030	42	Jan 2027	Jan 2031	48	2
Group B	Richland Unit 3	Nov 2026	Nov 2030	48	July 2027	May 2031	47	8
	Richland Unit 4	Nov 2026	Nov 2030	48	July 2027	May 2031	47	8
Group C	Pointe Coupee Unit 1	Nov 2026	Jan 2031	50	Jan 2029	After Jan 2033	48	26
	Pointe Coupee Unit 2	Nov 2026	Jan 2031	50	Jan 2029	After Jan 2033	48	26
	Pointe Coupee Unit 3	Nov 2026	July 2031	57	Jan 2029	After Jan 2033	48	26

Q. Why did you select these dates for NPOs' proposed Commission review events?

A. I selected these dates to increase the amount of time the Commission has to deliberate on each unit, while also maintaining approximately the same timeline for each unit's construction as what is in the Company's proposal. Under this proposed approach, only

Richland Units 1 and 2 (*i.e.*, Group A) would conceivably need to be considered for expedited treatment under the Commission's Lightning Initiative. The other units could be considered through the more typical deliberation schedule that would be appropriate for a $16 billion investment backstopped by existing ratepayers.

Q. Are there other advantages to a staggered approval process?

Yes. This staggered approach would ensure that less overall cost and risk was at stake in any one individual decision that the Commission must make in the near term. It would also have the advantage of giving ELL and the Commission additional flexibility to modify its approach if it turns out that the load forecast was less robust (or more robust) than initially anticipated [redacted]. It would also enable the Company to conduct competitive solicitations in accordance with the MBM. Finally, it would more appropriately balance the needs of the Customer with both risks to existing customers and execution risks.

Q. Are you concerned at all about the additional Commission resources this staggered approach will require and the administrative burden that could cause?

A. I am cognizant that this approach may require additional resources and administrative steps. However, given the sheer magnitude of cost and risk from the Company's request, I think this represents a unique case where additional review is wholly appropriate. According to ELL's workpapers, the proposal before the Commission will increase the Company's annual revenue requirement by more than $[redacted] by 2031.[97] That is the equivalent of [redacted] the Company's entire residential customer class. Any unintended consequences generated by the Commission's lack of oversight could be catastrophic in terms of the impact to existing customer bills. Of all the requests that have come before the Commission for approval within the last decade, this one probably ranks among the highest for warranting more deliberation rather than less.

[97] Jones Direct, Exhibit RDJ-2 at 5 (HSPM / AEO).

VII. ALTERNATIVE NEAR-TERM RESOURCE PLAN (2027-2033)

A. ELL's analysis does not establish that the proposed portfolio is the lowest cost or lowest risk option.

Q. What is the incremental load on ELL's system driven by the Customer?

A. The Customer's load ramps up to a maximum of [redacted]

Q. Did ELL conduct an adequate analysis to evaluate the range of resource options that could serve that load?

A. Not an adequate one. Within a very narrow sense ELL did perform an "alternatives analysis." However, ELL's narrow analysis did not meaningfully explore a full range of possible options or whether a lower-cost or lower-risk portfolio could serve this load. First, taking the Customer's projected load as given, ELL's analysis does not establish that the proposed portfolio is the lowest reasonable cost means of serving it. Second, despite the uncertainty around load materialization and the consequential nature of any shortfall, ELL did not explore options that could serve the projected load but do so at lower risk to existing ratepayers.

Q. Why do ELL's economic analysis, presented by ELL witness Datta, and the alternatives analysis, presented by ELL witness Beauchamp, not establish that the proposed portfolio is the lowest cost?

A. ELL's analyses were limited in scope and not oriented toward determining whether the proposed portfolio and timeline are economically optimal.

Specifically, ELL's economic analysis, presented by ELL witness Datta, consists of two AURORA production cost model runs: a Base Case with no Project Evest and a Change Case with the full proposed portfolio as filed. Both runs had pre-determined portfolios and were conducted under a single gas price scenario and a single carbon policy assumption. No alternative resource portfolio was modeled in AURORA. The Change Case includes all proposed resources as a single package: seven CCCTs, three BESS facilities, and the transmission facilities. That structure does not allow the Commission to evaluate the relative cost and value of individual components. For instance, some subset of the proposed resources may generate net benefits for existing customers while others do not. For example, the transmission facilities and early BESS additions may be beneficial on their own terms, while the later Pointe Coupee CCCTs, which enter service last, carry the highest per-unit cost, and face the most significant gas supply constraints, may not clear the same threshold. A phased analysis evaluating each resource tranche independently would provide the Commission with more information for the evaluation of this Application.

ELL's alternatives analysis, mainly presented by ELL witness Beauchamp, considered three alternatives: an all-gas portfolio with no renewables, a 2x1 CCCT configuration in lieu of two 1x1 units, and a transmission-only solution.[98] ELL witness Owens also briefly considered nuclear and wind or solar combined with storage, but concluded that the intermittent nature of renewables and the storage required to firm them for around-the-clock service would be infeasible.[99] However, those alternatives do not constitute a meaningful alternatives analysis. None of them tests whether a combination of a smaller CCCT buildout together with additional storage, higher levels of demand response ("DR") and energy efficiency ("EE"), or a firmer renewable commitment could serve the Customer's load at comparable reliability, lower cost, and/or lower risk for existing ratepayers.

Q. What would a more appropriate analytical approach look like?

A. ELL's modeling was not oriented towards determining whether the proposed resource portfolio and timeline are economically optimal and deviates from planning best practices. A better planning approach, and one that is frequently used by utilities like

[98] Beauchamp Direct at 77:9-78:2.

[99] Owens Direct at 6:6-17.

ELL, would be to conduct capacity expansion modeling to identify the optimal type and timing of resource additions. ELL did not conduct any capacity expansion modeling and only assessed a single set of resource options along a single timeline. Furthermore, ELL did not conduct any sensitivity analyses to understand how that portfolio would perform under different assumptions, including a slower load materialization, different fuel prices, or other changes.

Q. Beyond the question of whether the proposed portfolio is the lowest cost way to serve the projected load, do you have other concerns about ELL's resource plan?

A. Yes. Setting aside the expected cost of ELL's plan, my larger concern is its risk profile. I am not persuaded that ELL's analysis was adequate enough to rule out the existence of a resource plan that could serve the same projected load but with a lower risk profile for existing ratepayers.

There is a key distinction between the short-term needs where the initial focus should be on [redacted], and the long-term needs to sustain the customer's maximum over the 20-year contract term. Thus, to the extent possible, it may be fruitful to consider certain "short-term" resource options that are timely and temporary in nature but can support the initial load ramp, while allowing time for more robust consideration of the long-term resource options.

There is a significant risk of over-investing in long-term resources on an expedited basis. CCCTs built today will have cost implications for all customers lasting decades. Expediting their construction without any chance for competitive solicitation is a risky strategy that could lead to cost overruns, stranded costs, and a sub-optimal portfolio that ratepayers will carry long after the ESA term ends. Thus, some amount of delayed procurement, even if just for a portion of the Customer's load ramp, would be beneficial in terms of ensuring costs are kept to a minimum and competition is robust.

Q. Does ELL's plan exactly meet the capacity needs of the Customer's projected load ramp?

A. No. ELL's plan actually [redacted] the projected load ramp. More specifically, ELL's own analysis shows a [redacted] growing from approximately [redacted], as the planned result of the proposed portfolio.[100] Thus, there is a significant risk that ELL's plan will [redacted].

Q. Is the risk [redacted] contingent on the Customer's load not materializing as projected?

A. No. In this case, [redacted] is not just a risk that is contingent on load falling short; [redacted]. The risk of load not materializing would only exacerbate [redacted]. Notably, the surplus amounts I mentioned above [redacted] do not account for the [redacted] for all those years, which, if included among the other Load Modifying Resources, would result in an even higher planned surplus.[101]

What is uncertain, and therefore genuinely a risk, is whether the planned surplus will have any market value. ELL credits surplus capacity as a benefit to existing customers at the avoided cost of a combustion turbine, but that credit depends on the surplus clearing at an equivalent value in the MISO capacity market, which is far from certain. The cost of over-building, by contrast, is much more certain.

[100] Datta Direct, Exhibit SD-2 (HSPM / AEO), as revised by ELL's June 10, 2026 Errata, "Analysis" tab, row 48 (Surplus/(Deficit), MW).

[101] Datta Direct at 22:18-22 [redacted] (HSPM); ELL response to data request Staff 1-56(a) [redacted] However, spreadsheet "Staff 1-1 BP26 and Evest L&Cs_HSPM," which informs the capacity surplus/shortage values in Exhibit SD-2, shows that the Load Modifying Resource is [redacted].

In short, in an effort to avoid a near-term transitionary capacity shortage driven by the Customer's load ramp and the coincident retirement of existing resources and expiration of PPAs (prior to their replacement resources or other planned resources coming online), ELL is proposing to overbuild large-scale, capital-intensive, long-lived gas resources that carry ongoing operating risks including fuel price volatility and carbon policy exposure, with the assumption that surplus capacity can then be sold into the market at a high enough price to benefit customers. By contrast, there are other near-term solutions that can meet the load ramp, while they can also mitigate costs and risks not only in the scenario where load does not materialize as projected, but also in the scenario where it does. If the load materializes as expected, those alternative solutions reduce the degree of overbuilding and preserve competitive options for the long-term resource need. If the load does not materialize, the value of having avoided the full capital commitment is simply higher.

Q. If the Customer is willing to pay a higher cost than necessary, should the Commission still be concerned about the resources being pursued?

A. Yes. Existing customers are not fully protected from the cost risks of the resources being pursued, as discussed throughout my testimony. Given that exposure, the Commission should ensure that ELL's resource decisions are as aligned as possible with planning best practices to minimize cost, and risk, regardless of what the Customer is willing to pay.

B. An alternative near-term resource plan can meet the Customer's load ramp at lower risk to existing ratepayers.

Q. Are there alternative resource portfolios beyond what ELL proposed that could also meet the Customer's needs?

A. Yes. ELL has focused almost entirely on rapid construction of seven new combined cycle generation to provide incremental energy and capacity to meet the Customer's needs. However, there are many other resource portfolio options and timelines that could cost-effectively contribute towards meeting these needs – even if only partially – and could assist in delaying or avoiding some of the proposed CCCTs.

Chief among these options would be incremental demand-side management ("DSM") resources including both EE and DR programs. ELL has already included a modest contribution towards these options in its proposal and could accelerate and expand those resources in lieu of accelerating the generation. Other options would include extending the life of existing resources (*e.g*. renewal of expiring PPAs, extending life of legacy gas, etc.), incremental access to market resources through transmission upgrades, new utility-scale solar and battery storage, and new distributed solar and storage. All of these could potentially be procured within the next 2 years to assist with the Customer's near-term load ramp.

Q. What are some of the advantages of incremental DSM?

A. A well-designed portfolio of DSM resources can provide both energy and capacity value, addressing both the energy consumption and peak demand components of the load in a manner that complements "baseload" supply-side resources and can reduce the need for combined cycle capacity and generation.

EE offers both energy and capacity savings, reducing the total amount of generation needed to serve the load at all hours. The savings from energy efficiency are permanent, but EE is lower cost and does not carry ongoing risks the way CCCTs do. The amount of EE improvements deployed to date in Louisiana is relatively small, meaning there is substantial untapped potential to ramp up with the right level of investment and program design.

DR, on the other hand, is primarily a capacity resource and can help meet the planning reserve margin requirement and ensure resource adequacy during the transitional period until longer-term resources come online.

Q. Is ELL planning to meet a portion of the Customer's needs using DR?

A. [redacted] In addition to direct participation through DR resources that are "on-site" at the data center location, there is also the opportunity to procure DR resources that are "off-site" through general customer participation in DR programs.

Q. Have you evaluated the potential for an alternative portfolio to meet the Customer's load ramp that includes a delayed timeline for constructing the proposed CCCTs?

A. Yes. The figure below provides an illustration of this alternative portfolio and timeline showing the specific firm resource additions through 2033 that can meet the Customer's load ramp. This was developed by using the load ramp from Beauchamp Figure 4 (and underlying data) as a starting point, ELL's existing resources, and additional resources. This load ramp is consistent with the load ramp included in Appendix C of the ESA.[102]

Figure 3: Alternative Portfolio (MW) (HSPM / AEO)

[redacted]

[102] Beauchamp Direct, Exhibit LKB-2 at 87 (HSPM).

Q. What are the key features of this alternative portfolio and timeline?

A. This alternative portfolio timeline includes the following changes:

- A delayed schedule for deploying Richland CC units 1-4 as follows:

Table 9: ELL and NPR Proposed COD

Richland Units	ELL Proposed COD	NPO Proposed COD	Delay
Unit 1	Apr 2030	July 2030	3 months
Unit 2	Apr 2030	Jan 2031	9 months
Unit 3	Nov 2030	May 2031	6 months
Unit 4	Nov 2030	May 2031	6 months

- Pointe Coupee Units 1-3 are not necessary to [redacted]) and are recommended for Commission consideration at a later date (*e.g.*, approval in 2029) as part of the longer-term portfolio.
- Increase in the EE contribution from the proposed $13 million annually (<1% of MMC) to about $91 million annually (5% of MMC). This is estimated to lead to about 385 MW by 2033.
- Continued consideration of [redacted] of the customer's load
- Procurement of 500 MW of incremental "off-site" DR/battery storage
- Continued execution of other planned portfolio resources (*e.g.*, solar + storage), plus consideration of 1-2 year extensions for legacy PPAs

1. Energy Efficiency

Q. Under this alternative portfolio, can you explain the use of EE resources to serve the Customer's load ramp?

A. Yes. ELL has proposed that the Customer contribute a token amount of funding towards its Power to Care and EE programs ($3 million per year and $7 million per year respectively). ELL will match the $3 million annual contribution to Power to Care.[103]

[103] Direct Testimony of Elizabeth C. Ingram at 6, HSPM/AEO Table 1 ("Ingram Direct").

The proposed totals amount to <1% of the MMC revenue collected and thus appear to be more of an afterthought than a serious consideration of EE as a resource option. Instead, ELL and the Customer could consider a larger contribution towards this resource option (*e.g.*, on the order of 5% of MMC revenue). This would support a more robust deployment of EE and demand-side resources that could make a more meaningful contribution towards the Customer's load ramp. Under an alternative portfolio, I estimate that a revenue contribution equal to 5% of the Company's projected MMC could lead to approximately 70 MW/yr of incremental EE resource (or ~385 MW cumulative from 2027 through 2032).[104] While this would not be sufficient to entirely displace the supply-side resource needs, it does contribute towards approximately 9% of the Customer's maximum load and continues to increase beyond that over time.

Q. Can you explain how this investment in EE programs would assist in meeting the Customer's load ramp?

A. Yes. Generally speaking, ELL is responsible for meeting its resource adequacy obligations as a participant in MISO by providing sufficient resources to meet forecasted peak demand in each season. This obligation can be met through a combination of both supply-side and demand-side resources. Whereas supply-side resources contribute additional generation capacity, demand-side resources reduce the Company's peak demand and provide an equivalent reduction in the overall need on ELL's system. Thus, for each 100 MW of DSM resource procured, 100 MW less of CCCT resource is needed. In fact, demand-side resources can have an outsized contribution towards meeting the Company's supply-side need since they reduce the overall Planning Reserve Margin requirements (the needed cushion of available resources over peak demand, as calculated by MISO to meet resource adequacy goals). Thus, investment in EE programs and measures in the Company's service territory is a way to add grid capacity and facilitate new loads coming on to the system. In fact, some large load customers are actively

[104] This estimate is based on data from ELL's most recent EE program year performance (PY11, or calendar year 2025) which showed the annual incremental capacity contribution from ELL's EE portfolio to be 14 MW at a cost of $18.6 million or approximately $1,302/kW. *See* Entergy Louisiana, LLC, Quick Start Energy Efficiency Annual Report – Program Year 11, LPSC Docket No. X-37717 (May 1, 2026).

pursuing this option in other jurisdictions.[105] Expansion of the DSM portfolio could also accommodate novel types of load flexibility programs that could leverage recent technical advancements in distributed batteries, electric vehicle managed charging, and data center flexibility.

Q. Has ELL conducted any recent analysis of its EE savings potential that would support your recommendation?

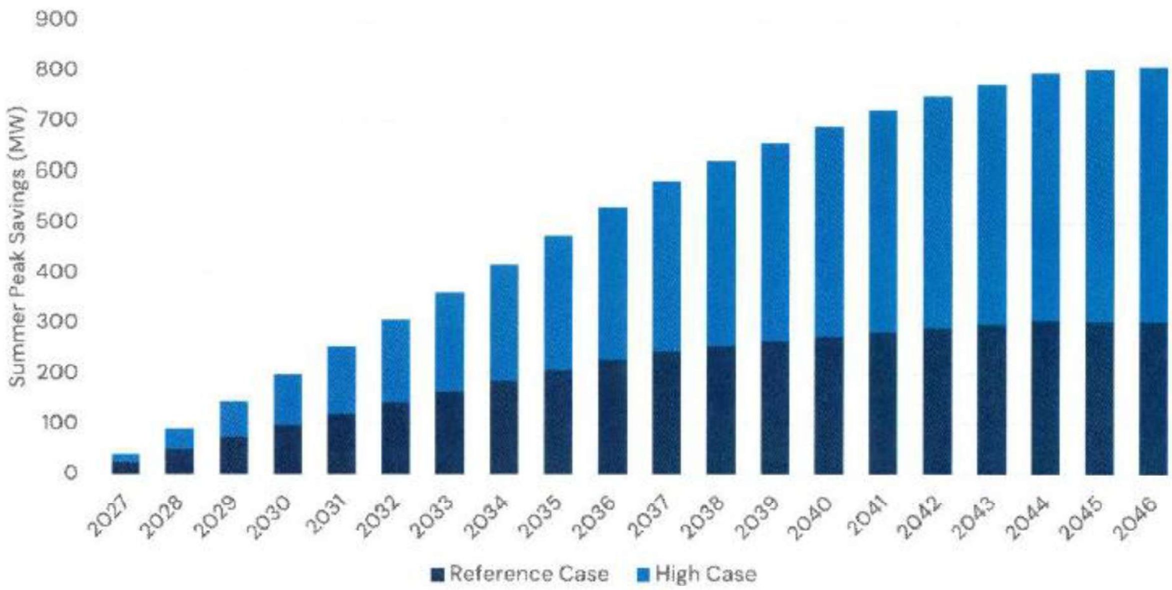
A. Yes. As the Company stated through discovery, "While the full potential study has not been finalized or filed yet, the draft results of the most recent potential study conducted for the Company's ongoing [Integrated Resource Planning] cycle was filed within LPSC Docket U-37764 on April 24, 2026."[106] The draft results are shown below and indicate that between 300-400 MW of EE capacity could be added by 2033.[107] Notably, this is a conservative assumption since both the "Reference Case" and "High Case" are based on achievable potential modeling and do not reflect the full technical or economic potential for EE resources. Moreover, considering the Customer's resources and interest in rapidly obtaining service, contributions towards EE programs from the Customer may not need to be constrained by the same budget limits or cost-effectiveness thresholds that typically bound EE program deployment. Thus, a higher level of EE potential may be feasible than indicated even by the "High Case."

[105] For example, the Kansas Corporation Commission and the Missouri Public Service Commission both adopted a new large load tariff that creates a Clean Energy Choice Rider, which enables customers to directly support the procurement of distributed energy resources, including demand-side management, energy efficiency, and battery storage in exchange for appropriate credit. These tariffs apply to large load customers of Evergy Kansas, Evergy Missouri, and Ameren Missouri.

[106] ELL response to data request NPO 6-6.

[107] Entergy, ELL 2027 IRP – EE, DR, and DER Potential Study Draft Results (Mar. 6, 2026), https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/ViewFile?fileId=a1ECTljfkBI%3d (last accessed July 22, 2026).

Figure 4: Reference and High Case Summer Peak Savings (MW)



Q. Are these EE programs generally more cost effective when compared to supply-side resources such as new CCCTs?

A. Yes. The Company's potential study analysis shows the cost of these EE resources to be on the order of $0.02/kWh, which compares [redacted] Evest LLC Case $/MWh Fuel Cost as shown in Exhibit SD-2 (HSPM/AEO).

2. Demand Response

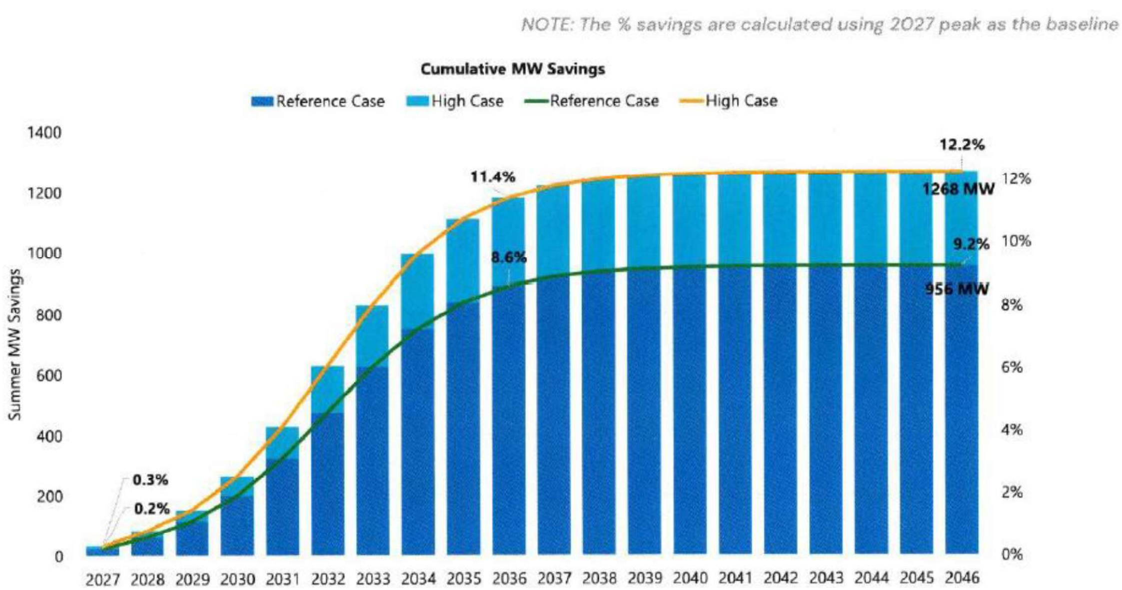
Q. Under this alternative portfolio, can you explain the use of DR resources to serve the Customer's load ramp?

A. Yes. There are two categories of DR resources that would be used to serve the Customer's load. The first category is comparable to ELL's proposal in that ELL [redacted]. My recommended alternative portfolio would similarly [redacted]. The second category of DR resources would be "off-site" DR. This is intended to capture deployment of up to 500 MW of incremental new DR at sites in ELL's service area other than the customer's site by 2031. This could include both "traditional" forms of DR as well as novel forms such as distributed battery storage deployment that has been gaining recent traction in many markets across the US. I selected 2031 as a reasonable time period to allow for competitive procurement of DR capacity resources, including battery storage resources.

Q. Has ELL conducted any recent analysis of its DR savings potential that would support your recommendation?

A. Yes. Similar to the EE results I described above, the Company's draft potential study that was filed in LPSC Docket U-37764 also included results for DR, which are shown below.[108] Notably, these results show potential exceeding 400 MW by 2031 and exceeding 800 MW by 2033.

Figure 5: Summer MW Savings - All Sectors



[108] *Id*.

Q. Are you concerned that these DR resources do not provide "baseload" energy needs?

A. No. I am cognizant that DR resources are primarily designed to serve as a source of firm capacity for resource adequacy reliability and are therefore not intended to provide baseload energy. However, this is by design and not necessarily a source of concern. There are several additional reasons for my lack of concern. First, ELL's own proposed portfolio [redacted]. Second, the Customer load ramp is [redacted]. Third, the Company has not found it necessary to perform any Capacity Expansion modeling that would help illuminate how much of the Company's overall resource needs are driven by capacity limitations versus energy limitations.[109] Fourth, most of the resources included in the alternative portfolio similarly function as a source of baseload energy as well as firm capacity. Fifth, many recent studies have demonstrated that the resource needs in most regions of the grid, including MISO, are driven by a small subset of peak hours. Thus, incremental energy and demand from high-load factor customers can often be accommodated simply by addressing the peak demand needs.[110]

3. Existing Portfolio Resources

Q. Under this alternative portfolio, can you explain the use of existing portfolio resources to serve the Customer's load ramp?

A. Yes. According to the ramp schedule provided in Exhibit RDJ-2 (HSPM/AEO), ELL has identified [redacted] prior to any of the new CC units coming online. Thus, by definition, ELL will be relying upon the remainder of its existing resource portfolio to meet these needs since the CC units will not yet be unavailable. Presumably these existing firm resources will continue to be available to serve the Customer's load until there are significant

[109] ELL response to data request SC 1-3.

[110] Tyler H. Norris et al., *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*, Duke University Nicholas Institute for Energy, Environment & Sustainability (February 2025), https://nicholasinstitute.duke.edu/publications/rethinking-load-growth.

reductions in ELL's existing resource portfolio due to major retirements or PPA expirations. As such, while the alternative portfolio initially includes [redacted] MW of existing firm resources, the alternative portfolio conservatively assumes these portfolio resources will decline to 500 MW in early 2031.

Q. Are there any major retirements or contract expirations for existing portfolio resources in ELL's resource plan prior to 2033 that might affect this?

A. Yes. The most significant reductions to ELL's existing resource portfolio before 2033 are the retirement of Little Gypsy Units 2 & 3 by summer 2030, the retirement of Big Cajun 2 Unit 3 by summer 2031, and the expiration of the Carville PPAs by summer 2032.[111] The coincidence of these planned resource retirements with the Customer's load ramp is likely contributing to ELL's purported need for expediting the addition of seven new CCCTs in the 2030-2032 timeframe, despite the higher cost and risk that acceleration brings. However, ELL's expedited approach becomes unnecessary when planned additions within the Company's existing resource portfolio are considered. For example, new CCCT resources are already slated (as proposed in Docket No. U-37853) to replace the Little Gypsy units. The Company's portfolio also contains a considerable amount of solar and battery storage additions in the 2027-2032 timeframe that will provide MISO-accredited capacity for meeting ELL's resource adequacy needs. Furthermore, it is conceivable that the expiring PPAs could be extended – even doing so for a brief 1-2 year period (*e.g.*, through 2033) could assist in meeting the Customer's load ramp through the near term. This temporary extension would then allow additional time for competitive solicitation for other replacement resource additions in the 2032-2034 timeframe, beyond the limited subset proposed by ELL.

To summarize, the alternative portfolio proposed here assumes that of the 1,236 MW of existing and planned portfolio resources used to serve the Customer in 2030, at

[111] ELL response to data request Staff 1-1, attachment "BP26 and Evest L&Cs HSPM" (Base Case tab, rows 28 and 123; Change Case tab, rows 28 and 131). I note that Entergy's most recent 2027 Integrated Resource Plan Supplemental Data Filing dated April 24, 2026, https://www.entergylouisiana.com/wp-content/uploads/2027-ELL-IRP-Data-Assumptions-Supplemental_2026_04_24_PUBLIC.pdf, at 12, assumes a 2028 deactivation for Big Cajun 2 Unit 3, but I have based my analysis on ELL's workpapers.

least some portion (*i.e.*, approximately 500 MW) would persist through 2033 to meet the Customer's initial load ramp. This could readily be accomplished through the currently planned Little Gypsy replacement and new solar and storage additions, while also being potentially supplemented by a brief 1-2 year extension of expiring PPAs in 2032.

Q. Are there other resources that could potentially serve the Customer by 2033 that you did not fully evaluate, but could be considered for an alternative portfolio?

A. Yes. In particular, I did not evaluate the ability for MISO market resources to serve the Customer. In particular, there may be a significant opportunity for a large portion of the Customer's 8,760-hour energy needs to be served by non-firm generation resources delivered from MISO. In conjunction with this, firm capacity needs could also be met by market resources through targeted upgrades to ELL's transmission system. These firm and non-firm resources could include a variety of underlying assets including both thermal generators and renewables.

Notably, the Company has not evaluated this alternative either: in response to discovery, ELL confirmed that it "has not calculated the potential costs of procuring capacity from the MISO spot market," and that the capacity effect reflected in its economic analysis was instead valued at the levelized real cost of a combustion turbine rather than at the cost of procuring capacity from the market.[112]

Q. Have other NPO witnesses more fully evaluated the transmission-related solutions you briefly mentioned above?

A. Yes. NPO witness Nick Miller provides a more robust analysis of steps ELL could take to overcome transmission barriers as a means to enable resource options other than the proposed CCCTs. I support his recommendations in that regard.

[112] ELL response to NPO data request 5-8(a).

Q. What are the advantages of this alternative near-term resource plan?

A. There are several advantages. First, it will allow additional time for Commission deliberation and prevent a rush to judgment on a $16 billion investment that could pose significant risks to existing customers. Second, it will allow for competitive solicitation of resources in the 2032-2034 timeframe to allow more options to be considered than the limited subset proposed by ELL. Third, it would amplify the local economic impact of the Meta data center by focusing investment on distributed and community resources such as energy efficiency.

VIII. ADDITIONAL STEPS REQUIRED TO MITIGATE COST AND EXECUTION RISK ARE NEEDED (RECOMMENDATIONS SECTION):

Q. Can you summarize your concerns with ELL's proposal?

A. Yes. I am concerned that ELL's proposed $16 billion capital investment poses an extreme risk to existing customers that is not adequately mitigated by the terms of the ESA due to specific gaps that I have described in my testimony. Furthermore, the proposed development timeline poses significant execution risks that are unnecessary and could be avoided if an alternative development timeline and resource plan were pursued instead.

Q. Are there specific actions you recommend that the Commission take to alleviate these concerns?

A. Yes. I have seven core recommendations for the Commission, which are as follows:

- *Recommendation 1: Direct ELL to implement a more staggered implementation schedule for constructing CC units 1 through 7*

Q. Why is Recommendation 1 necessary?

A. Recommendation 1 is necessary to avoid the execution risk of attempting to construct seven CC units in a highly compressed timeframe, as I described in Section VI of my testimony. Additionally, this recommendation would minimize the acuteness of the cost risk to existing customers (described in Section IV) by spreading out the cost incurred over a more reasonable time period. Finally, a staggered approach will more readily allow ELL and the Customer to address any potential [redacted] of the load ramp that may occur as Meta Platforms' newly announced business plan to sell excess compute capacity becomes more fully developed.

Q. Is a more staggered project development timeline feasible while still meeting the Customer's needs?

A. Yes. As I illustrated above in Section VII of my testimony, ELL's proposal would lead to excess capacity in some years that would allow for some delay in the proposed timeline for Units 2 through 7. A more staggered schedule can also be supported by increased deployment of EE and DR resources, which I also recommend.

- *Recommendation 2: Limit immediate PSC approval to Richland Units 1 and 2 ("Group A") and address Richland Units 3-4 ("Group B") and Pointe Coupee Units 1-3 ("Group C") at a later date. For the Units addressed later, the MBM should be applied.*

Q. Why is Recommendation 2 necessary?

A. Recommendation 2 complements Recommendation 1 and is necessary to limit unnecessary cost risk to existing customers. ELL requests approval of all seven units immediately; however, the pursuit of a staggered implementation schedule as described in Recommendation 1 will allow for a staggered PSC approval process while still allowing for sufficient time for project development of each individual unit (as illustrated in Table 7 above). A staggered approval process is preferable for a number of reasons including the following: It would ensure that less overall cost and risk was at stake in any one individual decision that the Commission must make in the near term. It would also have the advantage of giving the Commission additional flexibility to modify its approach if it turns out that the load forecast was different than initially anticipated in Meta's [redacted] projection. It would more appropriately balance the needs of the Customer with both risks to existing customers and execution risks. Finally, it would allow for other more competitive resource options to be considered. As such, I further recommend that the full MBM be applied to Units 2 through 7, rather than waived as ELL has proposed.

- *Recommendation 3: The PSC should ensure ELL does not unfairly shift risk from shareholders to existing customers through the election of Retained Generator status upon termination. Approval of Retained Generator status should follow the decision process outlined in Section V-A above.*

Q. Why is Recommendation 3 necessary?

A. While the proposed ESA contains many provisions intended to mitigate risks to existing customers, it currently includes a significant gap. More specifically, if ELL elects Retained Generator status upon termination, it can effectively bypass many of the ESA provisions intended to protect existing customers through the liquidation process. In this circumstance, neither Meta nor ELL shareholders would be responsible for bearing the risks associated with the $16 billion investment as these costs would instead be passed on to existing ELL customers through retail rates. To help resolve this, the Commission should follow the decision tree process outlined in Section V-A of my testimony when considering approval of a request for Retained Generator status. Additionally, the Commission should take further action as I've described below in Recommendation 4 to establish criteria for approving cost recovery of a Retained Generator well in advance of any such requests.

- *Recommendation 4: If Retained Generator status is elected and approved upon early termination, the net plant for such generators should be ineligible for general cost recovery until the end of the original 20-year ESA term, and other specific Commission-established criteria are met.*

Q. Why is Recommendation 4 necessary?

A. Consistent with Recommendation 3, Recommendation 4 is necessary to ensure that existing customers are not unfairly exposed to higher cost risks due to gaps in the proposed ESA structure. This step would properly shield existing customers from the risk that the Customer's load does not fully materialize and ensure that existing customers do not pay higher costs in such case. In the event of an ESA termination or [redacted], existing customers would not have caused the incremental costs initially meant to serve the Customer and therefore they should not be responsible for paying these costs. ELL has not articulated any criteria which would determine whether paying these additional costs could be considered beneficial to existing customers. This should never be assumed, even if ELL asserts that the remaining costs should have Retained Generator status.

By excluding the remaining net plant from general cost recovery until the end of the original 20-year ESA contract term, this will ensure that existing customers do not pay more than they otherwise would have due to the Customer's projected load impacts.

It would also ensure that ELL shareholders, not just existing customers, assume some risk in executing the ESA with Evest. Moreover, the Commission should establish in advance any other evaluation criteria it will use for approving Retained Generator status, including a clear methodology for calculating net benefits to customers.

In any case, it is appropriate that ELL shareholders bear some meaningful portion of this risk since they are the sole beneficiaries of the return on invested capital at stake. By making sure that the Retained Generator pathway does not serve as a "get out of jail free card," this Recommendation will also help motivate ELL's management to hold Meta accountable to its promises upon termination. This includes ensuring that Meta maintains sufficient collateral and insurance coverage to mitigate the risk of stranded cost. If ELL is simply able to pass those costs on to its customers, it may not have the same motivation to seek this accountability from Meta.

Recommendation 5: The PSC should require ELL to seek stronger collateral and insurance requirements beyond the proposed levels, including requiring [redacted] *equal to a minimum of 50% of the remaining net plant.*

Q. Why is Recommendation 5 necessary?

A. As explained in my testimony, the Commission should be extremely cautious about relying upon the Meta parent guaranty as a form of collateral. Meanwhile, the remaining [redacted] and insurance coverage are insufficient to fully protect ELL customers and/or shareholders in the event that these financial securities are called upon. As ELL has testified, the insurance market is currently unable to provide protection above $[redacted]. Thus, the only remaining remedy would be to increase the [redacted] requirement. I recommend this requirement be increased to match 50% of the remaining net plant at any given time. This will complement the insurance coverage which is expected to cover the other 50% portion.

Recommendation 6: The PSC should direct ELL to develop a cost allocation approach designed to ensure that the benefits from the Customer's revenue are broadly shared.

Q. Why is Recommendation 6 necessary?

A. While ELL has asserted that the ESA will provide net benefits to its customer base, it is not a certainty that all customers will benefit from the proposed approach. There may be barriers (perhaps unintended) to sharing the benefits due to existing approaches to cost allocation. Absent any changes from typical cost allocation schemes, the benefits are likely to be primarily retained by the industrial customer class and not shared with other classes (e.g. residential). Thus, the PSC should verify that the benefits are widely shared as ELL appears to want, it is also necessary to ensure the relevant cost allocation scheme supports this outcome. This verification step could be accomplished through an updated cost of service study showing how both the costs and benefits of the ESA flow through to each customer class. The PSC should require ELL to produce such a study and identify any future changes to its cost allocators necessary to share the benefits more fairly.

Recommendation 7: In the event of non-renewal at the end of the ESA term, retail rate recovery of the remaining Net Plant will be capped based on net plant value of $2 billion starting in 2048 if determined to be used and useful by the Commission.

Q. Why is Recommendation 7 necessary?

A. ELL's analysis presumes that the ESA contract will be renewed at the end of its term. However, this is not a certainty and the chance of non-renewal represents a real risk that ELL is seeking to pass on to its captive customers. As such, this recommendation is necessary to ensure that ELL fairly shares in the risk of non-renewal and is not able to pass on 100% of this risk. I estimate that setting a cap based on net plant value of $[redacted] would [redacted] sharing of risk, assuming [redacted] Net Plant remains in 2048 consistent with ELL's estimates. Additionally, the Commission must evaluate the used and useful status of any ESA generating asset proposed for cost recovery at that time.

Q. Does this conclude your testimony?

A. Yes.

STATE OF LOUISIANA

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

IN RE*: APPLICATION FOR APPROVAL OF GENERATION AND TRANSMISSION RESOURCES AND FOR OTHER RELIEF PURSUANT TO THE COMMISSION'S *LIGHTNING INITIATIVE	))))))))	**DOCKET NO. U-37882**

State of Oregon)
County of Multnomah)

AFFIDAVIT

I, Edward Burgess, being first duly sworn, deposes and says that I am the same Edward Burgess whose Direct Testimony accompanies this affidavit; that such testimony was prepared by me; that I am familiar with the contents thereof; that the facts set forth therein are true and correct to the best of my knowledge, information and belief; and that I adopt the same as my sworn testimony in this proceeding.

Edward A. Burgess

Edward Burgess

Sworn to and subscribed before me on this 22 day of July, 2026, in Portland, OR.

OFFICIAL STAMP
VALERIE IO NOVA
NOTARY PUBLIC - OREGON
COMMISSION NO. 1045458
MY COMMISSION EXPIRES FEBRUARY 20, 2028

Valerie Nova

NOTARY PUBLIC

My commission expires: 02/20/2028

Docket No. U-37882

Exhibit EB-1

ELL Response to AAE 1-4 (Public)
ELL Response to NPO 5-5
ELL Response to Staff 1-17 (Public)
ELL Response to Staff 1-34 (Public)
ELL Response to NPO 3-18
ELL Response to NPO 3-19
ELL Response to SREA 1-2
ELL Response to NPO 7-2
ELL Response to NPO 3-16
ELL Response to NPO 5-23
ELL Response to AAE 1-3
ELL Response to Staff 1-92
ELL Response to NPO 7-1
ELL Response to Staff 1-30
ELL Response to Staff 1-45
ELL Response to Staff 1-146 (Public)
ELL Response to Staff 1-151 (Public)
ELL Response to NPO 6-6
ELL Response to SIERRA 1-3
ELL Response to NPO 5-8

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: AAE 1-4 Part No.: Addendum:

Question:

Re: Direct Testimony of Goin at Questions 14-19 (pages 9-13):

a. Please provide ELL's estimate of the price for firm gas transportation capacity to serve the gas needs of Richland Units 1, 2, 3, and 4 (individually and/or collectively). Please provide all records, documents, communications, data, and analyses to support your response.

b. Please provide ELL's estimate of the price for firm gas transportation capacity to serve the gas needs of Pointe Coupee Units 1-3 (individually and/or collectively). Please provide all records, documents, communications, data, and analyses to support your response.

c. Will the construction of a new gas pipeline to serve Pointe Coupee Units 1-3, as discussed by Mr. Goin on page 11, require approval by the Federal Energy Regulatory Commission under the Natural Gas Act? Please explain.

d. If the answer to part (c) is Yes, please describe the Company's expected timeline for obtaining FERC approval.

e. Is the Company's 20-year firm gas transportation agreement with Energy Transfer LP, announced in November 2025 (https://www.entergy.com/news/entergy-louisiana-and-energy-transfer-sign-agreement-that-supports-reliable-affordable-energy-and-economic-growth-in-north-louisiana), intended to serve the needs of Richland Units 1-4 and/or Pointe Coupee Units 1-3? Please explain.

f. Please provide the expected firm gas transportation charge to be paid by ELL each year of the 20-year agreement with Energy Transfer LP, referenced in part (e).

g. How will the costs referenced in parts (a) and (b), once actually realized, be recovered from the Customer or otherwise from the general customer base, under ELL's proposal in this matter? Please provide pinpoint citations to supporting references in direct testimony.

h. How have the cost estimates referenced in parts (a) and (b) been considered in ELL's planning toward procuring particular resources to serve the Customer? Please provide pinpoint citations to supporting references in direct testimony.

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving the objections, the Company responds as follows.

a. See the Company's response to Staff 1-33.

b. See the Company's response to Staff 1-17.

c. The Company objects to this request to the extent it seeks a legal conclusion. Subject to and without waiving the foregoing, the Company continues to review the current proposals discussed in the Direct Testimony of Michael J. Goin. At this time a final selection has not been made and the relevant regulatory approvals for any potential proposed solution have not been determined by the Company.

d. See the response to subpart (c).

e. No, the November 2025 agreement with Entergy Transfer LP is not intended to provide primary service to any of the Proposed Generators. However, that service provided by that agreement may also be able to provide service to Richland Units 1-4.

f. ELL will pay approximately [redacted] to Energy Transfer LP for the Firm Transportation contract referenced in subpart (e).

g. Firm gas transportation costs would be recovered through ELL's monthly FAC. See also the Company's response to Staff 1-17.

h. The Company objects to this request as vague and ambiguous, particularly the use of the term "particular resources." The Company further objects to this request as it mischaracterizes or misstates the testimony on file. The Proposed Generators are not sought to directly serve the Customer; rather, the Proposed Generators are intended to be system resources that enable service to the Customer through ELL's electric system. Subject to and without waiving these objections, the Company responds as follows: Resource selection and siting decisions are made utilizing a number of factors, including the availability and cost to utilize natural gas. Once a resource selection and siting decision has been made, ELL solicits bids from multiple vendors in order to secure the best firm gas transportation rates.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: AAE 5-5 Part No.: Addendum:

Question:

Has ELL developed sensitivity analyses (a) showing the impact on the "Total Customer Impact" ("TCI") of load materializing at levels below the projected maximum demand or load factor? If so, please provide those analyses, and (b) estimating at what load materialization level the TCI would become negative (i.e., existing customers are net worse off)? If yes, please provide the analyses, workpapers, and results. If not, please explain why ELL did not conduct such analyses.

Response:

ELL incorporates in full the General Objections served with these Requests. The Company further objects to this request to the extent it seeks analyses that have not previously been performed by the Company. Subject to and without waiving the objections, the Company responds as follows.

No, such analysis has not been performed. Company witness Ryan D. Jones's assumption of the metered kWh used in his rate analysis, which was an input into Company witness Samrat Datta's economic analysis and the computation of the "Total Customer Impact" ("TCI") metric, is based on the best information received from the Customer. The Company remains confident in this assumption as a reasonable estimate of the Customer's energy consumption.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: STAFF 1-17 Part No.: Addendum:

Question:

Regarding Exhibit SD-2 "**Recovered Fixed Fuel Demand**", please:

a. Provide narrative support for each year's [redacted]. In providing this response include a narrative description of all inputs and assumptions used in the derivation of this [redacted]. Provide the exact formula used to derive each annual amount and reconcile that formula numerically to the values shown in Exhibit SD-2.

b. Additionally provide a method by which the Commission can review future actuals to compare against this projected benefit.

Response:

The Company objects to the "Instructions" included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the directive that "these requests are continuing so as to require supplemental responses" as such directive seeks to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material ("HSPM") and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

a. The fixed fuel demand charges that will be incurred for the reservation of natural gas pipeline capacity for gas-fired power plants will be recovered in two ways: a portion of the fixed fuel demand charges (approximately equal to the proportion of the total fixed fuel demand charges that correspond to the power plant's capacity factor[3]) are embedded in the power plant's offer price into the energy market, and are thereby recovered through energy margins in the wholesale electricity market; the remainder will be recovered through the Fuel Adjustment Clause ("FAC"). While an estimate of such fixed fuel demand charges is included in the generation cost input assumptions of the Aurora production cost model, such costs are excluded from the reporting of the variable supply cost output from the production cost simulation. Hence, the economic analysis performed by Company witness Mr. Datta included such fixed fuel demand charges separately (from the variable cost change resulting from the Evest LLC load and resources) in the cost section of HSPM-AEO Exhibit SD-2, but also accounted for the recovery of such costs from the Customer.

The "Evest LLC + Laidley LLC - Recovered Fixed Fuel Demand - Evest Resources" represents the estimated payments made by the Evest LLC and the Laidley LLC customer towards the fixed fuel demand charges associated with the seven combined cycle resources that constitute the Evest Proposed Generators portfolio. These estimated payments towards the fixed fuel demand charge associated with the seven combined cycle Proposed Generators by both Laidley LLC and Evest LLC are equal to their load ratio share of the ELL system coincident peak load multiplied by the forecasted fixed pipeline transportation rate of $[redacted]/MMBTU/yr for the Richland Parish units 1 – 4 and $[redacted]/MMBTU/yr for the Point Coupee units 1-3 combined cycle power plants multiplied by the assumed reserved pipeline capacity of [redacted] MMBTU/day for each of the seven CCCTs. The economic analysis incorporated both Evest LLC and Laidley LLC's fuel contributions towards the fixed fuel demand charge since the TCI metric computes the impact of the Evest LLC load and resources on ELL's other customers not including the parent corporation of both Laidley LLC and Evest LLC. Please also see the spreadsheet version of HSPM-AEO Exhibit SD-2.

b. See the Company's response to subpart (b) of Staff 1-4.

[3] The fixed fuel demand charges are spread across the volume of natural gas that corresponds to a capacity factor of the power plant of 100%; since any gas-fired power plant runs at less than 100% capacity factor, the remainder of the fixed fuel demand charge is recovered through the FAC

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: STAFF 1-34 Part No.: Addendum:

Question:

Regarding Exhibit SD-2 "**Fixed Fuel Demand**", please:

a. Provide narrative support for annual amount included in the 3 "Point Coupee" units line items. In providing this response include a narrative description of all inputs and assumptions used in the calculation or derivation of the annual amounts.

b. Does the amount on Exhibit SD-2 in corporate the projected costs of the additional pipeline that ELL states needs to be built to serve the 3 Point Coupee Units. If it does not, why not?

c. Explain why the amounts are presumed not to change for the entire life of the ESA.

d. Confirm that ELL will be able to provide the actual Fixed Fuel Demand expenditures for the Commission to be able to compare to these projected Fuel Fixed Demand expenditures or if such cannot be confirmed explain why.

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the directive that “these requests are continuing so as to require supplemental responses” as such directive seeks to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material (“HSPM”) and will be produced only to the appropriate Reviewing

Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

a. The fixed fuel demand charges for the Point Coupee units 1-3 are estimated firm transportation charges associated with securing firm pipeline capacity to those generators. The Company has estimated gas usage at [redacted] MMBTU/day each for these three units and the firm transportation rate at [redacted]/MMBTU/year for the duration of the gas pipeline contract. Please see rows 103 – 115 in the "Data Library" tab of the Excel version of HSPM-AEO Exhibit SD-2 provided in the Company's response to Staff 1-1.

b. The cost to build the additional pipeline to serve the Point Coupee units will not be directly borne by ELL. It is presumed that to the extent such costs are recouped from ELL, they are included in the firm transportation rate, mentioned in subpart a above, and recovered through the Fuel Adjustment Clause.

c. In securing long-term firm pipeline capacity, the Company expects the firm gas transportation charges to remain fixed through the life of the pipeline contract; hence, such costs are assumed to remain unchanged for the life of the pipeline contract, which subsumes the Original Term of the ESA

d. The Company objects to subpart (d) of the request as it constitutes requests for admission in contravention to Rule 63 of the Commission's Rules of Practice and Procedure. Subject to and without waiving the objections, please see the response to subpart (b) of Staff 1-4.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: AAE 3-18 Part No.: Addendum:

Question:

Please refer to the Direct Testimony of Mr. Owens at Q13 (pages 9-10), stating: "the analysis uses conservative estimates of incremental capacity needs arising from the Customer load addition. With less conservative assumptions, the proposed portfolio could provide substantially more capacity than necessary to address incremental capacity needs, and that would translate to higher benefits than have been incorporated in the cost-benefit analysis":

Please define how surplus capacity relative to Entergy retail load needs would constitute a benefit. Who would benefit, and how is the benefit calculated? Please be specific.

Response:

ELL incorporates in full the General Objections served with these Requests. ELL further objects to the request as vague and overbroad to the extent the request generally requests specificity. ELL has no obligation beyond providing a direct response to the questions posed in the request. Subject to these objections, ELL responds that potential surplus capacity relative to the ELL retail load represents a benefit to ELL retail customers because surplus capacity could either be sold or used to displace resource additions that would otherwise be needed. See the Direct Testimony of Nicholas W. Ownes at page 11. Regarding the calculation of the benefit, the analysis uses conservative estimates of incremental capacity needs. See Owens Direct Testimony at pages 8-9. The net change in ELL's capacity position is valued in the analysis using the levelized cost of a combustion turbine. See the Direct Testimony of Samrat Datta at page 21.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: AAE 3-19 Part No.: Addendum:

Question:

Please refer to the Direct Testimony of Mr. Owens at Q15 (page 11), stating that there is "an upside opportunity for ELL's customers in the form of potential surplus capacity that can either can be sold or used to displace resource additions that would otherwise be needed":

a. How has ELL estimated the future market value of the potential surplus capacity? Please be specific.

b. How has ELL estimated the probability of the need for future resource additions of the type represented by the Proposed Generators? Please be specific.

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving the objections, the Company responds as follows.

a. See the Company's response to AAE 3-18.

b. The Company objects to subpart (b) of the request to the extent that the request calls for speculation. Subject to and without waiving this objection, the Company responds that planning for future resource additions is not undertaken using a single static probability score as requested in the request. ELL has not estimated such a probability.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Southern Renewable
Energy Association

Question No.: SREA 1-2 Part No.: Addendum:

Question:

In reference to bill and rate impacts on the Company's other customers resulting from the proposal in the Company's Application, please respond to the following:

a. Has the Company conducted a cost-of-service story or other rate impact analysis to quantify the impact on customer classes and the average residential customer? If so, please provide the study or analyses, including in spreadsheet format with all formulas intact. If not, please explain why such a study or analyses has not been conducted, and provide all available information on rate impacts to other customers.

b. In reference to Section XIII of the Application, at page 18, which states "ELL accordingly asks that the Commission find that the Proposed Generators are system resources…" and paragraph 3 under Application Section XXVIII, at pages 27-28, please confirm that the costs of the generators and the battery storage facilities would be allocated to all customer classes if the Company's request is granted by the Commission. If the response is anything other than an unqualified affirmative, please explain in detail.

c. In reference to paragraph 3 under Application Section XXVIII, at pages 27-28, which states "that the fuel costs of the Proposed Generators and the costs of the energy to charge the Battery Storage Facilities is deemed eligible for recovery via the FAC", please confirm these costs would be allocated to all customer classes if the Company's request is granted by the Commission. If the response is anything other than an unqualified affirmative, please explain in detail.

Response:

a. ELL has not prepared any specific "cost-of-service story" or rate impact studies for individual customer classes. Instead, through testimony and the production of supporting exhibits, ELL has focused on the broader effects of this project on customers in general that would be realized through existing rate and cost allocation mechanisms. Please see the supporting workpapers on Exhibits RDJ-2 and SD-2 produced in response to Staff 1-1.

b. Yes, the referenced generation costs would be recoverable following LPSC approval just like any other system resource. However, revenues generated through providing service to the Customer or through minimum monthly charges would offset the revenue requirement such that there would be no effect on rates when the system resources are placed in service, thereby minimizing or nullifying the effect of this service on all other customers once operations have commenced.

c. Yes, fuel costs of the proposed generators would be recoverable from all ELL customers, which includes the Customer, just as the fuel costs associated with the other generators on the ELL system are recoverable from all ELL customers, which includes the Customer.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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 provide an explanation for how revenue from Evest LLC will be allocated to Entergy's overall revenue requirements.

a. For example, will all Evest-associated revenue equal to the "incremental revenue requirement of the resources being developed in connection with serving the Customer" (ref.: direct testimony of Jones at 23:6-7) be applied to base rate revenue requirements across all customer classes to reduce such classes' base rate obligations? If so, by what methodology?

b. Will the excess revenue from Evest of (as projected) "more than $1.27 billion over the term of the ESA" (ref.: direct testimony of Jones at 23:8) above the revenue requirement referenced in part (a) be applied to base rate revenue requirements across all customer classes to reduce such classes' base rate obligations? If so, by what methodology?

c. For storm cost riders and Resilience Program riders, will Evest-associated revenues be applied across all customer classes to reduce such classes' rider obligations? If so, by what methodology?

d. Is Entergy proposing to re-set base rates to ensure equitable distribution of Evest revenues across all rate classes? Please explain in detail.

Response:

ELL incorporates in full the General Objections served with these Requests. The Company further objects to subpart (d) on the grounds that it is vague and ambiguous, particularly with respect to the meaning of the term "re-set base rates to ensure equitable distribution." Subject to and without waiving these objections, the Company responds as follows:

a. The manner in which Evest-associated base and FRP revenue will be treated for ratemaking purposes is described in detail in the Deferral Proposal Framework provided in Exhibit RDJ-4. As described therein and in the

Direct Testimony of Ryan D. Jones, Evest-associated revenue will be used to offset the rate effects of the incremental revenue requirements in and through the same mechanisms through which the cost of the investment is eligible to be recovered.

b. Excess revenue from Evest, referred to by Company witness Ryan D. Jones as “FRP Margin,” will be included in annual Formula Rate Plan Evaluation Reports as FRP Revenues that, pursuant to Section 2.C.3. of Rider Schedule FRP, are allocated as a percentage of Base Rate Revenue for all eligible retail rate classes. See also Exhibit RDJ-4.

c. See responses to Questions 31-34 of the Direct Testimony of Ryan D. Jones.

d. See the response to subpart (a).

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: AAE 3-16 Part No.: Addendum:

Question:

Did ELL contract with an Independent Monitor to monitor the resource selection process that led ELL to selecting the Generation Assets it is proposing in this application? If not, why not? If yes, please explain the role of the Independent Monitor in this process.

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving the objections, the Company responds as follows.

No. As discussed in ELL Witness Ryan Jones's Direct Testimony (pages 55-56), under the LPSC Lightning Initiative, the requirements of the MBM Order (including the provisions for an Independent Monitor) may be waived where certain factors are met. Mr. Jones' testimony further explains why ELL's application meets these factors.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: AAE 5-23 Part No.: Addendum:

Question:

Please describe any analyses ELL performed regarding whether certification and construction of the Proposed Generators could be phased or staged pending demonstrated load materialization.

Response:

ELL incorporates in full the General Objections served with these Requests. The Company further objects to this request to the extent it seeks attorney work product, attorney client communications or otherwise protected materials. Subject to and without waiving the objections, the Company responds as follows.

Common issues bind the certification of each of the Proposed Generators, and phasing or staging certification of the Proposed Generators would be inefficient and overburden the resources of the Commission, Commission Staff, the Company and intervenors and needlessly delay resolution of this matter.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: AAE 1-3 Part No.: Addendum:

Question:

Re: Meta Guaranty discussed in Direct Testimony of Hinkson and Direct Testimony of Kidd.

a. Please provide a copy of the Meta Guaranty.

b. Are the "ESA Guaranty" and "Meta Guaranty" as discussed by Mr. Kidd the same instrument?

c. Please provide all information, records, correspondence, or documents that the Company has obtained regarding the location, amount, and/or nature of financial, physical, and intangible assets held by Meta Platforms, Inc.

d. Please provide plans the Company has developed to pursue legal action to enforce the Meta Guaranty if necessary. In addition to providing such plans, please answer:

    i. In which jurisdiction would ELL first seek to enforce the Meta Guaranty?

    ii. In which jurisdiction would ELL next seek to enforce the Meta Guaranty after the first jurisdiction referenced in part (d)(i)?

e. Please provide all information, records, correspondence, or documents that the Company has obtained regarding other guaranties that Meta Platforms, Inc. has made to other electric utilities.

f. Please provide any comparison of the Meta Guaranty in this proceeding to the Meta Guaranty in Docket No. U-37425.

g. Please provide any legal opinions which discuss the enforceability of the Meta Guaranty at issue in this proceeding.

Question No.: AAE 1-3 Part No.: Addendum:

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving the objections, the Company responds as follows.

a. See HSPM-AEO Exhibit LKB-2 at pages 119 through 123.

b. See the Company's response to Staff 1-90.

c. The Company has relied upon the public filings of Meta Platforms, Inc. that are equally accessible to the requestor. See, among other things, Meta Platforms, Inc.'s public filings with the Securities and Exchange Commission.

d. The Company objects to this request as it improperly seeks the disclosure of the Company's privileged legal strategy. Furthermore, the Company objects to this request as it presents an incomplete hypothetical and requires speculation regarding an event that has not and may never happen.

e. No responsive documents.

f. The Company objects to this request to the extent it seeks documents that are irrelevant and not reasonably calculated to lead to the discovery of admissible evidence. The Company further objects to this request to the extent it seeks documents protected from disclosure as attorney work product or attorney client communication. The Company also objects to the request as vague and ambiguous.

g. The Company objects to this request to the extent it seeks production of documents which are protected from discovery pursuant to Louisiana Code of Civil Procedure article 1425(D)(2). The Company further objects to this request to the extent it seeks information or documentation that is protected from disclosure by the attorney-client privilege and/or the attorney work product doctrine. Subject to and without waiving these objections, the Company has no such document in its possession, custody, or control.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: STAFF 1-92 Part No.: Addendum:

Question:

When will the Credit Default Security vehicle(s) need to first be acquired? What will the term on initial Credit Default Security vehicles be? Will there need to be continuous acquisitions? ls there any provision for what will be done if the products needed are not available?

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the directive that “these requests are continuing so as to require supplemental responses” as such directive seeks to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. Subject to and without waiving the objections, the Company responds as follows.

The Credit Default Security (“CDS”) will be acquired no later than the service commencement date, which is expected in 2028. The exact acquisition date has not yet been determined. ELL anticipates that the initial term for the CDS will range from 3 to 5 years and that the CDS will be extended or, as reasonably prudent, replaced by other comparable CDS to maintain continuous coverage. ELL has confirmed that the products currently contemplated for the CDS are generally available. ELL will source alternative products with substantially similar protections if market conditions change.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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:

Regarding the required year-by-year amounts of Credit Default Security described in testimony by Mr. Hinkson at page 14, lines 16-17: Is it Entergy's expectation that Meta or Evest will make a one-time premium payment to pay the third-party insurer prior to 2028 to contractually lock in all the years of Credit Default Security coverage shown in the cited testimony? Or is it Entergy's expectation that Meta or Evest would make a new premium payment each year (or at some other time interval) for remittance to the third-party insurer for Credit Default Security coverage in that given year (or the other respective time interval)?

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving these objections, the Company responds as follows:

Neither scenario is a correct description of the Company's expectation. Any estimated Credit Default Security premiums are contemplated to be recouped by the Company as a component of the costs that are used to determine the Customer's MMC. ELL expects that premium payments will be annual.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: STAFF 1-30 Part No.: Addendum:

Question:

Regarding Exhibit SD-2 "**Evest LLC (ESA) Costs**", please:

a. Provide narrative support for each years amount included in the "Credit Insurance Premiums". In providing this response include a narrative description of all inputs and assumptions used in the calculation of each years' amounts included in the "Credit Insurance Premiums" line item.

b. Confirm that ELL will be able to provide the actual Credit Insurance Premium expenditures for the Commission to be able to compare to the projected Credit Insurance Premium expenditures or if such cannot be confirmed explain why.

Response:

The Company objects to the "Instructions" included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the directive that "these requests are continuing so as to require supplemental responses" as such directive seeks to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. Subject to and without waiving the objections, the Company responds as follows.

a. Please see the Direct Testimony of Kenroy Hinkson Questions 19 through 22 for a narrative description of the Credit Default Security referenced in this proceeding. The amounts reported under 'Credit Insurance Premiums' reflect an estimated total cost associated with the anticipated premiums for the Credit Default Security products that was levelized for purposes of the negotiations with the Customer. As described in the Company's response to Staff 1-92, the Company will procure the first Credit Default Security no later than the service commencement date, which is expected in 2028. The actual cost of the premium associated with the Credit Default Security will depend on a variety of market factors at the time such Credit Default Security is acquired.

b. The Company objects to subpart (b) the request as it constitutes requests for admission in contravention to Rule 63 of the Commission's Rules of Practice and Procedure. Subject to and without waiving the objection, the Company responses as follows.

Please see the response to subpart (f) of Staff 1-25. Further, the Company has proposed to report, and to offset in rates, such amounts under its Deferral Proposal Framework provided as Exhibit RDJ-4.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: STAFF 1-45 Part No.: Addendum:

Question:

Regarding the Minimum Monthly Charge (MMC) described by Ryan Jones and the Exhibit SD-2 line item "**Credit Insurance Premiums**", please address the following:

a. Is the MMC designed to be derived in a manner that will account for all of the annual amounts presented in Exhibit SD-2 for the line Credit Insurance Premiums?

b. If there are any portion of these annual amounts that are not to be included in the MMC, please separately provide the annual amounts from Exhibit SD-2 that are to be included in the MMC and the amounts that are not to be included in the MMC.

c. For any portion of these costs not to be included in the MMC, explain why they are not being included.

d. For any portion of these costs that are to be included in the MMC, narratively explain how the varying annual amounts associated with the costs of the Credit Insurance Premiums will be incorporated into the MMC that will be applied to each monthly bill.

e. If the actual cost of the Credit Insurance Premiums used to derive the amounts included in this line of costs comes in more expensive or less expensive than the amounts used for Exhibit SD-2 will the amounts to be included in the MMC be trued up to reflect actuals?

f. If there is such a true up to actuals, when is the first opportunity for that first true-up to happen and how often may such a true up occur?

g. Provide all calculations supporting the inclusion or exclusion of such costs in the MMC in Excel format with formulas intact.

Question No.: STAFF 1-45

Response:

The Company objects to the "Instructions" included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the directive that "these requests are continuing so as to require supplemental responses" as such directive seeks to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. Subject to and without waiving the objections, the Company responds as follows.

a-d. Yes, in general the MMC was derived to fully offset these costs. Please see Exhibit RDJ-2. The MMC was established based on the calculations in that Exhibit, and the inputs for this cost category that are part of that calculation are displayed there.

e-f. No, Credit Insurance Premium costs are not subject to true up.

g. See response to subparts (a) through (d) above.

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

Question No.: STAFF 1-146 Part No.: Addendum:

Question:

On page 22 of the Direct Testimony of Norman Grunden, it states "The Non-EPC Costs are not fixed" and "other factors such as changes in scope... escalation... labor... or changes in law could affect EPC Costs." Further, on page 14, lines it states: "ELL intends to negotiate a fixed price (with certain exceptions)... EPC contract...":

Please quantify the extent to which the total project cost is subject to cost uncertainty. In providing this response:

a. Identify the total estimated project cost that is:

iv. Fixed under the EPC contract;

v. Subject to escalation or adjustment under the EPC contract; and

vi. Not subject to the EPC contract (Non-EPC Costs);

b. For each category above, provide the percentage of total project cost;

c. Identify the specific cost categories within Non-EPC Costs that are subject to escalation or variability.

Response:

The Company objects to the “Instructions” included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the directive that “these requests are continuing so as to require supplemental responses” as such directive seeks to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material ("HSPM") and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

The EPC pricing for the Richland Parish Units 1 and 2 is based on a negotiated EPC Contract that was executed in February 2026 following an open book estimating process with the EPC partners; TSL and Mitsubishi. The EPC pricing for Richland Parish Units 3 and 4, and Pointe Coupee Units 1-3, are estimates based off of the contracted price for Richland Parish Units 1 and 2 with escalation to planned contract dates for each project and include an additional allowance for site-specific conditions like risks like hydrogeology.

a. The EPC contract for Units 1-2 (Richland Parish 1-2) is a fixed price contract with a true-up mechanism that is capped and intended to mitigate market escalation. Details of this mechanism are discussed in Exhibit B-7 of the EPC contract (provided as an HSPM attachment). Units 3-4 (Richland Parish 3-4), and Units 5-7 (Pointe Coupee Units 1-3), will follow this form of contract when eventually executed.

The breakdown of the EPC costs for Units 1-2 (Richland Parish 1-2) that are fixed and subject to escalation are shown below.

Category	Estimated Cost (M)	Percentage of Total Project Cost (%)
EPC Costs		
Mitsubishi (PIE)	[redacted]	
Fixed		
Subject to Escalation (Transportation)		
Transportation True-Up		
JV / TSL		

Fixed	[redacted]
Subject to Escalation (Equipment & Craft Wages)	
EPC Contract Tax	
EPC Total Contract Price	
Non-EPC Costs	
Total Project Cost	**$3,487**

b. See the Company's response to subpart (a) above.

c. See the Company's response and objections to Staff 1-147, which are incorporated herein.

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

Question No.: STAFF 1-151 Part No.: Addendum:

Question:

On page 4 of the Direct Testimony of Norman Grunden, lines 11-14, it states: " Each CCCT unit… consist[s] of one Mitsubishi Power Americas… CT… one Nooter Eriksen HRSG… and one MPA ('STG')…". Further, on page 28 of the Direct Testimony of Norman Grunden, lines 15-18, it states: "ELL leveraged ETI's competitive solicitation for Power Island Equipment ('PIE')…".

Please provide a detailed breakdown of the costs associated with the Power Island Equipment ("PIE") for the Proposed Generators. In providing this response:

a. Provide the total and per-unit cost for each of the following components:

   v. Combustion turbine (CT) supplied by Mitsubishi Power Americas;

   vi. Steam turbine generator (STG) supplied by Mitsubishi Power Americas;

   vii. Heat Recovery Steam Generator (HRSG) supplied by Nooter Eriksen;

   viii. Any other major equipment included within the PIE scope;

b. For each component identified in part (a), state whether the pricing was:

   iv. Established through the PIE competitive solicitation referenced above;

   v. Derived from prior agreements or reserved equipment slots; or,

   vi. Negotiated outside of a competitive process specific to the Proposed Generators;

Question No.: STAFF 1-151 Part No.: Addendum:

c. Identify whether the costs identified in part (a):

iv. Are included within the EPC contract price;

v. Arc procured separately by ELL; or

vi. Are subject to escalation, true-up, or other adjustment mechanisms;

Response:

The Company objects to the "Instructions" included with the request to the extent they seek to impose any obligations or requirements on ELL that exceed the obligations or requirements provided for in the articles of the Louisiana Code of Civil Procedure. The Company further objects to the directive that "these requests are continuing so as to require supplemental responses" as such directive seeks to impose obligations beyond what is required under the Louisiana Code of Civil Procedure, Article 1428. Subject to and without waiving the objections, the Company responds as follows.

Information responsive to this request has been designated as Highly Sensitive Protected Material ("HSPM") and will be produced only to the appropriate Reviewing Representatives in accordance with the Confidentiality Agreement in effect and executed in this docket. HSPM files will be served upon appropriate reviewing representatives through an OpenText™ Core Share link. Any downloads of such files shall be treated in accordance with the applicable provisions of the Confidentiality Agreement regarding duplication of HSPM files.

[redacted]

a. Below is detailed breakdown cost associated with the Power Island Equipment (PIE) for Units 1-2 (Richland Parish 1-2) EPC Contract. Pricing of PIE for Units 3-4 [redacted] will align with this structure and current estimates are Entergy's escalation on what they could be by the time Mitsubishi provides final numbers in the Fall of 2026.

PIE Contract Components		
Combustion Turbines & Generators (2ea)	[redacted]	

Steam Turbines & Generators (2ea)	[redacted]
Transportation (CT/CTG/ST/STG and Auxiliaries)	
HRSGs including transportation (2)	
Construction Support and Fees	
Total	

b. PIE pricing is governed by an Exclusivity Agreement with Mitsubishi.

c. See the table in subpart (a) above.

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

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

Question:

Please provide the most recently conducted study on energy efficiency potential in the Company's service area, including any details regarding technical and economic potential.

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving the objections, the Company responds as follows.

While the full potential study has not been finalized or filed yet, the draft results of the most recent potential study conducted for the Company's ongoing IRP cycle was filed within LPSC Docket U-37764 on April 24, 2026, and is available at this address:

https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/ViewFile?fileId=a1ECTljfkBI%3d

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

Response of: Entergy Louisiana, LLC
to the First Set of Data Requests
of Requesting Party: Sierra Club

Question No.: SIERRA 1-3 Part No.: Addendum:

Question:

Regarding capacity expansion modeling:

a. Did the Company complete any capacity expansion modeling for this Application? If not, please identify the most recent capacity expansion modeling the Company completed.

b. Provide a summary of the scenarios, inputs, and outputs from the most recent capacity expansion modeling identified in part (a).

c. What modeling software did the Company use for the modeling described in part (a)?

Response:

ELL incorporates in full the General Objections served with these Requests. Subject to and without waiving the objections, the Company responds as follows.

a. No capacity expansion modeling was performed for this Application. Due to the energy and capacity needs of the Customer's electrical load, and the timeline by which electric service was desired by the Customer, the resource options available to the Company that would have been able to meet the Customer's needs while also ensuring the reliability and resource adequacy of the system were limited. The Company was able to utilize long-term resource planning best practices and experience is developing the portfolio of resources needed to serve the Customer. This resource plan was then evaluated with the production cost simulations and the resource adequacy analyses (the latter of which was particularly instrumental in the determination of the amount of non-firm load needed prior to the commercial operations date of the combined cycle power plants) described in Company witness Mr. Datta's Direct Testimony. The last capacity expansion modeling run for Entergy Louisiana, LLC is the 2023 IRP. All information related to the 2023 IRP is available at the website below, specifically pages 86 – 90.

Louisiana Integrated Resource plan 2023 - Entergy Louisiana

b. See the response to subpart (a)

c. See the response to subpart (a) for any modeling done for this filing. The 2023 IRP capacity expansion modeling was done using Aurora.

ENTERGY LOUISIANA, LLC
LOUISIANA PUBLIC SERVICE COMMISSION
Docket No. U-37882

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

Question No.: AAE 5-8 Part No.: Addendum:

Question:

Please refer to ELL's plan for serving the Customer's load during the bridge period (2026–2031) before all seven CCCTs are in service:

a. The projected cost and risk exposure to existing customers of procuring energy and capacity from the MISO spot market or ELL's existing fleet to serve the Customer's load during each year of the bridge period, expressed in dollars per year and in aggregate, and the assumptions underlying those projections.

b. ELL's estimate of the incremental variable supply cost borne by existing customers — through the Fuel Adjustment Clause or otherwise — as a result of serving the Customer's load during the bridge period "through spot market purchases and dispatch of ELL's existing fleet at higher utilization levels" before the CCCTs are available to provide "lower variable cost energy." (Owens Q11).

c. The basis on which ELL determined that the firm load tranche can be accommodated "without materially increasing the likelihood of having to curtail firm load." Please explain whether ELL conducted analysis to quantify this likelihood. In the case that ELL has to curtail firm load, please explain and provide documentation for any procedure that identifies which load would be curtailed (i.e. load from Meta or other customers).

d. Any scenario analysis ELL performed quantifying the cost to existing customers if one or more of the Richland Parish CCCTs fails to achieve its scheduled commercial operation date and the bridge period is extended.

e. The consequences, both contractual and operational, if one or more of the Proposed Generators fails to achieve its scheduled commercial operation date. At minimum, include the following:

i. increases cost and reliability exposure of existing ratepayers;

ii. any terms outlining Customer's contractual rights if the construction of the units is delayed or the associated budget significantly increases.

Response:

ELL incorporates in full the General Objections served with these Requests. The Company further objects to this request to the extent it seeks analyses the Company has not previously performed. The Company also objects to this request as its subparts do not pose a request. Subject to and without waiving the objections, the Company responds as follows.

a. Please see the Company's response to subpart b below for energy costs. The Company has not calculated the potential costs of procuring capacity from the "MISO spot market", assuming this term refers to the MISO Planning Resource Auction. However, row 52 ("Capacity Benefit/(Cost)") of the "Analysis" tab of HSPM-AEO Exhibit SD-2 Errata to Company witness Mr. Samrat Datta's Direct Testimony quantifies the annual difference in ELL's capacity position resulting from the addition of the Customer's load and resources during the bridge period (and beyond for the remainder of the Original Term of the ESA) at the levelized real cost of a CT. Please also see the Company's response to Staff 1-21.

b. As explained in Question 12, Question 13 and Question 25 of Company witness Mr. Datta's Direct Testimony, the production cost runs that were performed in support of the economic analysis presented in his Direct Testimony simulated the impact of the addition of the Customer's load and resources available during 2026-2031 timeframe (and beyond through the Original Term of the ESA) on the Company's variable supply cost. Please see "VSC" tab for the change in variable supply cost by year for ELL, and the associated change in the average cost-per MWh in the HSPM-AEO attachment provided in response to Staff 1-23.

c. Please see the Company's response to Staff 1-11.

d. No such scenario analysis has been performed. Please see the Section 4.B ("Modification of Ramp Schedule" of Rider 1 to the ESA provided as HSPM-AEO Exhibit LKB-2 for the provisions contained within the ESA that allow the Company to modify the Customer's load ramp in response to change to the in-service date of any Generation Asset.

e. Please see the response to subpart d above. In addition, please see Appendix A of the ESA provided as provided as HSPM-AEO Exhibit LKB-2 for the provisions pertaining to the true-up mechanism associated with adjustments to the Average Demand and Monthly Minimum Charges that may result from changes to actual construction costs of the Proposed Generators. No operational analysis has been performed pertaining to the scenario described in the question.

Docket No. U-37882

Exhibit EB-2

CURRENT
ENERGY GROUP

Edward Burgess

Partner, eburgess@currentenergy.group

Professional Summary

Ed has over 13 years of experience working as a consultant in the energy and utilities industry. He specializes in various grid planning issues including the integration of renewable energy, energy storage, electric vehicles, and distributed energy resources. He has provided expert testimony on over 30 occasions before 13 state utility commissions on issues including utility resource planning, transmission planning, fuel and power purchase costs, rate design, and electric vehicle programs.

Prior to co-founding Current Energy Group in 2024, Ed was a Consulting Partner at Strategen Consulting. While at Strategen, he directed the company's grid planning practice area, where he provided technical consulting services to a variety of public and private sector clients including state and federal government agencies, Fortune 500 companies, trade associations, and public interest organizations. Ed also helped launch and served as the inaugural Director for the Vehicle-Grid Integration Council growing the organization to over 40 member companies. Additionally, he worked for Arizona State University where he helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council.

Education

Professional Science Masters, Solar Energy Engineering and Commercialization
Arizona State University – Tempe, AZ (2012)

Master of Science, Sustainability
Arizona State University – Tempe, AZ (2011)

Bachelor of Arts, Chemistry
Princeton University – Princton, NJ (2007)

Work Experience

Founder, Current Energy Group (March 2024 – Present)

Consulting Partner, Strategen Consulting (August 2015 – March 2024)

- Joined in 2015 and helped grow the company's consulting practice team by more than 3 times.
- Directed the company's grid planning practice area, where he provided technical consulting services to a variety of public and private sector clients including state and federal government agencies, Fortune 500 companies, trade associations, and public interest organizations.
- Helped launch and served as the inaugural Director for the Vehicle-Grid Integration Council and grew the organization to over 40 member companies.

Independent Consultant (2012 – 2015)

- Worked as a technical consultant supporting various clients for attorney Kris Mayes (former Arizona Corporation Commission Chair and current Arizona Attorney General).
- Technical consultant for Schlegel & Associates, working with a coalition of Fortune 500 companies on energy efficiency and demand-side management policies across the US.

Research Associate, Arizona State University (2012-2015)

- Worked across disciplines as a researcher and program administrator for various efforts related to energy and sustainability.
- Assisted in launching the University's Utility of the Future initiative as well as the Energy Policy Innovation Council.
- Conducted a technical study in partnership with Arizona Department of Environmental Quality on the compliance pathways and impacts of the EPA's Clean Power Plan.

Research Fellow, Environmental Defense Fund (2007 – 2009)

Expert Testimony

California Public Utilities Commission

On behalf of Sierra Club:

- Pacific Power 2020 Energy Cost Adjustment Clause (Docket No. A.19-08-002)
- Pacific Power 2021 Energy Cost Adjustment Clause (Docket No. A.20-08-002)
- Pacific Power 2022 Energy Cost Adjustment Clause (Docket No. A.21-08-004)

On behalf of the Vehicle Grid Integration Council:

- Pacific Gas and Electric's Day-Ahead Real Time Rate and Pilot (Docket No. A.20-10-011)
- Pacific Gas and Electric's Electric Vehicle Charge 2 Application (Docket No. A.21-10-010)
- CPUC Rulemaking on Emergency Summer Reliability (Docket No. R.20-11-003)

Colorado Public Utilities Commission

On behalf of Advanced Energy United:

- Xcel Energy Colorado's 2025 Distribution System Plan and Aggregated Virtual Power Plant Program (Docket Nos. 24A-0547E & 25A-0061E)

CURRENT ENERGY GROUP

On behalf of Interest Energy Alliance:
- Tri-State Generation and Transmission 2023 Electric Resource Plan (Docket No. 23A-0585E)
- Tri-State Generation and Transmission Application for a CPCN (Docket No. 22A-0085E)

Indiana Utility Regulatory Commission

On behalf of the Citizens Action Coalition:
- Duke Energy Fuel Adjustment Clause (Cause No. 38707 FAC 125)
- Duke Energy Fuel Adjustment Clause –Sub-docket Investigation (Cause No. 38707 FAC 123 S1)

Louisiana Public Service Commission:

On behalf of the Alliance for Affordable Energy:
- Entergy Certification to Deploy Natural Gas Distributed Generation (Docket No. U-36105)

Massachusetts Department of Public Utilities

On behalf of the Attorney General's Office
- National Grid General Rate Case (D.P.U. 18-150)
- Eversource, National Grid, and Until SMART Tariff (D.P.U. 17-140)

Michigan Public Service Commission

On behalf of Earth Justice:
- Consumers Energy 2021 Integrated Resource Plan (Docket No. U-21090)

Nevada Public Utilities Commission

On behalf of Western Resource Advocates:
- NV Energy's Integrated Resource Plan (Docket No. 20-07023)
- NV Energy's Integrated Resource Plan (Docket No. 22-09006)

On behalf of Advanced Energy United:
- NV Energy's Integrated Resource Plan (Docket No. 24-05041)

North Carolina Utilities Commission

On behalf of the Attorney General's Office:
- Duke Energy Carolinas 2026 General Rate Case (Docket No. E-7, Sub 1329)
- Duke Energy's 2025 Carbon Plan and Integrated Resource Plan Proceeding (Docket Nos. E-100, Subs 207)

- Duke Energy's 2023 Carbon Plan and Integrated Resource Plan Proceeding (Docket No. E-100, Sub 190)
- Duke Energy's 2022 Carbon Plan (Docket No. E-100, Sub 179)
- Duke Energy Progress' 2023 General Rate Case (E-2, Sub 1300)
- Duke Energy Carolinas' 2023 General Rate Case (E-7, Sub 1276)
- Duke Energy Business Combination Proceeding (E-2, Sub 1393 and E-7, Sub 1332)

Oregon Public Utilities Commission

On behalf of Sierra Club:
- Pacific Power 2021 Transition Adjustment Mechanism (Docket No. UE-375)
- Pacific Power 2022 Transition Adjustment Mechanism (Docket No. UE-390)

On behalf of Earth Justice:
- Northwest Natural 2022 General Rate Case (Docket No. UG-435)

South Carolina Public Service Commission

On behalf of the South Carolina Solar Business Association:
- Dominion Energy South Carolina 2019 Avoided Cost Methodologies (Docket No. 2019-184-E)
- Duke Energy Carolinas 2019 Avoided Cost Methodologies (Docket No. 2019-185-E)
- Dominion Energy Progress 2019 Avoided Cost Methodologies (Docket No. 2019-186-E)
- Dominion Energy South Carolina 2021 Avoided Cost Methodologies (Docket No. 2021-88-E)

Utah

On behalf of Sierra Club
- PacifiCorp 2026 Inter-jurisdictional Cost Allocation Protocol (Docket No. 25-035-47)

Virginia

On behalf of Advanced Energy United:
- Dominion Energy 2023 Integrated Resource Plan (Case No. PUR-2023-00066)

Washington Utilities and Transportation Commission

On behalf of Sierra Club:
- Avista Utilities 2020 General Rate Case (Docket No. UE-200900)
- Avista Utilities 2022 General Rate Case (Docket No. UE-220053/UG-220054)
- Puget Sound Energy 2022 General Rate Case (Docket No. UE-220066/UG-220067)

Wisconsin Public Service Commission

On behalf of the Wisconsin Citizen's Utility Board:

- Wisconsin Electric Certificate of Public Convenience and Necessity (Docket No. 6630-CE-316)
- Wisconsin Electric Certificate of Public Convenience and Necessity (Docket No. 6630-CE-317)
- Wisconsin Electric Certificate of Authority (Docket No. 6630-CG-140)

Selection of Relevant Experience

Western Resource Advocates

Nevada Energy IRP Analysis / 2018 -2019

- Conducted a thorough technical analysis and report on the NV Energy IRP (Docket No. 18-06003).
- Investigated resource mixes that included higher levels of demand side management, renewable energy, battery storage, and decreased reliance on existing and/or planned fossil fuel plants.

Massachusetts Office of the Attorney General

SMART Program / 2016 -2017

- Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years.
- Served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

Southwest Energy Efficiency Project

IRP Technical Analysis and Modeling / 2018 -2020

- Provided critical analysis and alternatives to the 2020 integrated resource plans (IRPs) of the state's major utilities, Arizona Public Service (APS) and Tucson Electric Power (TEP).
- Provided analysis on Salt River Project's resource plan as part of its 2035 planning process.
- Evaluated different levels of renewable energy and energy efficiency and identify any changes to the resources needed to meet these requirements and ensure reliability.
- Worked with Strategen technical team on utilizing a capacity expansion model to optimize the clean energy portfolio used in the analysis of the IRPs.

California Energy Storage Alliance

California Hybridization Assessment / 2018 -2019

- Managed a special initiative of this leading industry trade group to conduct technical analysis and stakeholder outreach on the value of hybridizing existing gas peaker plants with energy storage,

Portland General Electric

Energy Storage Strategy / 2016

- Provided education and strategic guidance to a major investor-owned utility on the potential role of energy storage in their planning process in response to state legislation (HB 2193).

- Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.
- Supported development of a competitive solicitation process for storage technology solution providers.

Arizona Residential Utility Consumer Office (RUCO)
IRP Analysis and Impact Assessment / 2015 -2018
- Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
- Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
- Lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Sierra Club
PacifiCorp 2021 IRP Technical Support / 2020 -2021
- Provided technical support for Sierra Club in analyzing issues of interest during Pacificorp's IRP stakeholder input process.
- Prepared analysis, technical comments, discovery requests in advance of drafting formal comments to be submitted before the Oregon Public Utility Commission.

North Carolina, Office of the Attorney General
Duke Energy 2020 IRP Technical Support / 2020 -2021
- Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.
- Presented original analysis at multiple IRP-related technical workshops hosted by the NCUC

University of Minnesota
Energy Storage Stakeholder Workshops / 2016 -2017
- Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.
- Conducted study on the use of storage as an alternative to natural gas peaker.
- Presented workshop and study findings before the Minnesota Public Utilities Commission.

New Hampshire Office of Consumer Advocate
NEM Successor Tariff Design / 2016
- Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources, developing a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

Xcel Energy
Time-of-use Rates / 2017 -2018

- Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

Publications

- New York BEST, 2020. Long Island Fossil Peaker Replacement Study.
- Ceres, 2020. Arizona Renewable Energy Standard and Tariff: 2020 Progress Report.
- Virginia Department of Mines and Minerals, 2020. Commonwealth of Virginia Energy Storage Study.
- Sierra Club, 2019. Arizona Coal Plant Valuation Study.
- Strategen, 2018. Evolving the RPS: Implementing a Clean Peak Standard."
- SunSpecAlliance for California Energy Commission.,2018.Analysis Report of Wholesale Energy Market Participation by Distributed Energy Resources (DERs) in California.