



Louisiana Public Service Commission

POST OFFICE BOX 91154
BATON ROUGE, LOUISIANA 70821-9154
lpsc.louisiana.gov

CC: MV

COMMISSIONERS

Eric Skrmetta, Chairman
District I
Jean-Paul P. Coussan, Vice Chairman
District II
Foster L. Campbell
District V
Mike Francis
District IV
Davante Lewis
District III

Telephone: (225) 342-9888

July 31, 2026

BRANDON M. FREY
Executive Secretary

KATHRYN H. BOWMAN
Executive Counsel

JOHNNY E. SNELLGROVE, JR.
Deputy Undersecretary

VIA HAND DELIVERY

Louisiana Public Service Commission
Records and Recordings
602 N. Fifth Street
Galvez Building, 12th Fl.
Baton Rouge, LA 70802

LA PUBLIC SERVICE COMM
JUL 31 2026 PM02:22

Re: Docket U-37882, Entergy Louisiana, LLC, ex parte. In re: Application for certification of generation and transmission resources and for other relief.

To whom it may concern:

The Direct Testimony of R. Lane Sisung is enclosed for filing in the above-captioned matter. HSPM and AEO versions of this filing are being provided under seal. Please file the enclosed into the record of the above-captioned docket and provide a copy to the Administrative Hearings Division. If you have any questions regarding this filing, please do not hesitate to contact me.

Respectfully submitted,

Lauren T. Evans (Bar Roll No. 35576)
Deputy General Counsel
Louisiana Public Service Commission
602 North Fifth Street, Galvez Bldg., 12th Fl.
Baton Rouge, Louisiana 70802
Ph. (225) 342-9888
Email: lauren.evans@la.gov

cc: Service List (via email)

PUBLIC VERSION
AEO/HSPM INFORMATION HAS BEEN REMOVED

**BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION**

DOCKET NUMBER U-37882

LA PUBLIC SERVICE COMM
JUL 31 2026 PM02:22

ENTERGY LOUISIANA, LLC, EX PARTE.

***IN RE: APPLICATION FOR CERTIFICATION OF GENERATION AND
TRANSMISSION RESOURCES AND FOR OTHER RELIEF.***

**DIRECT TESTIMONY
OF
R. LANE SISUNG
ON BEHALF OF THE
STAFF OF THE
LOUISIANA PUBLIC SERVICE COMMISSION**

PUBLIC VERSION

JULY 31, 2026

TABLE OF CONTENTS

I.	INTRODUCTION	1
A.	The Application	3
B.	Applicable LPSC Orders.....	15
II.	ELL’S SUPPLY AND TRANSMISSION PLAN UNDERLYING ITS REQUESTS FOR CERTIFICATION.....	20
III.	MBM ORDER/ LIGHTNING INITIATIVE	31
IV.	ELL’S GENERATION AND TRANSMISSION CERTIFICATION REQUESTS	36
A.	Standard of review	36
B.	Review of the Proposed Capacity Supply and Transmission Plans	40
C.	Large Load Guidelines.....	41
1.	LARGE LOAD GUIDELINE #1: Need, Scope, and Load Characteristics.....	44
2.	LARGE LOAD GUIDELINE #2: Resource Adequacy & Capacity	47
3.	LARGE LOAD GUIDELINE #3: Transmission and Interconnection	50
4.	LARGE LOAD GUIDELINE #8: Fuel Supply and Infrastructure Risk	53
5.	LARGE LOAD GUIDELINE #11: Environmental & Local Impacts.....	56
6.	LARGE LOAD GUIDELINE #9: Load Ramp Management.....	59
7.	LARGE LOAD GUIDELINE #6: Operational Control and Curtailement	66
8.	LARGE LOAD GUIDELINE #7: Ancillary Services and Power Quality.....	69
9.	LARGE LOAD GUIDELINE #10: Market and Planning Impacts	75
10.	LARGE LOAD GUIDELINE #5: Rate Design and Cost Recovery	81
11.	LARGE LOAD GUIDELINE #4: Stranded Asset and Exit Risk.....	105
12.	LARGE LOAD GUIDELINE #12: Ongoing Oversight.....	136
D.	Review of ELL’s Proposed TCI	137
E.	Conclusions and Recommendations Regarding the Requested Certifications	153

V.	ACCOUNTING, RATEMAKING, SUSTAINABILITY AGREEMENT AND OTHER RELATED ISSUES	157
	A. Accounting and Ratemaking Prayers for Relief	157
	B. Sustainability Agreement Prayers for Relief	170
VI.	CONCLUSION	175

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, PLACE OF EMPLOYMENT, TITLE, AND BUSINESS ADDRESS.

A. My name is R. Lane Sisung. I am President of United Professionals Company, LLC (“UPC”). My business address is 3850 North Causeway Boulevard, Suite 1930, Metairie, Louisiana 70002.

Q2. PLEASE DISCUSS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science degree in Accounting from Louisiana State University in Baton Rouge, Louisiana, and I sat for and passed the Certified Public Accounting Examination. I attended Loyola School of Law, where I was a member of the Law Review and received my Juris Doctor degree. I then furthered my legal and accounting education at the University of Florida where I received an L.L.M. in Tax Law. I am a fully licensed General Securities Representative (Series 7), General Securities Principal (Series 24), Options Principal (Series 4), Financial and Operations Principal (Series 27), and Registered Investment Adviser (Series 65). I am a member of the Society of Utility Regulatory Financial Analysts, by which I have been qualified as a Certified Rate of Return Analyst (“CRRA”).

Q3. PLEASE BRIEFLY DESCRIBE YOUR PRIOR REGULATORY EXPERIENCE.

A. I have more than thirty years of experience in financial, investment, and regulatory matters. I began my career in the highly regulated areas of investment banking and investment management and later expanded my experience to include venture capital and project development/management. I have spent the past fifteen years primarily focused on utility

1 regulation. I currently serve as the principal of UPC, where I manage and provide
2 regulatory consulting services to public utility commissions. In that role, I regularly advise
3 on complex regulatory and financial issues and have provided consulting and expert
4 testimony in numerous proceedings, including rate determinations, generation and
5 transmission certifications, mergers and acquisitions, prudence reviews, forensic
6 investigations, and general rulemakings. I am also currently advising the Louisiana Public
7 Service Commission on matters related to the participation of its investor-owned utilities
8 in the Midcontinent Independent System Operator (“MISO”) and Southwest Power Pool
9 (“SPP”) regional transmission organizations, including issues involving transmission
10 planning, market design, and cost allocation. An illustrative list of the utility regulatory
11 dockets in which I have provided services is attached as Exhibit RLS-001.

12 **Q4. ON WHOSE BEHALF ARE YOU APPEARING IN THIS DOCKET?**

13 A. I am appearing on behalf of the Commission Staff (“Staff”).

14 **Q5. WHY ARE YOU SUBMITTING THIS DIRECT TESTIMONY?**

15 A. UPC was retained by the Louisiana Public Service Commission (“Commission”) to review
16 and evaluate Entergy Louisiana, LLC’s (“ELL” or “Company”) Application seeking,
17 among other things, certification of proposed generation and transmission facilities as
18 serving the public convenience and necessity and being in the public interest to support
19 electric service to Evest, LLC (“Evest”), a proposed new customer associated with and
20 guaranteed by Meta Platforms, Inc. (“Meta”) with a projected maximum demand of
21 approximately [REDACTED] MW.

22 The magnitude of the requested load is extraordinary. Evest’s projected maximum
23 demand is equivalent to approximately [REDACTED] percent of ELL’s current system peak load.

1 When combined with the approximately [REDACTED] MW maximum demand associated with
2 Laidley, LLC ("Laidley"), another Meta related and guaranteed large customer seeking
3 service from ELL during a similar timeframe, the combined requested load approaches [REDACTED]
4 percent of ELL's current system peak demand. Accordingly, the Company's request for
5 certification of the facilities proposed to serve this load presents significant engineering,
6 operational, economic, financial, and regulatory issues that require careful evaluation under
7 the Commission's established certification standards.

8 **Q6. WHAT DID YOU RELY ON IN PREPARING YOUR TESTIMONY?**

9 A. I reviewed and relied on ELL's filed Application and supporting exhibits, including the
10 direct testimony and exhibits of the Company's 15 witnesses. I also reviewed and analyzed
11 the information provided by ELL in response to numerous data requests propounded by
12 Staff and intervenors.¹

13 **A. THE APPLICATION**

14 **Q7. PLEASE DESCRIBE THE COMPANY'S APPLICATION.**

15 A. The Application includes multiple "Prayers for Relief" associated with ELL's proposal to
16 provide electric service to Evest's projected maximum demand of approximately [REDACTED]
17 MW. To allow ELL to be able to support that proposed service, ELL seeks certification of
18 new generation and transmission facilities, together with several related accounting,
19 ratemaking, and regulatory determinations. The Application presents testimony and

¹ Intervenors in this proceeding include the Louisiana Energy Users Group ("LEUG"), Southern Renewable Energy Association ("SREA"), Alliance for Affordable Energy ("AAE"), 1803 Electric Cooperative ("1803"), Sierra Club ("Sierra"), Association of Louisiana Electric Cooperatives ("ALEC"), Gulf States Renewable Energy Industry Association ("GSREA"), and the Union of Concerned Scientists ("UCS") (AAE and UCS are collectively referred to as the Non-Profit Organizations or "NPOs"). Of the intervenors, LEUG, SREA, Sierra Club, and the NPOs served discovery requests on ELL.

1 supporting evidence addressing the projected need for the proposed facilities, the
2 Company's proposed resource plan, the anticipated costs and benefits of the proposal, and
3 various customer agreements and other supporting documentation relied on by the
4 Company in support of its requested relief.

5 **Q8. SPECIFICALLY, WHAT IS ELL REQUESTING IN THE APPLICATION?**

6 A. ELL's Application contains a number of requests. For purposes of this testimony, I have
7 grouped the nineteen substantive requests into seven categories discussed below. Prayers
8 for Relief Nos. 20 through 26 are procedural or general "catchall" requests. I make no
9 recommendation with respect to the procedural requests. In addition, I do not recommend
10 that the Commission make the general finding requested in Prayer for Relief #20 that the
11 Company has complied with all Commission orders. Rather, I recommend that the
12 Commission make findings regarding compliance only where the Company has requested
13 a determination with respect to a specific Commission Order and has presented evidence
14 sufficient to support such a finding. My summary of ELL's remaining substantive Prayers
15 for Relief is as follows:²

16 **GENERATOR CERTIFICATION REQUESTS - A finding that the**
17 **construction of the Proposed Generators and Battery Storage Facilities is in the**
18 **public interest and recoverable in ELL's rates:**
19

- 20 ○ **Prayer for Relief 1** - Find that the Company's construction of four
21 new CCCT generators near the Customer Project in Richland Parish,
22 Louisiana, and three new CCCT generators at Pointe Coupee serves the
23 public convenience and necessity and is in the public interest, and is
24 therefore prudent, in accordance with the Commission's 1983 General
25 Order.
26
- 27 ○ **Prayer for Relief 2** - To the extent required by law, find that the
28 construction of and/or acquisition of capacity from the three Battery
29 Storage Facilities in SELPA serves the public convenience and

² Defined Terms in the Prayers for Relief are as defined in the Application.

necessity and is in the public interest, and is therefore prudent, in accordance with the Commission's 1983 General Order. (

- **Prayer for Relief 3** - Based on the facts and analyses presented herein demonstrating the benefits of the Proposed Generators and Battery Storage Facilities to all ELL customers, approve of the inclusion and treatment of the Proposed Generators and Battery Storage Facilities as system resources for the benefit of all ELL customers, and not as resources constructed and designated for the benefit and use of a specific Customer, and, accordingly find 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.

MBM WAIVER REQUEST - *A finding that ELL has satisfied the requirements of the Commission's Lightning Initiative such that the requirements in the MBM Order are waived:*

- **Prayer for Relief 5** - Find that the Company has satisfied the requirements of the Commission's Lightning Initiative such that the requirements of the MBM Order are waived or, alternatively, under the specific facts and circumstances of this case, including significant Customer funding, the need for expedited action to secure the Customer's investment in Louisiana, the substantial economic benefits to the citizens of the State of Louisiana afforded by the Project, and other circumstances described in the Company's Application and supporting Direct Testimony, good cause exists for the granting of, and for the Commission to grant, an exemption to the formal RFP process included in the MBM Order, to the extent it is found applicable, including the stated prohibition in the MBM Order against alternative market-based mechanisms being "limited to self-build or utility-owned resources," as well as any other requirements of the MBM Order that may not be met based on the facts presented herein.

TRANSMISSION CERTIFICATION REQUESTS - *A finding that, to the extent necessary, the Commission certify the construction of the proposed Transmission projects and authorize recovery as proposed by ELL:*

- **Prayer for Relief 6** - With respect to transmission, the Commission should find:
 - As to the Customer-Funded Transmission Interconnection Project, that certain components of these transmission facilities (specifically, the WFC substation and the nine new auxiliary 230kV switching stations) do not require certification pursuant to the Transmission Siting Order as they do not fall within the definition of

1 “Transmission Facilities” and, further, that the exemption set forth
2 in Section VIII(a) therein applies.

- 3
4 - As to the other components of the Customer-Funded Transmission
5 Interconnection Project (specifically, the 20-30 miles of 230kV
6 transmission lines to connect the Customer’s load to the ELL
7 Transmission System) and as to the Smalling to El Dorado 500kV
8 Line, the Commission should find that such projects are exempt
9 from the requirements of the Transmission Siting Order pursuant to
10 the first sentence of Section VIII and the exemption in Section
11 VIII(h) of the Transmission Siting Order, because (1) “the costs of
12 the [referenced facilities], and the cost of any associated System
13 Impacts, will never be reflected or recovered in the retail or
14 wholesale rates to be assessed to customers of Louisiana electric
15 utilities including cooperatives,” or (2) in the further alternative,
16 “good cause” exists to exempt the interconnection from
17 certification, because there is no risk that the costs of these
18 components of the Customer-Funded Transmission Interconnection
19 Project and of the Smalling to El Dorado 500kV Line will fall on
20 retail customers;

- 21
22 - As to the Proposed Transmission Facilities—and as to the
23 Customer- Funded Transmission Interconnection Project and
24 Smalling to El Dorado 500kV Line if none of the above-referenced
25 exemptions are found to apply—that (1) such facilities are in the
26 public interest and the interests of affected customers, taking into
27 account the costs, retail rates, service reliability, reduction of
28 congestion, material economic benefits, the interstate or intrastate
29 benefits expected to be achieved, and the fact that such facilities are
30 consistent with public policy, including policy goals of the
31 Commission; and that (2) the generalized siting of the facilities is
32 appropriate and construction of the facilities (as opposed to
33 construction of other transmission facilities or construction of
34 generation, or non- transmission alternative) is a reasonable and
35 cost-effective solution to the problems being addressed by such
36 facilities;

37
38 **RATEMAKING REQUESTS - *Approval of ELL’s proposed ratemaking***
39 ***treatment for the revenue received from the Customer and the revenue***
40 ***requirement of the Planned Generators and Transmission facilities:***

- 41
42 ○ **Prayer for Relief 10** - Approve the Company’s establishment of a
43 regulatory liability for accounting purposes, as described in the
44 Application and supporting Direct Testimony, to, inter alia, stabilize
45 the effects of the proposed investments and Customer revenue on the

1 rates charged in accordance with the FRP and resulting customer bill
2 impacts;
3

- 4 ○ **Prayer for Relief 11** - Approve of the requested accounting treatment
5 of the Customer's other contributions made pursuant to the ESA and/or
6 CIAC Agreement, as well as the receipt of any termination fee as a
7 result of early termination, as described in the Application and
8 supporting Direct Testimony.
9
- 10 ○ **Prayer for Relief 12** - Find that the retail revenue requirements
11 associated with the actual prudently incurred costs of the Proposed
12 Transmission Facilities, estimates of which are provided by Mr. Jones
13 in his Direct Testimony, net of offsetting Customer revenues, are
14 deemed eligible for recovery by the Company through the applicable
15 mechanisms of the FRP to the extent the Company remains subject to
16 an FRP at the time the referenced facilities are placed in service, or in
17 the alternative, through the creation and authorization of a regulatory
18 asset, with interest to be accrued thereon at the Company's weighted
19 average cost of capital, until such time that the costs can be reflected
20 in rates through a future base rate proceeding.
21
- 22 ○ **Prayer for Relief 13** - Find that the retail revenue requirements
23 associated with the Proposed Generators and the Battery Storage
24 Facilities (to be determined in subsequent revenue requirement filings)
25 are deemed eligible for recovery in the first billing cycle of the month
26 following commercial operation of each of the Proposed Generators
27 and Battery Storage Facilities in accordance with the terms of the
28 Company's then-effective FRP, including more specifically the
29 Additional Capacity Mechanism of the FRP if applicable, and outside
30 of the FRP sharing mechanism and outside of any applicable caps, and
31 subject to offset by deferred Customer revenue as described in the
32 Company's Application and Direct Testimony; in the alternative, if
33 ELL does not have an FRP in place at the time the Proposed Generators
34 and/or Battery Storage Facilities are placed in service, authorize (i) a
35 deferral of the non-fuel revenue requirement (i.e., costs that are not
36 eligible to be recovered through the FAC) associated with each of the
37 Proposed Generators and Battery Storage Facilities until such time as
38 the costs of each of the Proposed Generators and Battery Storage
39 Facilities are separately reflected in the Company's retail rates; (ii) a
40 deferral of the costs to hire and train each Proposed Generator's plant
41 staff in advance of each of the respective Proposed Generator's in-
42 service date; and (iii) an accrual of carrying charges on the deferred
43 balances at the Company's weighted average cost of capital,
44 commencing on the dates of commercial operation for each of the
45 Proposed Generators and Battery Storage Facilities and continuing
46 until such time as such costs for each of the Proposed Generators and

Battery Storage Facilities are first reflected in the Company's retail rates, subject to offset by deferred Customer revenue as described in the Company's Application and Direct Testimony.

- **Prayer for Relief 14** - Authorize the recovery, over a two-year period, of any remaining deferred balances referenced in the immediately preceding paragraph, beginning, as to each of the Proposed Generators and/or Battery Storage Facilities, contemporaneously with the time that the costs of such Proposed Generator and/or Battery Storage Facility begins to be recovered from customers through rates.
- **Prayer for Relief 15** - Authorize, with respect to the four Proposed Generators to be located in Richland Parish, a depreciable life of twenty (20) years and with respect to the three Proposed Generators to be located in Pointe Coupee, a depreciable life of thirty-two (32) years;
- **Prayer for Relief 16** - As to the amounts spent for purposes of securing interconnection rights for the Proposed Generators, through the various means described in the Direct Testimony of ELL witnesses Daniel Kline and Laura Beauchamp, allow the Company to accrue a return at the Company's weighted average cost of capital, on a net-of-tax basis, including as described in the Direct Testimony of Ryan M. Dumas, from the date incurred until such time as the costs for the associated generator commence to be recovered in retail rates, and further to deem these costs eligible for recovery in the same manner as the other costs to construct the Proposed Generators;
- **Prayer for Relief 17** - Approve recovery, through the FAC, of the variable expenses incurred under the Long-Term Service Agreements applicable to the Planned Generators.
- **Prayer for Relief 18** - Approve the inclusion, as a credit in the FAC, the revenues received from the Customer for the Company's purchases of energy during the Commissioning Period as described in testimony, based on the costs invoiced to the Customer for the applicable cost month;

SUSTAINABILITY AGREEMENT REQUESTS - *Approval of a process for procuring renewable generation and allocating costs outside of traditional Commission rules and procedure:*

- **Prayer for Relief 7** - As to the Sustainability Agreement described in the Application and presented as AEO/HSPM Exhibit ECI-2 to the Direct Testimony of Ms. Ingram and an attachment to the ESA included as AEO/HSPM Exhibit LKB-2 to the Direct Testimony of Ms. Beauchamp, confirm (a) the Customer is a "New Customer" (as

1 defined in Attachment 2 to the “Motion for consideration of
2 Uncontested Stipulated Settlement Term Sheet Pursuant to Rules 6, 51,
3 and 57” filed by ELL in Docket No. U-36697 on May 15, 2024), (b)
4 the Customer qualifies for a Geaux Zero Group 3 subscription for
5 purposes of securing approval, in the future, of the 2,500 MW of
6 Designated Renewable Resources contemplated by the Sustainability
7 Agreement and to designate those resources under the Sustainability
8 Agreement pursuant to its terms, and (c) the Company can employ the
9 expedited procurement and certification procedures set forth in the
10 3GW Order, as may be amended, to procure and seek certification of
11 Designated Renewable Resources to the extent allowed by the terms of
12 the 3GW Order, as may be amended.
13

- 14 ○ **Prayer for Relief 8** - Also, as to the Sustainability Agreement, approve
15 the proposed protections and dispute resolution process described by
16 Ms. Ingram in her Direct Testimony with respect to Designated
17 Renewable Resources that exceed the Breakeven Parameters set forth
18 in the 3GW Order, as may be amended;
19
- 20 ○ **Prayer for Relief 9** - Acknowledge that ELL may transfer to, and/or
21 otherwise utilize or retire on behalf of, the Customer any AECs
22 associated with the Waterford 3 uprate, if approved, the Waterford 3
23 refueling cycle upgrades described in the Sustainability Agreement, and
24 any other uprate to a nuclear facility owned by the Company to the
25 extent paid for by the Customer (including to the extent Customer pays
26 for a potential uprate at RBS and such uprate is approved by the
27 Commission in the future).
28

29 **MONITORING PLAN APPROVAL - *Approval of a monitoring plan to track***
30 ***the Customer’s and ELL’s construction activity and financial transactions;***
31

- 32 ○ **Prayer for Relief 19** - Approve the Monitoring Plan in the form
33 presented with the Company’s Application as Exhibit TH-2 to the
34 Direct Testimony of Mr. Heytens under which the Company will report
35 to Commission Staff on a quarterly basis the status of the Proposed
36 Generators, the Battery Storage Facilities and Planned Transmission
37 Facilities, including schedule, costs, and other critical associated
38 activities.
39

40 ***Confirmation of compliance with other Commission Orders:***
41

- 42 ○ **Prayer for Relief 4** - Find that the Application complies with the
43 requirements of General Order in Docket R-34860, and that the
44 requirements for entering into the ESA have been satisfied, because
45 ELL has submitted a filing pursuant to the 1983 General Order

requiring Commission certifications for the acquisition of power supply.

Q9. HAS STAFF ADDRESSED EACH OF ELL'S SUBSTANTIVE REQUESTS PRESENTED ABOVE?

A. Yes. The Table below provides a summary of ELL's requested relief, and where it is addressed in Staff's Testimony:

ELL Prayer for Relief Number as Referenced in Question 8 Above	Location in Staff's Testimony
Prayer for Relief 1 Generator Certification	Direct Testimony of R. Lane Sisung Section IV. ELL's Generation and Transmission Certification Request
Prayer for Relief 2 Batteries Certification	Direct Testimony of R. Lane Sisung Section IV. ELL's Generation and Transmission Certification Request
Prayer for Relief 3 Generator and Batteries System Resources for FAC Recovery	Direct Testimony of R. Lane Sisung Section V.A. Accounting and Ratemaking Prayers for Relief
Prayer for Relief 4 R-34860 Greater than 5% Requirement	Direct Testimony of R. Lane Sisung Section I.B. Applicable LPSC Orders
Prayer for Relief 5 Lightning Initiative	Direct Testimony of R. Lane Sisung Section III MBM/Lightning Initiative
Prayer for Relief 6 Transmission Certification	Direct Testimony of John A. Chapman <i>And</i> Direct Testimony of R. Lane Sisung Section IV. ELL's Generation and Transmission Certification Request
Prayer for Relief 7 New Customer/Geaux Zero	Direct Testimony of R. Lane Sisung V.B. Sustainability Agreement Requests
Prayer for Relief 8 Designated Renewable Resources Above Breakeven Parameter	Direct Testimony of R. Lane Sisung V.B. Sustainability Agreement Requests
Prayer for Relief 9 Nuclear AEC Utilization	Direct Testimony of R. Lane Sisung V.B. Sustainability Agreement Requests
Prayer for Relief 10 Deferred Revenue Regulatory Liability	Direct Testimony of R. Lane Sisung Section V.A. Accounting and Ratemaking Prayers for Relief
Prayer for Relief 11 CIAC Accounting	Direct Testimony of R. Lane Sisung Section V.A. Accounting and Ratemaking Prayers for Relief

Prayer for Relief 12 Transmission Ratemaking	Direct Testimony of R. Lane Sisung Section V.A. Accounting and Ratemaking Prayers for Relief
Prayer for Relief 13 Generator and Battery Ratemaking	Direct Testimony of R. Lane Sisung Section V.A. Accounting and Ratemaking Prayers for Relief
Prayer for Relief 14 Generator and Battery Ratemaking	Direct Testimony of R. Lane Sisung Section V.A. Accounting and Ratemaking Prayers for Relief
Prayer for Relief 15 Generator Depreciation	Direct Testimony of R. Lane Sisung Section V.A. Accounting and Ratemaking Prayers for Relief
Prayer for Relief 16 Generator Interconnection Ratemaking	Direct Testimony of R. Lane Sisung Section V.A. Accounting and Ratemaking Prayers for Relief
Prayer for Relief 17 LTSA Recovery	Direct Testimony of R. Lane Sisung Section V.A. Accounting and Ratemaking Prayers for Relief
Prayer for Relief 18 Commissioning FAC Revenue	Direct Testimony of R. Lane Sisung Section V.A. Accounting and Ratemaking Prayers for Relief
Prayer for Relief 19 Monitoring Pan	Direct Testimony of John A. Chapman
Prayers for Relief 20 through 26 are addressed in Question 8 above.	

Q10. CONSIDERING THAT ELL HAS SUBMITTED THE EVEST ESA AND RELATED DOCUMENTS IN SUPPORT OF THIS APPLICATION, PLEASE BRIEFLY DESCRIBE THE EVEST ESA AND RELATED DOCUMENTS.

A. For ease of reference throughout my testimony, I generally adopt the terminology used by Company witness Thomas Kidd.³ Collectively, I refer to the Electric Service Agreement (“ESA”), including the applicable Terms and Conditions of Service, Large Load Rate Schedule, and Rider 1, together with the Contribution in Aid of Construction and Capital Costs Agreement (“CIAC Agreement” or “CIAC”), as the Customer Agreements. These

³ Direct Testimony of Thomas Kidd at 3.

1 agreements establish the principal commercial framework governing the provision of
2 electric service, the construction of the facilities necessary to serve the Customer, the
3 allocation and recovery of costs from customer by ELL, and the respective rights and
4 obligations of the parties.

5 The information provided by ELL also includes several related agreements and supporting
6 documents. Among these is the Sustainability Agreement, which is incorporated into Rider
7 1 as Appendix G. While it forms part of the overall contractual framework, the
8 Sustainability Agreement expressly provides [REDACTED]

9 [REDACTED]
10 [REDACTED]. Accordingly, although related to the overall customer
11 arrangement, it should be considered distinct from the Customer Agreements. The
12 information provided by ELL also includes several Long Lead Agreements executed prior
13 to the Customer Agreements to facilitate the early procurement at the Customer's expense
14 of critical equipment and engineering services. Those agreements were subsequently
15 integrated into the overall project framework through the CIAC Agreement, which
16 recognizes and credits the payments previously made under those agreements.

17 **Q11. THE APPLICATION AND SUPPORTING TESTIMONY USE A NUMBER OF**
18 **DEFINED TERMS TO DESCRIBE THE PROPOSED GENERATION, STORAGE,**
19 **AND TRANSMISSION FACILITIES. FOR PURPOSES OF YOUR TESTIMONY,**
20 **PLEASE DESCRIBE THOSE TERMS.**

21 A. **Capacity Resources**

22 The "**Proposed Generators**" refer to seven new 754 MW 1x1 combined-
23 cycle combustion turbine ("CCCT") generating units, each consisting of

1 one Mitsubishi Power Americas (“MPA”) 501JAC combustion turbine, one
2 Nooter Eriksen heat recovery steam generator (“HRSG”) with duct firing
3 and selective catalytic reduction (“SCR”), and one MPA steam turbine
4 generator in a 1x1 combined-cycle configuration, together with the
5 associated balance-of-plant equipment, including air-cooled condensers for
6 closed-cycle cooling operations. Four of these generating units are proposed
7 to be located near the Customer’s site in Richland Parish, Louisiana, and
8 three are proposed to be located near the existing Big Cajun site in Pointe
9 Coupee Parish, Louisiana.⁴

10 The “**Battery Storage Facilities**” refer collectively to approximately [REDACTED]
11 MW of battery storage consisting of (i) a 200 MW battery at the proposed
12 Bogalusa West Solar Facility in Iberville Parish (“Bogalusa West Battery”),
13 a 200 MW battery at the proposed Cypress Harvest Solar Facility in
14 Washington Parish (“Cypress Harvest Battery”), and a [REDACTED]
15 [REDACTED] (the “Third
16 Battery”).⁵

17 ELL is also proposing, as part of its supply plan, that Evest fund two
18 resources that were already planned for the ELL system: the Bayou Cove
19 purchased capacity agreement (“PCA”)⁶ and the Waterford 3 nuclear

⁴ Direct Testimony of Norman Grunden at 4.

⁵ Direct Testimony of Laura Beauchamp at 4.

⁶ LPSC Docket No. U-37872 (*In re: Request for approvals relating to various purchase agreements and for associated cost recovery*).

1 uprate.⁷ Together with the Battery Storage Facilities, these resources are
2 referred to by the Company as the “**Other Supply Plan Resources**”.⁸

3 **Generation Assets** refers to the combination of The Proposed Generators,
4 the Battery Storage Facilities and the Waterford 3 Nuclear Uprate.

5 **Customer Funded Transmission Projects**

6 The “**Customer-Funded Transmission Interconnection Project**” refers
7 to the CIAC-funded facilities necessary to directly interconnect the
8 Customer to ELL’s transmission system, including the new West Fork
9 Creek (“WFC”) 500/230 kV substation, approximately 20 to 30 miles of
10 new 230 kV transmission lines, and nine new 230 kV auxiliary switching
11 stations. These facilities will generally be constructed on or immediately
12 adjacent to the Customer’s property utilizing land and servitudes provided
13 by the Customer and will be funded directly pursuant to the Customer’s
14 CIAC Agreement.⁹

15 The “**Customer-Funded Smalling to El Dorado 500kV Transmission**
16 **Line**” refers to a new approximately 90-mile 500kV transmission line
17 between North Louisiana and South Arkansas. Customer has a CIAC with

⁷ LPSC Docket No. U-37677 (*In re: Application for approval to complete uprate project at the Waterford 3 Nuclear Station, including cost recovery*).

⁸ *Id.* at 4 n.3.

⁹ Direct Testimony of Daniel Kline at 13.

1 each of ELL and Entergy Arkansas, LLC (“EAL”) to cover the full cost of
2 the line.¹⁰

3 Collectively the Customer-Funded Transmission Interconnection Project
4 and the Customer-Funded Smalling to El Dorado 500kV Transmission Line
5 are referred to as “**Customer Funded Transmission Projects**”.¹¹

6 **ELL-Funded Transmission Project**

7 The “**WFC–St. Landry 500 kV Transmission Line and Switching**
8 **Station**” refers to the proposed approximately 150-mile 500 kV transmission
9 project between West Fork Creek and St. Landry intended to strengthen the
10 500 kV transmission network between North and South Louisiana. This
11 project is proposed to be financed by ELL through traditional utility
12 financing. However, under the Company’s proposal, the Customer’s
13 Minimum Monthly Charge under the ESA is designed to recover the costs
14 associated with this investment during the term of the ESA. I discuss Staff’s
15 evaluation of that proposal later in this testimony.¹² These projects are also
16 collectively referred to as the “**ELL Funded Transmission Project**”.¹³

17 **B. APPLICABLE LPSC ORDERS**

¹⁰ *Id.* at 10, 14.

¹¹ Direct Testimony of Ryan Jones at 3.

¹² Direct Testimony of Daniel Kline at 18-19.

¹³ Direct Testimony of Ryan Jones at 3.

1 **Q12. WHAT COMMISSION ORDERS ARE IMPLICATED BY ELL'S APPLICATION?**

2 A. As to ELL's request to add capacity to its generation portfolio, it must comply with the
3 Commission's General Order dated September 20, 1983 (the "Capacity Certification
4 Order"), which requires utilities to demonstrate that capacity additions serve the public
5 convenience and necessity.¹⁴ Similarly, as ELL is seeking to construct new transmission
6 facilities, it must comply with the Commission's General Order dated September 10, 2024
7 (Docket No. R-36199), which requires certification of certain transmission facilities (the
8 "Transmission Certification Order").¹⁵ In addition, consideration must be given to the
9 Company's proposed satisfaction of the Commission's Lightning Initiative¹⁶ to determine
10 whether the certifications are exempt from the requirements of the Commission's Market
11 Base Mechanism Order (the "MBM Order"),¹⁷ which requires utilities to implement a
12 competitive bidding process when seeking new capacity. ELL additionally has sought (i)

¹⁴ LPSC General Order dated September 20, 1983 (*In re: In the Matter of the Expansion of Utility Power Plant; Proposed Certification of New Plant by the LPSC*), as amended by General Order (Corrected) in Docket No. R-30517 (*In re: Possible modifications to the September 20, 1983 General Order to allow (1) for more expeditious certifications of limited-term resource procurements and (2) an exception for annual and seasonal liquidated damages block energy purchases*) dated May 27, 2009.

¹⁵ LPSC General Order, Docket No. R-36199 (Sept. 10, 2024) (*In re: Review and Possible Modification of the Commission's General Order dated October 10, 2013 Governing Transmission Certification and General Siting*).

¹⁶ LPSC Minutes from December 17, 2025 Open Session, at pp. 6-7, available at https://lpsc.louisiana.gov/docs/minutes/Dec_17_2025_Min.pdf.

¹⁷ LPSC General Order, Docket No. R-26172, Subdocket A (Feb. 16, 2004) (*In re: Development of Market-Based Mechanisms to Evaluate Proposals to Construct or Acquire Generating Capacity to Meeting Native Load. Supplements the September 20, 1983 General Order*), as amended by General Order No. R-26172, Subdocket B (Nov. 3, 2006), further amended by the April 26, 2007 General Order, and further amended by General Order No. R-26172, Subdocket C (Oct. 29, 2008), and further amended by General Order 10-14-2024, Docket No. R-34247 (Oct. 14, 2024) ("MBM Order").

1 confirmation of its compliance with the Commission's General Order in dated July 29,
2 2019 (Docket No. R-34860) (The "Historical Footprint Rule") related to load increases
3 greater than 5% and (ii) interpretations of rulings on Commission General Order No. U-
4 36697, dated June 14, 2024, related to the alternative procurement process and expedited
5 certification for up to 3 GW of certain renewable resources (the "3GW Order").¹⁸

6 **Q13. IN YOUR OPINION, HAS ELL COMPLIED WITH THE PROCEDURAL**
7 **REQUIREMENTS OF THE COMMISSION'S CAPACITY CERTIFICATION**
8 **ORDER?**

9 A. Yes. The Commission's Capacity Certification Order requires any Commission-
10 jurisdictional electric public utility that proposes to construct or acquire capacity or to enter
11 into a contract for the purchase of capacity or energy (other than emergency or economy
12 energy) to apply to the Commission for certification that the public convenience and
13 necessity would be served through the proposed construction, acquisition, or contract. The
14 Capacity Certification Order also requires that applications submitted pursuant to that
15 Order include the specific data used by the utility in the justification of the acquisition,
16 construction, or power purchase agreement. In its Application, ELL has provided support
17 for its assertion that the Planned Generators serve the public convenience and necessity,
18 and therefore, its filing complies with the requirements of the Capacity Certification Order.
19 I will discuss whether the Commission should find that the addition of the Proposed

¹⁸ LPSC Order No. U-36697 (corrected) (June 14, 2024) (*In re: Application for Approval of an Alternative Market-Based Mechanism Process Seeking to Secure Up To 3,000 MW of Solar Resources, Including Certification of Those Resources, Expansion of the Geaux Green Option Rider, and Approval of a New Renewable Tariff*) ("3GW Order").

Generators and Battery Storage Facilities served the public convenience and necessity in Section IV below.

Q14. PLEASE DESCRIBE THE REQUIREMENTS OF THE MBM ORDER.

A. The MBM Order establishes various procedures and requirements for the market testing of all proposed capacity additions by jurisdictional utilities. It requires a utility proposing to add new generating capacity to “employ a market-based mechanism” consisting of a “Request for Proposal (‘RFP’) competitive solicitation process.” The MBM Order provides certain limited circumstances under which a formal RFP process is not required and provides a utility the option to “propose an alternative market-based mechanism or procedure if it can demonstrate that a formal RFP would not be in the public interest.”

Q15. PLEASE DESCRIBE THE LIGHTNING INITIATIVE.

A. The Lightning Initiative was approved by the Commission at the December 17, 2025, Business and Executive Session. It provides that the requirements of the MBM Order are waived for a proposed capacity addition where certain factors are demonstrated in the certification proceeding. I will discuss whether the Commission should find that the factors have been satisfied and thus the requirements of the MBM Order waived in Section III below.

Q16. HAS ELL COMPLIED WITH THE PROCEDURAL REQUIREMENTS FOR THE TRANSMISSION CERTIFICATION ORDER?

A. Mr. John A. Chapman addresses this in his Direct Testimony filed on behalf of the Staff contemporaneously with this testimony, and he concludes that ELL has complied with the procedural requirements of the transmission certification rules.

Q17. SHOULD THE COMMISSION CERTIFY THE TRANSMISSION AS SERVING THE PUBLIC CONVENIENCE AND NECESSITY AS REQUESTED BY ELL IN THIS APPLICATION?

A. I discuss ELL's request for the Commission to certify that the public convenience and necessity would be served through the construction and siting of the Transmission requiring certification proposed by ELL in Section IV below.

Q18. HAS ELL COMPLIED WITH THE REQUIREMENTS OF RULE 3 OF THE HISTORICAL FOOTPRINT ORDER FOR LOAD ADDITIONS GREATER THAN 5%?

A. Yes. Rule 3 of the Historical Footprint Order requires:

For utilities that participate in an IRP, prior to entering an electric service agreement with a customer which represents a projected increase in the peak load of that utility of an amount greater than 5% of the prior peak load, the utility must submit one of the following filings to the Commission, as warranted by the circumstances: (1) a filing which illustrates how the most recent IRP accommodates such load growth (e.g. the utility was long on generation and able to absorb the growth and still maintain an adequate margin), (2) a filing to update its IRP to illustrate how it plans to accommodate the new load growth, or (3) a filing pursuant to the MBM Order and/or the 1983 Order requiring Commission certifications for the acquisition of power supply. Entering into an electric service agreement subject to a condition precedent regarding compliance with this Rule shall not constitute a violation of this Rule.

ELL's most recent integrated Resource Plan ("IRP") was file in LPSC Docket No. U-37950. ELL's submission of the request for certification of the Planned Generators meets the requirements of this rule.

Q19. PLEASE DESCRIBE ELL'S REQUESTS REGARDING THE 3GW ORDER.

A. ELL's specific requests are that the Commission:

- Find that Evest is a "New Customer" as defined in 3GW Order.

- 1 • Find that the Customer qualifies for a Geaux Zero Group 3 Subscription for
2 purposes of securing approval, in the future, of the 2,500 MW of designated
3 Renewable Resources contemplated in Sustainability Agreement.
4
- 5 • Find that the Company can employ the expedited procurement and certification
6 procedures set forth in the 3GW Order to procure and seek certification of
7 Designated Renewable Resources.
8
- 9 • Approve the proposed protections and dispute resolution processes with respect
10 to Designated Renewable Resources that exceed the Breakeven Parameter set
11 forth in the 3GW Order.
12

13 I discuss these requests in Section V(B) below.

14 **II. ELL'S SUPPLY AND TRANSMISSION PLAN UNDERLYING ITS REQUESTS**
15 **FOR CERTIFICATION**

16 **Q20. WHAT DOES ELL PRESENT AS SUPPORT FOR THE NEED FOR THE**
17 **CAPACITY IT PROPOSES TO FILL WITH THE PROPOSED GENERATORS**
18 **AND THE OTHER SUPPLY PLAN RESOURCES?**

19 A. ELL's support for the need for the Proposed Generators and the Other Supply Plan
20 Resources is presented primarily through the testimony of Company witnesses Laura K.
21 Beauchamp. Ms. Beauchamp explains that the proposed Customer load requires ELL to
22 increase its available capacity resources to satisfy both its MISO resource adequacy
23 obligations and its broader obligation to reliably serve the Customer's projected demand.
24 She presents the Customer's projected maximum demand, expected contribution to
25 coincident peak, and the resulting increase in ELL's projected planning requirements.¹⁹
26 The Company's projected contribution to coincident peak is presented in Table 6 of Ms.

¹⁹ Direct Testimony of Laura K. Beauchamp at 10-13, 38-39; *see also* RLS-002 (ELL response to Staff Data Request 5-1).

1 Beauchamp's testimony and is further supported by the ELL Load and Capability Report
2 produced in response to Staff Data Request 1-1.²⁰

3 **Q21. DID YOU PREPARE ANY EXHIBITS TO ASSIST THE COMMISSION IN**
4 **UNDERSTANDING THE COMPANY'S NEED ANALYSIS?**

5 A. To assist the Commission in understanding the Company's need analysis, I prepared an
6 illustrative exhibit using the ELL Load and Capability Report produced in response to Staff
7 Data Request 1-1. The exhibit does not modify the Company's assumptions or
8 calculations. Rather, I added a tab to that workbook that calculates the incremental changes
9 reflected in the Company's own projections to more clearly illustrate the relationship
10 between the projected increase in Customer load and the incremental capacity resources
11 reflected in the Company's supply plan.²¹ In my opinion, the exhibit demonstrates that,
12 under the Company's own assumptions, additional capacity resources are necessary to
13 serve the projected increase in Customer load.

14 **Q22. WHAT DO YOU CONCLUDE ABOUT ELL'S PURPORTED NEED FOR**
15 **CAPACITY THAT IT PROPOSES TO FILL WITH THE PROPOSED**
16 **GENERATORS AND THE OTHER SUPPLY PLAN RESOURCES?**

17 A. My review of the Company's planning analyses confirms that, if the Commission accepts
18 the Company's representation of the projected Evest load and if ELL is to provide electric
19 service to that load as proposed, additional capacity resources will be required. Using the
20 Company's own load forecasts and planning assumptions, the incremental capacity

²⁰ RLS-012 (ELL Load and Capability Report) (HSPM).

²¹ RLS-003 (Calculation of Evest Impacts Comparing the Base and Change Cases Presented in ELL's Load and Capability Report Provided by ELL in Response to Staff 1-1).

1 requirement generally tracks the magnitude of the capacity resources for which ELL seeks
2 certification.

3 **Q23. WHAT DOES ELL PROPOSE FOR THE SUPPLY PLAN?**

4 A. ELL proposes to address the anticipated capacity requirements needed to serve Evest
5 through directly assigning the cost via a minimum bill a combination of newly constructed
6 generating resources, battery storage resources, and resources that were already planned
7 for the ELL system. Specifically, the Company's proposes to assign to Evest the annual
8 costs of:

- 9 • seven Proposed Generators;
- 10 • three Battery Storage Facilities;
- 11 • the Bayou Cove PCA; and
- 12 • the Waterford 3 uprate

13
14 According to ELL, the seven Proposed Generators represent approximately \$13 billion of
15 new generating investment.²² In addition, ELL estimates the three Battery Storage
16 Facilities will require approximately [REDACTED] billion of investment, consisting of
17 approximately [REDACTED] million of self-developed battery storage and approximately [REDACTED]
18 million of procured battery storage. ELL further estimates the cost of the Waterford 3
19 uprate at approximately [REDACTED] million and the Bayou Cove PCA at approximately [REDACTED]
20 billion.²³

21 ELL's planning analysis reflects two related, but distinct, planning metrics. The first is
22 based on the Customer's projected contribution to coincident peak together with the
23 applicable MISO Planning Reserve Margin Requirement ("PRMR"). The second is based

²² Direct Testimony of Norman Grunden at 19-20.

²³ Exhibit LKB-3 CIAC, Exhibit F-2 (AEO).

1 on the Customer's projected maximum demand and the amount of capacity ELL proposes
2 to have available in support of serving that demand.

3 Ms. Beauchamp explains that ELL evaluated the supply plan against both the MISO
4 resource adequacy construct, identified as the Customer's coincident peak contribution
5 plus the PRMR, and the Customer's maximum demand on a standalone basis, identified as
6 ■■■ MW plus a reserve margin.²⁴ She separately identifies the Customer's maximum
7 demand in Q39 and its expected contribution to coincident peak in Q40 and Table 6.²⁵ The
8 Company also explains in response to Staff Data Request 5-1 that the Proposed Generators
9 and Battery Storage Facilities address MISO's planning requirements associated with
10 Evest, while the broader supply plan addresses the Customer's maximum demand,
11 particularly through the inclusion of the Bayou Cove PCA and the Waterford 3 uprate.²⁶

12 Accordingly, as reflected in the Company's planning analysis, ELL proposes the
13 Proposed Generators and Battery Storage Facilities as the principal capacity additions
14 associated with the coincident-peak-plus-PRMR metric, while also including the Bayou
15 Cove PCA and the Waterford 3 uprate in its overall supply plan in connection with the
16 maximum-demand metric.

17 At this point, I am merely describing the structure of ELL's proposed supply plan
18 assignment to Evest and not offering an opinion regarding whether the proposed resources
19 are sufficient, appropriately timed, or otherwise satisfy the Commission's certification
20 standards.

²⁴ Direct Testimony of Laura K. Beauchamp at 104.

²⁵ *Id.* at 38-39.

²⁶ RLS-002 (ELL Response to Staff Data Request 5-1).

1 **Q24. PLEASE DISCUSS HOW ELL DEVELOPED ITS SUPPLY PLAN.**

2 A. ELL describes the proposed supply plan as the product of an integrated generation and
3 transmission planning process developed specifically for large hyperscale data center
4 projects. According to Mr. Heytens, ELL departed from its traditional transmission-
5 focused planning approach and instead implemented “a coordinated planning process for
6 developing an integrated supply solution” that combined generation and transmission
7 planning because serving a customer of Evest’s size required both new generating
8 resources and new transmission infrastructure. He further explains that the revised
9 planning process embedded both generation and transmission execution teams early in the
10 planning process so that equipment availability, lead times, cost estimates, and schedule
11 feasibility could be evaluated in real time.²⁷

12 Ms. Beauchamp explains that ELL’s general resource-planning process begins
13 with: (1) an assessment of the capability of the Company’s existing resources; (2) a forecast
14 of the peak load, reserve margin, and energy requirements expected over the planning
15 horizon; and (3) a determination of the amount and types of additional supply-side and
16 demand-side resources needed to meet those requirements. She states that ELL ordinarily
17 seeks to balance reliability, affordability, and sustainability, but that development of the
18 Evest supply plan was also materially influenced by the Customer’s requested speed to
19 market.²⁸

20 Applying that process to Evest, ELL began with the Customer’s proposed
21 maximum demand of [REDACTED] MW, expected [REDACTED] load factor, anticipated annual energy

²⁷ Direct Testimony of Troy Heytens at 3-7.

²⁸ Direct Testimony of Laura Beauchamp at 45-50.

1 consumption of approximately [REDACTED], seasonal coincident-peak contributions,
2 and proposed ramp to full load. ELL then evaluated alternative combinations of
3 generation, storage, and transmission resources and selected seven 1x1 CCCTs and [REDACTED]
4 MW of battery storage as the principal new supply resources.²⁹

5 Mr. Owens provides the Company's principal explanation for the number and type
6 of generation resources selected. According to Mr. Owens, ELL first determined that at
7 least seven CCCTs were needed to address the incremental around-the-clock energy
8 requirements associated with the Customer's projected load. He compares the Customer's
9 expected annual consumption - [REDACTED] with the
10 energy ELL expected seven CCCTs to produce at an assumed annual capacity factor of
11 approximately [REDACTED].³⁰ ELL concluded that six or fewer CCCTs would not produce
12 sufficient energy under those assumptions. Rather than add an eighth CCCT to address the
13 remaining capacity requirement, ELL selected battery storage because it considered storage
14 less capital intensive and capable of entering service more quickly.³¹

15 Mr. Owens further explains that ELL considered other potential means of
16 addressing the Customer's around-the-clock requirements but concluded that they were
17 either unavailable on the Customer's required schedule or inferior for purposes identified
18 by ELL. In particular, he states that new nuclear generation could not be planned,
19 permitted, and constructed in time; simple-cycle combustion turbines would be less
20 efficient than CCCTs; and wind, solar, and storage could not provide an around-the-clock

²⁹ *Id.* at 38-42.

³⁰ Direct Testimony of Nicholas Owens at 4-5.

³¹ *Id.*

1 energy profile comparable to the proposed CCCTs without what ELL considered an
2 impracticably large amount of storage. He also states that ELL elected not to rely
3 principally on its existing fleet and wholesale-market purchases because doing so would
4 expose the Company to higher-cost energy from the spot market and increased operation
5 of less-efficient existing units.³²

6 Ms. Beauchamp similarly identifies three more specific supply-plan alternatives
7 evaluated by ELL: an all-CCCT plan with minimal transmission and no renewable
8 resources; the use of a 2x1 CCCT configuration in place of certain 1x1 units; and a
9 transmission-only solution. ELL represents that each alternative was determined to be
10 infeasible or inferior to its proposed combination of generation, battery storage, and
11 transmission.³³

12 After ELL determined the type and general quantity of resources, Mr. Kline and the
13 Power Delivery Planning team evaluated where the CCCTs should be located and how the
14 generation and transmission plans would operate together. Mr. Kline explains that his team
15 provided siting feedback intended to develop an integrated generation-and-transmission
16 plan that could accommodate both the Evest load and the associated capacity and energy
17 resources.³⁴

18 According to Mr. Kline, four 1x1 CCCTs were located adjacent to the Customer's
19 load at West Fork Creek to reduce the net load imposed on the transmission system and
20 mitigate the need for additional transmission upgrades. The remaining three CCCTs were

³² *Id.* at 6-8.

³³ Direct Testimony of Laura Beauchamp at 77-80.

³⁴ Direct Testimony of Daniel Kline at 40-41.

1 located in South Louisiana at the existing Big Cajun site to use available land and [REDACTED]
2 [REDACTED], thereby
3 reducing the time and uncertainty associated with obtaining deliverability for the new
4 generation.³⁵

5 Mr. Kline's team then studied the generation assumptions together with the
6 proposed Evest load under three principal transmission scenarios and related sensitivities.
7 Those scenarios changed as the projected load and proposed generation configuration
8 evolved, including scenarios involving a [REDACTED] MW load and four CCCTs and the final
9 [REDACTED] MW load with four CCCTs at West Fork Creek and three CCCTs in South Louisiana.
10 ELL used those studies to identify the transmission additions that it represents are required
11 to interconnect the resources, deliver power to the Customer, and address the resulting
12 thermal, voltage, operational, and reliability conditions.³⁶

13 Thus, as ELL describes the process, the projected load level and operating profile
14 were used to determine the overall capacity and energy requirements; those requirements
15 were used to select the number and types of generation and storage resources; and the
16 Power Delivery Planning team then used transmission studies, interconnection availability,
17 land availability, reliability considerations, and the Customer's requested schedule to
18 determine the proposed locations and supporting transmission configuration.

19 At this point, I am describing the process and rationale presented by ELL and am
20 not offering an opinion on whether that process, the alternatives considered, or the resulting
21 supply plan were reasonable or sufficient.

³⁵ *Id.* at 40; *see also* RLS-004 (ELL HSPM response to Staff Data Request 1-75).

³⁶ Direct Testimony of Daniel Kline at 42-43.

1 **Q25. PLEASE DESCRIBE THE TRANSMISSION PLAN THAT RESULTED FROM**
2 **THAT PROCESS.**

3 A. Similar to the proposed supply plan, ELL describes its proposed transmission plan as the
4 product of an iterative planning process that evolved as the projected Customer load,
5 generation portfolio, and transmission studies were refined. According to Mr. Kline, ELL
6 evaluated multiple planning scenarios reflecting changes in the projected Customer load,
7 the location and quantity of the proposed generation resources, and the resulting
8 transmission system impacts before arriving at the transmission configuration included in
9 the Application.³⁷

10 ELL's final transmission plan consists of four principal components:

- 11 • the Customer-Funded Transmission Interconnection Project;
- 12 • the Customer-Funded Smalling-El Dorado 500-kV Transmission Line;
- 13 • the ELL Funded WFC-St. Landry 500-kV Transmission Line and St. Landry
- 14 Switching Station; and
- 15 • the transmission facilities required to provide construction and commissioning
- 16 power.

17
18 Collectively, ELL estimates the proposed transmission facilities will require approximately
19 [REDACTED] of investment, of which approximately [REDACTED] would be funded directly
20 by the Customer through CIAC arrangements and approximately \$1.5 billion would be
21 funded by ELL.³⁸

22 ELL provides comparatively little discussion regarding the analytical basis for either
23 the Customer-Funded Transmission Interconnection Project or the Customer-funded

³⁷ *Id.* at 35-45.

³⁸ *Id.* at 31.

1 transmission facilities required to provide construction and commissioning power. Instead,
2 Mr. Kline primarily describes these facilities as the physical transmission infrastructure
3 necessary to interconnect the Customer's facilities and the proposed generation resources
4 with the ELL transmission system.³⁹ Unlike the Smalling–El Dorado and WFC–St. Landry
5 transmission projects, ELL does not present these facilities as the product of alternative
6 transmission planning scenarios or detailed transmission analyses. This is consistent with
7 the limited purpose these facilities serve, namely providing the physical interconnection
8 necessary to connect the Customer and the proposed generation resources to the existing
9 transmission system. Because ELL represents that these facilities will be funded entirely
10 by the Customer through the applicable CIAC arrangements and related Customer
11 Agreements, ELL is not requesting that the Commission certify these facilities.

12 The Customer-Funded Transmission Interconnection Project and the facilities
13 providing construction and commissioning power principally serve to physically connect
14 the Customer and the proposed generation resources to the ELL transmission system. By
15 contrast, the Customer-Funded Smalling-El Dorado transmission line was identified
16 through ELL's transmission planning studies as a bulk transmission solution intended to
17 address system reliability concerns created by the proposed load and generation
18 configuration. Mr. Kline explains that this project strengthens the existing 500-kV
19 transmission network between North Louisiana and South Arkansas and will likewise be
20 funded directly by the Customer through CIAC arrangements. According to Mr. Kline, as
21 reflected in ELL's transmission planning studies, the Smalling-El Dorado line was
22 identified during the Company's first planning scenario as necessary to address thermal

³⁹ *Id.* at 13-14.

1 constraints on existing transmission facilities and to maintain NERC TPL-001 compliance
2 under the assumed load and generation configuration.⁴⁰

3 ELL further proposes construction of the WFC-St. Landry 500-kV Transmission
4 Line and the associated St. Landry Switching Station and proposes that these assets be
5 funded by ELL, with off-setting revenue contributions from Evest during the term of the
6 ESA. Unlike the Smalling-El Dorado project, Mr. Kline explains that this facility was
7 identified during ELL's second planning scenario after the initial thermal constraints
8 identified in the first planning scenario had been addressed. According to Mr. Kline, the
9 WFC-St. Landry project was ultimately proposed to improve operational flexibility,
10 facilitate planned maintenance outages, support continued reliability during extreme
11 weather and generation outages, and reduce reliance on operational measures such as
12 delaying or cancelling planned maintenance. Mr. Kline acknowledges that this project is
13 not presently required to satisfy existing NERC planning standards, but explains that, in
14 ELL's judgment, the project is necessary to permit essential seasonal maintenance outages,
15 maintain operational flexibility, support continued reliability during extreme weather and
16 generation outages, and avoid relying on operational measures such as delaying or
17 cancelling planned maintenance.⁴¹ ELL reiterated these positions in response to Staff Data
18 Requests 1-120 through 1-133, explaining that the proposed WFC-St. Landry line reflects
19 the Company's planning judgment rather than a presently applicable NERC requirement.⁴²

⁴⁰ *Id.* at 43-44.

⁴¹ *Id.* at 21-29, 45.

⁴² RLS-005 (ELL responses to Staff Data Requests 1-120 through 1-133 (excludes ELL's response 1-125 due to CEII information included in that response)).

1 Finally, Mr. Kline explains that ELL evaluated a third planning scenario
2 incorporating additional changes to the projected load and generation assumptions.
3 According to ELL, this scenario did not identify any additional transmission upgrades
4 beyond those identified in the first two scenarios, but instead confirmed the robustness of
5 the proposed transmission configuration. ELL therefore concluded that the transmission
6 facilities identified through the first two scenarios should comprise the proposed
7 transmission plan submitted for Commission review.⁴³

8 Accordingly, ELL represents that its proposed transmission plan is intended to
9 provide more than a physical interconnection for Project Evest. Rather, ELL contends that
10 the proposed facilities constitute an integrated transmission solution designed to
11 accommodate the projected Customer load, support the proposed generation portfolio,
12 maintain system reliability, while satisfying the Company's planning objectives.

13 At this point in my testimony, I am describing the transmission plan and the
14 rationale presented by ELL and am not offering an opinion as to whether the proposed
15 transmission facilities are necessary or whether they satisfy the Commission's certification
16 standards.

17 III. MBM ORDER/ LIGHTNING INITIATIVE

18 **Q26. WHAT IS THE COMMISSION'S TRADITIONAL APPROACH TO** 19 **CERTIFICATION OF NEW GENERATION?**

20 A. Under the Commission's traditional certification framework, a utility seeking certification
21 of new generation is generally expected to demonstrate both the need for the proposed
22 resources and that the proposed resources represent a reasonable means of satisfying that

⁴³ Direct Testimony of Daniel Kline at 45-46.

1 need. Pursuant to the Commission's Market Based Mechanism Order ("MBM Order"),
2 that demonstration ordinarily requires the results of a defined MBM process intended to
3 provide the Commission with information regarding available market alternatives. The
4 MBM Order also permits a utility to propose an alternative mechanism for Commission
5 consideration *in lieu* of a traditional MBM process. Utilities have also requested waivers
6 from the requirement in the past with support for their request and only been granted such
7 waivers in extraordinary circumstances.

8 **Q27. HAS ELL REQUESTED APPROVAL PURSUANT TO THE MBM ORDER, OR**
9 **OF AN ALTERNATIVE MBM MECHANISM IN THIS PROCEEDING?**

10 A. No. Rather than requesting approval in accordance with the MBM Order or proposing an
11 alternative MBM mechanism under the MBM Order, ELL requests that the Commission
12 waive the MBM requirement pursuant to the Commission's Lightning Initiative.

13 **Q28. WHAT IS THE COMMISSION'S LIGHTNING INITIATIVE?**

14 A. The Lightning Initiative provides that the requirements of the MBM Order are considered
15 waived when a utility demonstrates five specified factors during the certification
16 proceeding ("Lightning Initiative Waiver"). In addition to providing a waiver from the
17 MBM Order, satisfaction of these factors allows for an expedited review process which is
18 requested in this Application. The directive further provides that nothing in the Initiative
19 relinquishes the Commission's authority to determine whether the proposed capacity
20 additions serve the public interest or to evaluate the prudence of the utility's procurement,
21 construction, or contract administration. Likewise, the Lightning Initiative expressly
22 preserves the right of interested parties to participate in the certification proceeding.

1 **Q29. DOES A UTILITY HAVE THE UNILATERAL RIGHT TO INVOKE THE**
2 **LIGHTNING INITIATIVE WAIVER?**

3 A. No. The utility may file a request for application of the Lightning Initiative Waiver, but
4 they must support it, and the Commission must determine that they meet the requirements
5 for such waiver within the application where they make the request.

6 **Q30. WHAT ARE THE REQUIREMENTS FOR OBTAINING A LIGHTNING**
7 **INITIATIVE WAIVER?**

8 A. The Commission identified five principal requirements in its Lightning Initiative:

- 9 1. A signed electric service agreement (“ESA”) with a new or expanding load with a
10 requested initial in-service date within five years of the certification application;
- 11 2. Without the proposed capacity, the utility is projected to be short of the energy or
12 capacity needed to meet the customer’s electric requirements on the requested in-
13 service dates;
- 14 3. A letter from the Secretary of Louisiana Economic Development confirming the in-
15 service date and the importance of power availability within the five year initial in-
16 service date;
- 17 4. The ESA has a term of at least 15 years, with an option to renew; and
- 18 5. The ESA ensures a level of fixed revenue over the term of the ESA that will cover
19 at least one-half of the fixed revenue requirement associated with the requested
20 capacity during the term of the customer ESA.

21 **Q31. HAS ELL SATISFIED THE FIRST REQUIREMENT?**

22 A. Yes. ELL has presented a signed ESA that meets the requirements of the Directive.
23 Accordingly, I conclude that ELL has satisfied this requirement.

24 **Q32. HAS ELL SATISFIED THE SECOND REQUIREMENT?**

25 A. Yes. As presented above and discussed more below, without the proposed capacity ELL
26 is projected to be short of the energy or capacity it needs to meet the customer’s electric

1 needs on the requested in-service date. Accordingly, I conclude that ELL has satisfied this
2 requirement.

3 **Q33. HAS ELL SATISFIED THE THIRD REQUIREMENT?**

4 A. Yes. ELL submitted the letter from the Secretary of the Louisiana Department of
5 Economic Development required by the Lightning Initiative.⁴⁴ In that letter, the Secretary
6 confirms Evest's interest in making the proposed investment in Richland Parish and
7 confirms the importance of power availability within the five-year timeframe specified by
8 the Lightning Initiative. Accordingly, I conclude that ELL has satisfied this requirement.

9 **Q34. HAS ELL SATISFIED THE FOURTH REQUIREMENT?**

10 A. Yes. The ESA provides for an initial twenty-year term together with the renewal provisions
11 required by the Commission.⁴⁵ Accordingly, I conclude this requirement has been satisfied.

12 **Q35. HAS ELL SATISFIED THE FIFTH REQUIREMENT?**

13 A. Yes. Based on the analyses presented by ELL, which I will discuss in my review of ELL's
14 adherence to the Commission's Large Load Guidelines ("Large Load Guidelines"), I
15 conclude that the projected fixed revenues to be received under the Customer Agreements
16 exceed the Commission's fifty percent (50%) threshold for purposes of the Lightning
17 Initiative Waiver.

18 It is important, however, to recognize the purpose of this requirement. The
19 Commission adopted the fifty-percent threshold solely as a criterion for determining
20 eligibility for a waiver of the MBM requirements and access to the expedited review
21 process afforded by the Lightning Initiative. Fifty percent is not and should not be

⁴⁴ Exhibit RDJ-5 to the Direct Testimony of Ryan D. Jones.

⁴⁵ Exhibit LKB-2 at 2 of 123.

1 considered an established standard by which the Commission determines whether the costs
2 and risks associated with serving a large load have been appropriately allocated or whether
3 existing customers are adequately protected. Those broader considerations are addressed
4 through the Commission's certification proceeding and, in this docket, are further informed
5 by the Commission's Large Load Guidelines. My discussion of those issues begins in
6 Section IV.C. of my testimony.

7 **Q36. WHAT IS YOUR OVERALL CONCLUSION REGARDING ELL'S REQUEST**
8 **FOR A LIGHTNING INITIATIVE WAIVER?**

9 A. Based on my review of the information provided by ELL, I conclude that ELL has
10 demonstrated compliance with each of the requirements established by the Commission's
11 Lightning Initiative for a waiver of the MBM requirements. Accordingly, I recommend
12 that the Commission grant ELL's request for a waiver of the MBM requirements and allow
13 this proceeding to continue under the expedited review process established by the
14 Lightning Initiative.

15 It is important to recognize, however, that the Lightning Initiative was intended
16 only to establish an alternative procedural pathway *in lieu* of the traditional MBM process.
17 The Lightning Initiative expressly provides that nothing therein relinquishes the
18 Commission's authority to determine whether the proposed capacity additions serve the
19 public interest or to evaluate the prudence of the utility's procurement, construction, or
20 contract administration. Likewise, the Lightning Initiative expressly preserves the right of
21 interested parties to participate in the certification proceeding. Accordingly, my conclusion
22 that ELL has satisfied the requirements of the Lightning Initiative should not be interpreted
23 as a recommendation that the Commission approve the requested certifications. Rather, it

1 simply reflects my conclusion that ELL has satisfied the procedural requirements necessary
2 to obtain a waiver of the MBM process. The Commission must still determine whether the
3 proposed generation and transmission facilities satisfy the applicable certification
4 standards, serve the public interest, and adequately protect existing customers. I address
5 those issues in the remainder of my testimony.

6 **IV. ELL'S GENERATION AND TRANSMISSION CERTIFICATION REQUESTS**

7 **A. STANDARD OF REVIEW**

8 **Q37. HOW IS STAFF APPROACHING ELL'S REQUEST FOR CERTIFICATION OF**
9 **THE PROPOSED GENERATION AND TRANSMISSION FACILITIES?**

10 A. Although ELL requests certification of both generation and transmission facilities under
11 separate Commission Orders, I have generally considered those requests together because
12 ELL planned the proposed generation resources and transmission facilities as an integrated
13 solution to serve the projected Evest load and is proposing to directly assign the annual
14 costs to Evest through the MMCs. Consequently, the justification for the proposed
15 generation resources frequently depends on the proposed transmission facilities, and vice
16 versa. Accordingly, where appropriate, I discuss the two certification requests together in
17 evaluating whether they satisfy the applicable Commission standards.

18 **Q38. WHAT IS THE COMMISSION'S TRADITIONAL CERTIFICATION ANALYSIS?**

19 A. Traditionally, a certification proceeding for both generation and transmission involves two
20 principal inquiries. First, the Commission considers whether there is a demonstrated need
21 for the proposed facilities. Second, if such a need exists, the Commission considers
22 whether the proposed facilities represent an appropriate means of satisfying that need at
23 the lowest reasonable cost consistent with the public interest. That inquiry typically

1 includes consideration of whether the proposed facilities are reasonably designed,
2 appropriately sized and located, and whether they represent a reasonable and cost-effective
3 means of meeting the identified need.

4 **Q39. DOES THIS PROCEEDING PRESENT ANY ADDITIONAL CONSIDERATIONS?**

5 A. Yes. Project Evest represents an unprecedented electric load for the State of Louisiana and
6 requires substantial generation and transmission investments that are being proposed
7 primarily to serve a single customer. Recognizing the unique issues presented by projects
8 of this magnitude, the Commission recently adopted its Large Load Guidelines⁴⁶ to assist
9 in evaluating whether the risks associated with serving such extraordinary loads are
10 appropriately addressed. The Large Load Guidelines provide transparency to utilities,
11 potential large load customers, and the public on known areas of concern for the
12 Commission regarding potential large load. In any proceeding regarding large load
13 additions, the Large Load Guidelines are to be addressed and will be part of the
14 Commission's analysis. Accordingly, and in addition to the traditional certification
15 analysis, I have considered ELL's Application in light of those Large Load Guidelines.

16 **Q40. WHAT ROLE DO THE CUSTOMER AGREEMENTS, INCLUDING THE ESA,**
17 **PLAY IN YOUR ANALYSIS?**

18 A. ELL relies extensively on the Customer Agreements - including the ESA, the CIAC
19 Agreement, Rider 1, the Terms and Conditions, and related agreements - to demonstrate
20 that the issues identified in the Commission's Large Load Guidelines have been addressed.
21 Those agreements contain many of the contractual provisions on which ELL relies in

⁴⁶ LPSC Minutes from February 25, 2026 Open Session, at p. 6, *available at*
https://lpsc.louisiana.gov/docs/minutes/Feb_25_2026_Min.pdf.

1 support, including provisions relating to minimum monthly charges, customer funding
2 obligations, financial security, termination rights, cost recovery, and other customer
3 protections. Accordingly, consideration of those agreements is necessary to evaluate many
4 of ELL's claims concerning the adequacy of the protections proposed to satisfy the
5 Commission's Large Load Guidelines.

6 **Q41. IS ELL ASKING THE COMMISSION TO APPROVE THE ESA?**

7 A. No. Mr. Jones expressly states, "The Company is not asking the Commission to approve
8 the terms of the ESA".⁴⁷ He explains that the ESA is not a site-specific contract subject to
9 Commission approval and that the Customer will instead take service under ELL's filed
10 tariff, with the ESA containing provisions that generally provide additional protections for
11 existing customers rather than customer-specific discounts.⁴⁸ I agree with that position.
12 Staff is not recommending that the Commission approve, reject, or otherwise endorse the
13 ESA or the other Customer Agreements. Rather, those agreements have been provided
14 because ELL relies on them to support its requests for certification and to demonstrate how
15 it proposes to satisfy the concerns reflected in the Commission's Large Load Guidelines.

16 **Q42. IF STAFF IS NOT RECOMMENDING APPROVAL OF THE ESA, WHY DOES**
17 **YOUR TESTIMONY DISCUSS ITS PROVISIONS IN DETAIL?**

18 A. Because ELL has affirmatively relied on the Customer Agreements to demonstrate that the
19 proposed generation and transmission facilities serve the public interest and that the risks
20 associated with serving Project Evest are appropriately allocated as envisioned by the
21 Commission's Large Load Guidelines, the Staff must review those agreements in order to

⁴⁷ Direct Testimony of Ryan Jones at 53-54.

⁴⁸ *Id.*

1 evaluate the specific claims ELL has made in support of its certification requests.
2 Accordingly, my discussion of the Customer Agreements is limited to evaluating whether
3 the record supports ELL's representations regarding the protections those agreements are
4 intended to provide and whether additional protections or conditions should be considered
5 by the Commission.

6 My review should not be interpreted as a recommendation that the Commission
7 approve, ratify, or otherwise endorse the Customer Agreements or any of their individual
8 terms or provisions. Nor should it be interpreted as a determination that ELL prudently
9 negotiated those agreements or that the agreements adequately protect existing customers
10 under all future circumstances. Staff was not a participant in the negotiation of these
11 extraordinarily complex agreements, and the limited review conducted during the
12 expedited Lightning Initiative schedule should not be construed as an exhaustive evaluation
13 of every contractual provision or every potential future risk.

14 ELL remains fully responsible for the prudence of the agreements it negotiated,
15 including the adequacy of the contractual protections provided to existing customers, the
16 allocation of risks between the Customer and ELL, and ELL's implementation,
17 administration, and enforcement of those agreements. If future events demonstrate that the
18 Customer Agreements do not provide the protections ELL represents they provide, that
19 they are insufficient to adequately protect ratepayers, or that ELL otherwise failed to
20 prudently negotiate, implement, administer, or enforce those agreements, nothing in this
21 proceeding should be construed as limiting the Commission's ability to evaluate those
22 matters in a future prudence proceeding or to determine the appropriate allocation of any
23 resulting costs or damages which the Commission finds.

1 My review is intended solely to assist the Commission in determining whether
2 ELL's present certification requests satisfy the applicable certification standards as
3 supplemented with the Commission's Large Load Guidelines and to evaluate the specific
4 representations ELL has made regarding the protections it contends are afforded by the
5 Customer Agreements.

6 **B. REVIEW OF THE PROPOSED CAPACITY SUPPLY AND**
7 **TRANSMISSION PLANS**

8 **Q43. PLEASE PROVIDE YOUR ANALYSIS OF THE NEED FOR THE PROPOSED**
9 **GENERATORS AND OTHER SUPPLY PLAN RESOURCES.**

10 A. Based on my review of the facts presented and discussed in Question 22 above, I conclude
11 that ELL has adequately demonstrated that, if ELL is to provide the level of electric service
12 contemplated by the Customer Agreements, additional capacity resources will be required.
13 Accordingly, ELL has established the need for additional capacity generally consistent
14 with the magnitude of the proposed generation resources for which it seeks certification.

15 The existence of a need for additional capacity, however, does not by itself establish
16 that the particular resources selected by ELL are the appropriate means of satisfying that
17 need. That determination requires consideration of ELL's proposed resource portfolio, the
18 associated transmission facilities, and the manner in which ELL proposes to address the
19 risks associated with serving Project Evest.

20 **Q44. PLEASE PROVIDE YOUR ANALYSIS OF THE NEED FOR THE PROPOSED**
21 **TRANSMISSION FACILITIES.**

22 A. Similar to the proposed generation resources, my evaluation of the proposed transmission
23 facilities cannot be performed independently of ELL's overall certification proposal. As
24 discussed in Question 25 above, ELL developed the proposed generation resources and

1 transmission facilities as an integrated solution to serve Project Evest, and the justification
2 for each depends, in substantial part, on the other.

3 Moreover, because the requested facilities are being proposed primarily to serve a
4 single extraordinary large load, my evaluation of both the proposed generation resources
5 and the proposed transmission facilities is necessarily guided by the Commission's Large
6 Load Guidelines.

7 **C. LARGE LOAD GUIDELINES.**

8 **Q45. PLEASE PROVIDE THE HISTORY OF THE COMMISSION'S LARGE LOAD**
9 **GUIDELINES.**

10 A. At the February 25, 2026 Business and Executive Session, the Commission passed a
11 directive without opposition establishing guidelines to address recurring issues that
12 utilities should consider when proposing the interconnection of large load customers. The
13 directive stated that in any proceedings regarding large load additions, the areas of concern
14 identified in the guidelines would be part of the Commission's analysis and that any utility
15 seeking Commission action in such a proceeding should be prepared to explain how each
16 issue presented in the guidelines has been addressed, or explain why the proposal would
17 still be in the public interest without addressing the Commission's known concerns
18 outlined in the guidelines.⁴⁹

19 **Q46. BEFORE DISCUSSING EACH OF THE COMMISSION'S LARGE LOAD**
20 **GUIDELINES, WOULD IT BE HELPFUL TO FIRST SUMMARIZE THE**

⁴⁹ LPSC Minutes from February 25, 2026 Open Session, at p. 6, *available at*
https://lpsc.louisiana.gov/docs/minutes/Feb_25_2026_Min.pdf.

**PRINCIPAL PROTECTIONS ELL CONTENDS ADDRESS THOSE
GUIDELINES?**

A. Yes. As discussed above, ELL relies extensively on the Customer Agreements and related testimony to demonstrate that the concerns reflected in the Commission's Large Load Guidelines have been adequately addressed. Those protections are not contained in any single document or witness's testimony. Rather, they are distributed throughout the Customer Agreements and the testimony of multiple Company witnesses. Accordingly, before evaluating each of the Commission's Large Load Guidelines individually, I believe it is helpful to first summarize the principal contractual provisions, operational protections, financial commitments, and other measures ELL relies on in support of its certification requests. Doing so provides a useful framework for understanding both ELL's position and my subsequent evaluation of those claims under each of the Commission's Large Load Guidelines.

**Q47. WHAT ARE THE PRINCIPAL PROTECTIONS ELL CONTENDS ADDRESS
THE COMMISSION'S LARGE LOAD GUIDELINES?**

A. Although the specific protections are discussed throughout the testimony of numerous Company witnesses, I generally categorize ELL's principal proposed protections into the following areas:

1. Customer funding of generation and transmission facilities through the CIAC Agreement and the Long Lead Agreements;
2. Minimum Monthly Charges (the "MMC" or "MMCs") established under Rider 1 intended to recover a substantial portion of the costs of the assigned generators, batteries, and other fixed costs associated with the serving Evest;

3. Contractual provisions governing early termination, including [REDACTED]
[REDACTED] and other contractual remedies;
4. A twenty-year initial ESA term, together with renewal provisions and continuing MMCs following renewal;
5. Three-year advance notice requirements applicable to non-renewal;
6. Customer obligations associated with the planned load ramp, including provisions permitting interruption of certain load under specified circumstances;
7. Parent guarantees and other financial security supporting the Customer's contractual obligations;
8. Technical and operational protections intended to mitigate reliability impacts associated with serving Project Evest, including provisions addressing flicker, harmonics, oscillation, and other power quality considerations;
9. Economic commitments and customer-funded benefits identified throughout the information provided by ELL, including projected customer revenues, contributions to Power to Care and energy efficiency programs, funding for nuclear and carbon capture studies, Waterford 3 operational enhancements, accelerated depreciation of certain facilities, and the broader economic analyses presented by ELL.

The extent to which these provisions adequately address the Commission's concerns varies depending on the particular Large Load Guideline under consideration. Accordingly, I discuss each of these protections in greater detail as they become relevant in my evaluation of the individual Large Load Guidelines.

1 **Q48. YOUR REVIEW BELOW DOES NOT FOLLOW THE NUMERICAL ORDER OF**
2 **THE COMMISSION'S LARGE LOAD GUIDELINES. WHY?**

3 A. The Commission's Large Load Guidelines identify the issues the Commission should
4 consider in evaluating proposals to serve large loads. The numerical order of the Large
5 Load Guidelines is not intended to prescribe the order in which those issues must be
6 analyzed. For purposes of my testimony, I have grouped the Large Load Guidelines in a
7 manner that I believe most clearly presents the issues before the Commission. I first
8 address the physical and operational feasibility of serving Project Evest, including the
9 characteristics of the proposed load, resource adequacy, transmission, fuel supply,
10 environmental considerations, load ramp, operational control, power quality, and planning
11 impacts. I then address the economic protections proposed for existing customers,
12 including ELL's proposed rate design, cost recovery mechanisms, and protections against
13 stranded asset risk. Finally, I discuss the ongoing oversight proposed by ELL. This
14 organization does not alter the substance of the Commission's Large Load Guidelines.
15 Rather, it is intended to present the issues in the sequence in which they naturally arise in
16 evaluating ELL's certification requests.

17 **1. LARGE LOAD GUIDELINE #1: NEED, SCOPE, AND LOAD**
18 **CHARACTERISTICS**

19 **Q49. WHAT DOES THE COMMISSION'S FIRST LARGE LOAD GUIDELINE**
20 **ADDRESS?**

21 A. The first Large Load Guideline addresses whether the utility has adequately defined the
22 proposed load and evaluated the operational characteristics of that load for planning
23 purposes. Specifically, the Large Load Guideline provides that the proposed load addition
24 needs to be clearly defined as to:

- Maximum Demand (MW)
- Annual Energy Consumption (MWh)
- Load Factor and Operating Profile
- Coincident Peak Contribution
- Expected ramp Schedule

The load profile needs to be evaluated under:

- Peak and off-Peak conditions
- Seasonal Extremes
- Abnormal system stress scenarios

**Q50. PLEASE PROVIDE YOUR ANALYSIS OF ELL'S COMPLIANCE WITH THIS
LARGE LOAD GUIDELINE.**

A. In my opinion, ELL has adequately addressed the matters identified in this Large Load Guideline.

With respect to the definition of the proposed load, Ms. Beauchamp identifies the Customer's maximum demand as [REDACTED] MW, explains that the Customer is expected to operate on a nearly continuous basis at a [REDACTED] % load factor, and calculates the resulting annual energy consumption at approximately [REDACTED] MWh.⁵⁰ Ms. Beauchamp separately provides the projected contribution of the Evest load to ELL's coincident peak for each MISO season from 2026 through 2050 in Table 6 of her direct testimony.⁵¹

The anticipated operating profile and ramp schedule are also described in the information provided by ELL. Ms. Beauchamp explains that construction power is expected to begin in [REDACTED], commissioning power in approximately [REDACTED], and the

⁵⁰ See Direct Testimony of Laura K. Beauchamp at 38.

⁵¹ *Id.* at 38–39.

1 Customer's load ramp in [REDACTED], reaching full demand in [REDACTED].⁵² Appendix C to Exhibit
2 LKB-2 further identifies the quantities of total and non-firm load the Customer may take
3 during each month of the ramp period. ELL confirmed in response to Staff Data Request
4 1-108 that Appendix C reflects the operative ramp schedule, including the quantity of load
5 permitted at various points and [REDACTED].⁵³

6 ELL also produced detailed load-forecast workpapers. In response to Staff Data
7 Request 1-66, ELL provided the Customer's hourly, monthly, and annual load forecasts
8 for the ESA term, together with the underlying load-factor assumptions and supporting
9 calculations.⁵⁴ Mr. Datta explains that the AURORA production-cost analysis used the
10 Customer's hourly load forecast throughout the ramp and over the full term of the ESA,
11 thereby evaluating the load chronologically rather than merely as an annual peak value.⁵⁵

12 As to the second portion of the Large Load Guideline, ELL evaluated the load under
13 several operating conditions through both its production-cost and transmission-planning
14 analyses. Mr. Datta's AURORA analysis simulates hourly system operations over the ESA
15 term and therefore incorporates both peak and off-peak periods throughout the year. Mr.
16 Kline's transmission planning analysis included full-load conditions, a reduced-load
17 shoulder-season case set at 77% of peak, and sensitivities involving multiple generation
18 outages.⁵⁶

⁵² *Id.* at 7, 42–43; *see also* Exhibit LKB-9.

⁵³ RLS-006 (ELL Response to Staff Data Request 1-108).

⁵⁴ RLS-007 (ELL Response to Staff Data Request 1-66).

⁵⁵ *See* Direct Testimony of Samrat Datta at 12–13.

⁵⁶ *See* Direct Testimony of Daniel Kline at 42–43.

1 ELL also considered seasonal and abnormal system conditions in evaluating the
2 transmission plan. In response to Staff Data Request 1-133, ELL states that its analysis
3 considered fall and spring maintenance periods during which substantial regional
4 generation may be unavailable, north-to-south transfer capability during outages, and
5 extreme-weather conditions such as hurricanes and winter storms.⁵⁷ ELL further explains
6 that its abnormal-event analysis considered the consequences of the loss of a major load
7 center, including the potential for cascading outages and load shed.⁵⁸

8 Accordingly, while the information responsive to this Large Load Guideline is
9 distributed across multiple witnesses, exhibits, and discovery responses, I conclude that
10 ELL has sufficiently presented the proposed load and evaluated its operational
11 characteristics under peak, off-peak, seasonal, and stressed system conditions.

12 **2. LARGE LOAD GUIDELINE #2: RESOURCE ADEQUACY &**
13 **CAPACITY**

14 **Q51. WHAT DOES THE COMMISSION'S SECOND LARGE LOAD GUIDELINE**
15 **ADDRESS?**

16 A. The Commission's second Large Load Guideline addresses whether the utility has
17 demonstrated that sufficient firm, deliverable capacity exists, or will be constructed, to
18 reliably serve the proposed load without impairing system reliability. In particular, the
19 Large Load Guideline requires the utility to demonstrate that:

- 20 • sufficient firm, deliverable capacity exists or will be constructed to serve the
- 21 proposed load without impairing system reliability;
- 22 • the accredited capacity assigned to the proposed resources appropriately reflects
- 23 their expected availability during periods of system peak;

⁵⁷ RLS-005 at 97-98 (ELL Response to Staff Data Request 1-133).

⁵⁸ *Id.* at 4-7 (ELL Responses to Staff Data Requests 1-121 and 1-122).

- any deliverability constraints associated with the proposed resources have been evaluated; and
- the proposed capacity resources are appropriately aligned, both geographically and temporally, with the customer's projected load.

**Q52. PLEASE PROVIDE YOUR ANALYSIS OF ELL'S COMPLIANCE WITH THIS
LARGE LOAD GUIDELINE.**

A. In my opinion, subject to my discussion related to the Load Ramp Period in Large Load Guideline #9, ELL has adequately addressed the requirements of this guideline.

As discussed previously in my testimony, ELL has demonstrated that the projected Evest load will require additional capacity resources and has developed a supply plan intended to satisfy both the Customer's projected contribution to coincident peak together with the applicable MISO PRMR and the Customer's projected maximum demand. The Company's proposed resource portfolio consists of the Proposed Generators, Battery Storage Facilities, the Bayou Cove PCA, and the Waterford 3 uprate, all of which have been identified to serve Evest and all of which have their annual costs assigned to the Customer through the MMC for the term of the ESA.

With respect to resource adequacy, ELL's planning analysis appropriately focuses on the accredited capacity value of the proposed resources rather than simply their installed nameplate capability. Ms. Beauchamp identifies the Customer's projected coincident peak contribution, the applicable planning reserve requirements, and the accredited capacity associated with the proposed resource portfolio. Likewise, the ELL Load and Capability Report produced in response to Staff Data Request 1-1 demonstrates how ELL proposes to satisfy its projected resource adequacy obligations associated with serving Project Evest under the Company's planning assumptions. My conclusion here is limited to the adequacy

1 of ELL's proposed resource portfolio to satisfy the Large Load Guideline's resource
2 adequacy objectives. I separately discuss the timing of those resources and the projected
3 capacity shortfalls during the Customer's ramp period under Large Load Guideline #9
4 relating to Load Ramp Management.

5 ELL also evaluated the deliverability of the proposed resources. As discussed by
6 Mr. Kline, the proposed generation locations and associated transmission facilities were
7 selected through an integrated planning process that considered the ability to interconnect
8 the resources, deliver their accredited capacity to load, and maintain system reliability
9 under the assumed planning scenarios. Likewise, the proposed locations of the generating
10 resources were selected to align the timing and location of the proposed capacity additions
11 with the projected Customer load ramp.

12 Finally, ELL's resource adequacy analysis incorporates [REDACTED]

13 [REDACTED]
14 [REDACTED] For purposes of this Large Load Guideline, I find it
15 sufficient to conclude that ELL appropriately incorporated [REDACTED]
16 [REDACTED]. I separately discuss my review of the operational and
17 reliability implications associated with that proposal under Large Load Guideline #6
18 relating to Operational Control and Curtailment.

19 Accordingly, subject to my observations in Large Load Guideline #9 specifically
20 addressing Load Ramp concerns, I conclude that ELL has demonstrated that firm,
21 deliverable capacity is planned to satisfy the Company's projected resource adequacy
22 obligations associated with serving Project Evest and that the proposed capacity resources

1 have been evaluated with respect to accreditation, deliverability, and their temporal and
2 geographic relationship to the projected load.

3 **3. LARGE LOAD GUIDELINE #3: TRANSMISSION AND**
4 **INTERCONNECTION**

5 **Q53. WHAT DOES THE COMMISSION'S THIRD LARGE LOAD GUIDELINE**
6 **ADDRESS?**

7 A. The Commission's third Large Load Guideline addresses whether the transmission
8 facilities necessary to serve the proposed large load have been properly identified, whether
9 those facilities can be constructed in a timeframe consistent with the customer's projected
10 load ramp, and whether the costs and implementation of those facilities appropriately
11 protect existing customers. Specifically, the Large Load Guideline provides that the utility
12 should demonstrate:

- 13 • all transmission upgrades required to serve the proposed load have been identified,
14 including any facilities that must be newly constructed or whose construction must
15 be accelerated because of the proposed load;
- 16 • network and interconnection costs caused by the load are fully assigned to the load;
- 17 • no material transmission costs are shifted to existing customers that they otherwise
18 would not bear or for which they do not receive commensurate benefits;
- 19 • the proposed transmission upgrade schedule is consistent with the customer's
20 projected load ramp; and
- 21 • the proposed interconnection and queue treatment comply with applicable tariff
22 requirements and do not disadvantage existing customers.

23
24 **Q54. PLEASE PROVIDE YOUR ANALYSIS OF ELL'S COMPLIANCE WITH THIS**
25 **LARGE LOAD GUIDELINE.**

26 A. In my opinion, ELL has substantially addressed the requirements of this Large Load
27 Guideline.

1 As discussed previously in my testimony, ELL identified the transmission facilities
2 it contends are necessary to serve Project Evest, including the Customer-Funded
3 Transmission Interconnection Project, the Customer-Funded Smalling-El Dorado 500-kV
4 Transmission Line, the ELL-Funded WFC-St. Landry 500-kV Transmission Line, and the
5 transmission facilities required to provide construction and commissioning power.
6 Through the testimony of Mr. Kline and the supporting transmission studies, ELL explains
7 the purpose of each project and the role each facility plays in the Company's proposed
8 integrated generation and transmission plan.

9 ELL also demonstrates that the proposed transmission facilities have been planned
10 to correspond with the Customer's projected load ramp. As discussed by Mr. Kline, the
11 transmission planning process was developed in coordination with the proposed generation
12 additions and the Customer's anticipated in-service schedule.⁵⁹ Likewise, Mr. Heytens
13 explains that the integrated planning process was specifically developed to coordinate the
14 timing of resource development, transmission construction, equipment procurement, and
15 project execution with the Customer's requested schedule. Based on my review of the
16 information provided by ELL, I conclude that ELL has adequately demonstrated that the
17 proposed transmission schedule is intended to support the projected load ramp. As
18 discussed later in my testimony under Large Load Guideline #9, my concerns relate not to
19 the proposed construction schedule itself, but rather to whether sufficient capacity
20 resources will be available during portions of the Customer's ramp period.

21 ELL further represents that the proposed transmission facilities have been planned
22 and will be interconnected in accordance with applicable tariff requirements. The

⁵⁹ Direct Testimony of Daniel Kline at 38-39.

1 Company explains that the proposed generation resources at Big Cajun [REDACTED]
2 [REDACTED] and that the remaining interconnection
3 facilities will be developed consistent with the applicable MISO and Entergy transmission
4 planning and interconnection processes.⁶⁰ Based on the information provided by ELL, I
5 have not identified evidence that the proposed interconnection treatment or queue position
6 is inconsistent with the applicable tariff requirements or that existing customers will be
7 disadvantaged through preferential queue treatment.

8 The remaining elements of this Large Load Guideline concern the assignment of
9 transmission and interconnection costs to the Customer and whether material transmission
10 costs are shifted to existing customers without commensurate benefits. Those issues are
11 closely intertwined with ELL's overall economic analysis, the Customer Agreements, and
12 the Company's proposed allocation of costs and risks between Project Evest and existing
13 customers. Because those same issues are addressed more comprehensively under Large
14 Load Guideline #5 relating to Rate Design and Cost Recovery, I defer my discussion of
15 those matters to Sections IV.C.10. and IV.D. that discuss Large Load Guideline #5 Rate
16 Design and Cost Recovery and a Review of ELL's Proposed Total Customer Impact
17 ("TCI").

18 Based on the foregoing, other than cost considerations considered below, I conclude
19 that ELL has identified the transmission facilities necessary to support its proposed service
20 to Project Evest, demonstrated that the proposed transmission schedule has been developed
21 to correspond with the anticipated load ramp, and represented that the proposed

⁶⁰ *Id.* at 40.

interconnection approach is consistent with the applicable transmission planning and tariff requirements.

4. LARGE LOAD GUIDELINE #8: FUEL SUPPLY AND INFRASTRUCTURE RISK

Q55. WHAT DOES THE COMMISSION'S EIGHTH LARGE LOAD GUIDELINE ADDRESS?

A. The Commission's eighth Large Load Guideline addresses whether the utility has adequately considered the fuel supply and related infrastructure necessary to support any new generation proposed to serve the large load. The Large Load Guideline is intended to ensure that the utility has appropriately evaluated the reliability of the proposed fuel supply arrangements and that any risks or costs associated with providing that fuel are not improperly shifted to existing customers. Specifically, the Large Load Guideline provides that the utility should demonstrate:

- the fuel supply arrangements supporting the proposed generation are adequate under both peak and contingency conditions;
- fuel deliverability risks are not shifted to existing customers; and
- any incremental costs associated with fuel deliverability, including pipeline upgrades, firm transportation, storage, or similar infrastructure, have been appropriately identified and addressed.

Q56. PLEASE PROVIDE YOUR ANALYSIS OF ELL'S COMPLIANCE WITH THIS LARGE LOAD GUIDELINE.

A. In my opinion, ELL has adequately addressed the operational and planning requirements of this Large Load Guideline.

ELL's analysis of fuel supply and infrastructure is presented primarily through the testimony of Company witness Michael Goin. Mr. Goin explains that ELL began its evaluation by assessing existing natural gas transportation options available to serve the

1 Proposed Generators. He states that ELL evaluated existing transportation capacity,
2 focused its analysis on high-pressure interstate pipeline facilities, solicited bids from
3 multiple pipeline companies, evaluated different combinations of gas supply and
4 transportation arrangements, considered both greenfield and brownfield pipeline
5 opportunities, and leveraged Entergy's existing natural gas transportation portfolio in an
6 effort to minimize transportation costs while maintaining reliable fuel supply.⁶¹

7 With respect to the specific requirements of this Large Load Guideline, Mr. Goin
8 states that ELL intends to procure new long-term natural gas supply agreements together
9 with firm transportation agreements providing access to multiple upstream natural gas
10 hubs. He further testifies that the proposed transportation portfolio is intended to provide
11 firm transportation sufficient to supply one hundred percent (100%) of the natural gas
12 required for the maximum capability of the seven Proposed Generators. Based on that
13 analysis, Mr. Goin concludes that the proposed fuel supply arrangements will provide
14 adequate fuel under both peak operating conditions and contingency conditions while
15 limiting the risk that fuel deliverability problems are shifted to ELL's existing customers.⁶²

16 Mr. Goin next discusses the specific infrastructure available to support the proposed
17 generation resources. For the Richland facilities, he identifies five high-capacity interstate
18 natural gas pipelines located within approximately ten miles of the proposed generation
19 site, states that those pipelines presently provide approximately nine billion cubic feet
20 ("Bcf") per day of transportation capability and explains that additional expansion
21 opportunities could increase that capacity to more than ten Bcf per day. He further explains

⁶¹ Direct Testimony of Michael Goin at 7-8.

⁶² *Id.* at 8.

1 that ELL is actively negotiating with multiple transportation providers and multiple natural
2 gas suppliers to obtain firm transportation and long-term gas supply arrangements for the
3 Richland facilities.⁶³

4 Mr. Goin likewise discusses the proposed fuel infrastructure serving the Pointe
5 Coupee facilities. He explains that existing transportation infrastructure is insufficient to
6 serve the proposed generators and that additional pipeline facilities will therefore be
7 required. He states that ELL evaluated both greenfield and brownfield pipeline
8 alternatives, received proposals from multiple pipeline companies, and expects the
9 proposed transportation arrangements to provide access to multiple upstream supply
10 basins, thereby increasing both supply competition and system reliability.⁶⁴

11 The remaining portions of this Large Load Guideline concern the allocation of fuel
12 transportation costs and the extent to which those costs or associated risks may ultimately
13 be borne by existing customers. ELL addresses those issues through the Customer
14 Agreements and its proposed ratemaking treatment. Because those issues are more
15 appropriately considered together with ELL's overall cost recovery proposal, I defer my
16 discussion of these matters to Sections IV.C.10. and IV.D. that discuss Large Load
17 Guideline #5, Rate Design and Cost Recovery and a Review of ELL's Proposed TCI.

18 Accordingly, other than cost considerations discussed below, I conclude that ELL
19 has demonstrated that it evaluated the fuel supply and infrastructure necessary to support
20 the Proposed Generators and that the proposed fuel supply arrangements are intended to
21 provide reliable natural gas service under both peak and contingency conditions.

⁶³ *Id.* at 9-11.

⁶⁴ *Id.* at 11-12.

5. LARGE LOAD GUIDELINE #11: ENVIRONMENTAL & LOCAL IMPACTS

Q57. WHAT DOES THE COMMISSION'S ELEVENTH LARGE LOAD GUIDELINE ADDRESS?

A. The Commission's eleventh Large Load Guideline addresses whether the utility has adequately identified the environmental and local system impacts associated with the utility serving the proposed load and, to the extent mitigation is required, whether appropriate mitigation measures have been developed and the associated compliance costs have been appropriately assigned. Specifically, the Large Load Guideline provides that the utility should demonstrate:

- the environmental and local system impacts associated with serving the proposed load have been identified;
- appropriate mitigation measures have been developed where necessary; and
- the costs associated with those mitigation measures have been appropriately assigned.

Q58. PLEASE PROVIDE YOUR ANALYSIS OF ELL'S COMPLIANCE WITH THIS LARGE LOAD GUIDELINE.

A. In my opinion, ELL has adequately addressed the requirements of this Large Load Guideline.

As an initial matter, I believe it is important to recognize the scope of this Guideline. The Large Load Guideline addresses the environmental and local system impacts associated with the utility serving the proposed load and not any environmental compliance of the Customer. Accordingly, my review is limited to the environmental impacts associated with ELL's proposed generation and transmission facilities and does not extend to the broader environmental impacts associated with the Customer's industrial operations.

1 ELL addresses the environmental impacts associated with the Proposed Generators
2 through the testimony of Mr. Halland. Mr. Halland identifies the principal environmental
3 permitting authorities having jurisdiction over the Proposed Generators, including the
4 Louisiana Department of Environmental Quality (“LDEQ”), the Louisiana Department of
5 Conservation and Energy (“LDCE”), the United States Environmental Protection Agency
6 (“EPA”), and the United States Army Corps of Engineers (“USACE”). He further
7 identifies the principal federal and state environmental statutes governing the project,
8 including the Clean Air Act, the Clean Water Act, the Resource Conservation and
9 Recovery Act, and the Louisiana Environmental Quality Act, and explains the respective
10 responsibilities of those agencies in the permitting process.⁶⁵

11 Mr. Halland concludes that ELL will manage the Proposed Generators in
12 accordance with all applicable federal, state, and local environmental requirements, that
13 the Proposed Generators have been designed to comply with current environmental
14 regulations while accommodating anticipated future regulatory requirements, and that ELL
15 has developed a permitting plan incorporating conservative review periods for each
16 required permit. He further concludes that the construction and operation of the Proposed
17 Generators will not adversely impact recreational or park areas, historical or aesthetic
18 values, or the environmental integrity of the surrounding areas.⁶⁶

19 With respect to air quality, Mr. Halland identifies the specific permits required for
20 construction and operation of the Proposed Generators, including Prevention of Significant
21 Deterioration (“PSD”) Air Permits, Title V Operating Permits, and Acid Rain Permits. He

⁶⁵ Direct Testimony of Jeremy Halland at 3-4.

⁶⁶ *Id.* at 4.

1 further explains that the Proposed Generators have been designed to satisfy Best Available
2 Control Technology (“BACT”) requirements through the use of Selective Catalytic
3 Reduction (“SCR”), dry low-NOx combustors, and oxidation catalysts.⁶⁷

4 Mr. Halland likewise addresses water quality permitting. He explains that any
5 required Louisiana Pollutant Discharge Elimination System (“LPDES”) permits will be
6 obtained prior to operation of the facilities and discusses the permitting requirements
7 applicable to wastewater and stormwater discharges under both federal and state law.⁶⁸

8 Finally, ELL supplemented Mr. Halland’s testimony through Staff Data Request
9 1-155 by providing estimated permitting schedules for each major environmental permit
10 together with comparable permitting timelines from recent projects and identifying the
11 principal permitting risks that could affect the project schedule.⁶⁹

12 The costs for environmental compliance will be included in the revenue
13 requirements of the generation and transmission projects to which they are applicable. The
14 satisfaction of the Large Load Guideline related to cost recovery is discussed below.
15 Allocation of costs are discussed below when discussing Large Load Guideline #5 Rate
16 Design and Cost Recovery.

17 Accordingly, I conclude that ELL has identified the environmental impacts
18 associated with the proposed utility facilities, described the anticipated mitigation and
19 permitting requirements, and incorporated those requirements into its project development
20 and permitting schedule. Therefore, other than the cost recovery implications addressed in

⁶⁷ *Id.* at 5-6.

⁶⁸ *Id.* at 8-9.

⁶⁹ RLS-008 (ELL Response to Staff Data Request 1-155).

1 my below consideration of Large Load Guideline #5 Rate Design and Cost Recovery, I
2 conclude that ELL has addressed the requirements of this Large Load Guideline.

3 **6. LARGE LOAD GUIDELINE #9: LOAD RAMP MANAGEMENT**

4 **Q59. WHAT DOES THE COMMISSION'S NINTH LARGE LOAD GUIDELINE**
5 **ADDRESS?**

6 A. The Commission's ninth Large Load Guideline addresses whether the utility has
7 appropriately coordinated the customer's anticipated load ramp with the availability of the
8 generation and transmission resources necessary to reliably serve that load. The Large
9 Load Guideline recognizes that, for a project of this magnitude, it is not sufficient to
10 demonstrate only that adequate resources will ultimately be available once the client has
11 ramped to its full load. Rather, the utility should also demonstrate that the proposed load
12 additions will occur in a manner that remains consistent with the availability of those
13 resources throughout the customer's ramp to full operation. Specifically, the Large Load
14 Guideline provides that the utility should demonstrate:

- 15 • the customer's projected load ramp is coordinated with the availability of the
- 16 proposed generation and transmission resources;
- 17 • the load ramp incorporates enforceable milestones; and
- 18 • the proposed ramp schedule does not result in interim degradation of system
- 19 reliability.
- 20

21 **Q60. DOES YOUR REVIEW OF THIS LARGE LOAD GUIDELINE INVOLVE MORE**
22 **THAN ONE ISSUE?**

23 A. Yes. In my opinion, this Large Load Guideline presents two related, but distinct, issues.

24 The first concerns system reliability during the Customer's ramp period.
25 Specifically, whether ELL has demonstrated that the proposed load ramp can be

1 accommodated without degrading system reliability while the proposed generation, battery
2 storage, and transmission facilities are progressively placed into service.

3 The second issue concerns the economic consequences associated with the
4 proposed ramp. The Company's planning analyses continue to reflect projected resource
5 adequacy shortfalls during portions of the ramp period, and ELL's own economic analyses
6 assign a cost to those projected deficiencies. Accordingly, in addition to evaluating
7 whether ELL has reasonably addressed the reliability implications associated with the
8 proposed ramp, I also evaluate the extent to which ELL has identified and appropriately
9 allocated the economic consequences associated with those projected shortfalls.

10 For clarity, I address those two issues separately.

11 **Q61. PLEASE PROVIDE YOUR ANALYSIS OF THE FIRST ISSUE - THE**
12 **RELIABILITY IMPLICATIONS ASSOCIATED WITH THE PROPOSED LOAD**
13 **RAMP.**

14 A. In my opinion, ELL has undertaken a reasonable analytical process to evaluate the
15 reliability implications associated with the proposed load ramp. However, based on the
16 information received to date, I cannot conclude that ELL has adequately addressed this
17 issue.

18 As discussed previously in my testimony, the Company's Load and Capability
19 Report ("LCR") produced in response to Staff Data Request 1-1 continues to reflect
20 projected resource adequacy deficiencies during portions of the Customer's ramp period.

21 Those projected deficiencies exist [REDACTED]

22 [REDACTED]
23 [REDACTED] Likewise, ELL's own economic analysis

1 recognizes the potential for interim capacity deficiencies by assigning an economic cost to
2 any net capacity shortfalls over the term of the ESA through the TCI analysis. Mr. Datta
3 explains that any net change in ELL's capacity position associated with serving Project
4 Evest is quantified in the economic analysis using the levelized cost of a long-term
5 combustion turbine resource.⁷⁰

6 ELL's principal response to those projected L&C capacity deficiencies from a
7 reliability perspective is not that they disappear, but rather that the Customer's firm and
8 non-firm load obligations were intentionally developed to maintain system reliability
9 during the Commissioning Period. Mr. Datta testifies that [REDACTED]

10 [REDACTED]
11 [REDACTED]
12 [REDACTED]
13 [REDACTED]
14 [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 [REDACTED]

18 ELL further explains this analytical approach in response to Staff Data Request 1-
19 108. There, ELL states that the amount of firm and non-firm load permitted during the
20 Ramp Schedule was negotiated "with the aim of maintaining the same level of reliability
21 and supply adequacy as would have existed for the ELL system if the Customer load and

⁷⁰ Direct Testimony of Samrat Datta at 21-22.

⁷¹ *Id.* at 21-23.

1 resources proposed in connection with serving the Customer had not been connected to the
2 system.” [REDACTED]

3 [REDACTED]

4 [REDACTED]

5 [REDACTED].⁷²

6 I believe the methodology described by ELL represents a reasonable analytical
7 approach to managing the reliability challenges associated with the proposed load ramp.
8 However, Staff was not provided the proprietary reliability models, the successive
9 modeling iterations performed by ELL, or the analytical basis supporting the final
10 determination of the firm and non-firm load schedules ultimately incorporated into
11 Appendix C of the ESA. Accordingly, while I understand the methodology employed by
12 ELL, I cannot independently validate the assumptions embedded within those models or
13 determine whether the resulting firm and non-firm load schedules represent a reasonable
14 solution to the reliability concerns presented during the Commissioning Period.

15 The Company’s analysis also necessarily depends on numerous planning
16 assumptions regarding future events, including the timely completion of the proposed
17 generation resources, battery storage facilities, and transmission projects. Those
18 assumptions are inherently subject to change over the course of the Customer’s ramp
19 period. For example, after the filing of this Application, the Iberville Parish Council
20 adopted a two-year moratorium on industrial battery energy storage system development
21 following public concerns regarding battery storage facilities. While I express no opinion
22 regarding the merits of that local action or its applicability to ELL’s proposed Battery

⁷² RLS-006 (ELL Response to Data Request 1-108).

1 Storage Facilities, it illustrates that permitting, regulatory, construction, and other external
2 developments can materially affect the timing or availability of planned resources on which
3 reliability analyses are based. Although Section 4.B. of Rider 1 [REDACTED]
4 [REDACTED], I have been unable to identify a corresponding
5 mechanism addressing the circumstance where a planned resource is ultimately cancelled
6 or permanently removed from the Company's supply plan rather than merely delayed.
7 Intuitively a cancellation would just indefinitely suspend the capacity being added until
8 another identified resource was put into service, but the Customer Agreements are less than
9 clear on that issue.

10 Accordingly, while I conclude that ELL has undertaken a reasonable analytical
11 process to evaluate the reliability implications associated with the proposed load ramp, I
12 do not believe a potential Commission's certification should be interpreted as an
13 endorsement of every future decision necessary to implement that ramp. The analyses
14 presented in this proceeding necessarily depend on assumptions regarding future resource
15 availability, construction schedules, transmission facilities, and system conditions that may
16 ultimately differ from those assumed in ELL's studies.

17 For that reason, if the Commission grants the requested certifications, I recommend
18 that the certifications be limited to the facilities requested in this proceeding and not be
19 construed as approval of ELL's future operational decisions regarding implementation of
20 the Customer Agreements or the Customer's Ramp Schedule. ELL should retain full
21 responsibility for prudently administering those agreements and modifying the Customer's
22 ramp schedule as changing resource availability, construction progress, system conditions,
23 and reliability considerations may require.

Q62. PLEASE PROVIDE YOUR ANALYSIS OF THE SECOND ISSUE -ECONOMIC IMPLICATIONS ASSOCIATED WITH THE PROPOSED LOAD RAMP.

A. The proposed load ramp presents not only a reliability issue, but also an economic one.

As discussed above, the Company's Load and Capability Report continues to project resource adequacy deficiencies during portions of the Customer's ramp period. ELL recognizes that those projected deficiencies may require the acquisition of incremental capacity resources during the Commissioning Period and has incorporated the associated costs into its economic analyses.

Specifically, Mr. Datta explains that ELL quantified the economic impact of projected capacity shortfalls by assigning a cost to those deficiencies using the levelized cost of a long-term combustion turbine resource. Those projected capacity shortfall costs are incorporated into the Company's TCI analysis contained in Exhibit SD-2 and therefore form part of the overall economic evaluation of Project Evest.⁷³

ELL's economic analysis also recognizes that the Commissioning Period produces incremental revenues in addition to incremental costs. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]⁷⁴

⁷³ Direct Testimony of Samrat Datta at 21; *see also* Exhibit SD-2.

⁷⁴ Direct Testimony of Ryan Jones at 40; *see also* Exhibit SD-2.

1 Accordingly, I recognize that ELL's economic evaluation of the Commissioning
2 Period considers both the projected costs associated with interim capacity deficiencies and
3 the projected revenues associated with serving the Customer during that period. ELL
4 ultimately concludes that the long-term economic benefits associated with Project Evest
5 substantially outweigh those interim costs. I do not disagree that the overall project may
6 provide net economic benefits over the term of the Customer Agreements and I address
7 this issue in Section IV.D.

8 Nevertheless, I have concerns that the net impact of the ramp period shortages could
9 cause significant increases in capacity costs to be absorbed by customers in rates in the
10 near term at a time when rates are already under tremendous upward pressure due to other
11 factors. Additionally, the Commission and ELL are currently in disagreement involving
12 the ramp period shortages of Laidley in LPSC Docket No. U-37801.⁷⁵

13 According to the foregoing, I conclude that ELL has not adequately demonstrated
14 this issue and I recommend that the Commission condition any potential certification on
15 ELL developing a ratemaking mechanism that better aligns the net costs associated with
16 these ramp capacity shortages with the benefits projected to be received once all the
17 generation is in service.

⁷⁵ LPSC Docket No. U-37801 (*In re: Application for approval to acquire Cottonwood Generation Facility, including cost recovery*).

1 **7. LARGE LOAD GUIDELINE #6: OPERATIONAL CONTROL AND**
2 **CURTAILMENT**

3 **Q63. WHAT DOES THE COMMISSION'S SIXTH LARGE LOAD GUIDELINE**
4 **ADDRESS?**

5 A. The Commission's sixth Large Load Guideline addresses whether the utility has retained
6 sufficient operational control over the proposed large load to maintain the reliability of the
7 electric system under both normal and emergency operating conditions. The Large Load
8 Guideline recognizes that, for a load of the magnitude proposed by Project Evest, the utility
9 must possess sufficient contractual and operational authority to reduce or interrupt service
10 whenever necessary to preserve system reliability. Specifically, the Large Load Guideline
11 provides that the utility should demonstrate:

- 12 • the utility retains sufficient operational control, including the right to curtail service
- 13 when necessary to maintain system reliability;
- 14 • any curtailment rights are clearly defined and contractually enforceable;
- 15 • the priority of service during emergency conditions is clearly established; and
- 16 • any compensation associated with curtailment is transparent and established in
- 17 advance.

18
19 **Q64. PLEASE PROVIDE YOUR ANALYSIS OF ELL'S COMPLIANCE WITH THIS**
20 **LARGE LOAD GUIDELINE.**

21 A. In my opinion, ELL has demonstrated that it has given appropriate consideration to the
22 issues addressed by this Large Load Guideline. However, I conclude that ELL has not
23 adequately addressed all aspects of the Large Load Guideline based on the present
24 information provided by ELL.

25 During the Commissioning Period, ELL has developed a contractual framework
26 intended to provide operational control over the Customer's non-firm load. As discussed
27 previously, ELL proposes to utilize the firm and non-firm service obligations established

1 in Appendix C to the Customer Agreements [REDACTED]

2 [REDACTED]. Through the
3 testimony of Mr. Datta and ELL's response to Staff Data Request 1-108, ELL explains that
4 these provisions were specifically developed to provide ELL with the operational
5 flexibility necessary to manage reliability during the Customer's load ramp.⁷⁶ Subject to
6 the concerns and recommendations discussed in my review of Large Load Guideline #9
7 regarding the implementation and ongoing management of Appendix C, I conclude that
8 ELL has developed a reasonable contractual framework for operational control during the
9 Commissioning Period.

10 Following the Commissioning Period, however, the Customer's service is expected
11 to become fully firm. At that point, the principal issue is no longer the contractual
12 distinction between firm and non-firm service, but rather ELL's ability to reliably integrate
13 a single [REDACTED] MW customer into its emergency operating procedures while continuing to
14 provide firm service consistent with the Company's obligations to all customers.

15 The Commission is presented with two equally important considerations. First, if
16 the Customer is paying for firm service, it should receive the benefits and protections
17 associated with firm service. Second, because the Customer will be interconnected to
18 ELL's system as a firm customer, it should be subject to emergency operating procedures
19 in a fair, reasonable, and non-discriminatory manner consistent with other firm customers.
20 The objective should neither be to afford Project Evest preferential treatment because of
21 its size nor to subject it to more restrictive operational requirements than other firm

⁷⁶ Direct Testimony of Samrat Datta at 22-23; *see also* RLS-006 (ELL Response to Staff Data Request 1-108.)

1 customers. Rather, the objective should be to ensure that ELL has established clear
2 operational protocols that appropriately balance those considerations while maintaining the
3 reliability of the electric system.

4 On that issue, however, the present information provided by ELL is incomplete.
5 While ELL has acknowledged that these operational procedures are still under
6 development, the information provided by ELL does not presently demonstrate how that
7 balance will ultimately be achieved. Mr. Kline acknowledges that ELL is continuing to
8 develop the operational protocols governing how hyperscale customers will be
9 incorporated into ELL's emergency load shed procedures.⁷⁷ Likewise, in response to Staff
10 Data Request 1-132, ELL states that it has not yet determined whether Project Evest can
11 be curtailed in discrete increments, the size of those increments, or the operational
12 procedures that will govern such curtailments. ELL further states that those determinations
13 will be made through its forward-looking operational planning process closer to the time
14 the Customer enters service.⁷⁸

15 I do not view ELL's continued development of these operational procedures as
16 unreasonable. Given the anticipated timeline for Project Evest and the evolution of
17 operating conditions over time, it is reasonable that certain operational details will be
18 finalized closer to the commencement of service. However, because those procedures have
19 not yet been developed, I cannot conclude that ELL has adequately addressed this portion
20 of the Large Load Guideline. The ability to reliably integrate a single [REDACTED] MW firm
21 customer into ELL's emergency operating procedures while preserving both system

⁷⁷ Direct Testimony of Daniel Kline at 51.

⁷⁸ RLS-005 at 95-96 (Public Version) (ELL Response to Staff Data Request 1-132).

1 reliability and the Customer's contractual rights as a firm service customer is a significant
2 operational issue that should be resolved before full firm service begins.

3 Accordingly, if the Commission grants the requested certifications, I recommend
4 that, as a condition of those certifications, ELL be required to develop and submit,
5 sufficiently in advance of the commencement of full firm service, a detailed operational
6 control and emergency load shed plan for Commission review and approval. At a
7 minimum, that plan should identify how Project Evest will be incorporated into ELL's
8 emergency operating procedures, whether and how the Customer's load can be curtailed in
9 discrete increments, the operational sequence for implementing such curtailments, the
10 communications protocols to be utilized, and any physical or contractual limitations
11 affecting ELL's operational control of the Customer's load. The plan should also
12 demonstrate how those procedures will be implemented in a manner that preserves the
13 Customer's rights as a firm service customer while ensuring that emergency operating
14 measures are applied in a fair, reasonable, and non-discriminatory manner consistent with
15 other customers.

16 **8. LARGE LOAD GUIDELINE #7: ANCILLARY SERVICES AND**
17 **POWER QUALITY**

18 **Q65. WHAT IS THE PURPOSE OF THE SEVENTH LARGE LOAD GUIDELINE**
19 **ADDRESSING ANCILLARY SERVICES AND POWER QUALITY?**

20 A. Large Load Guideline #7 is intended to ensure that the proposed customer can be integrated
21 into the utility's electrical system without adversely affecting the reliability or quality of
22 electric service provided to other customers. Unlike the previous Large Load Guidelines,
23 which primarily address the adequacy of generation and transmission resources necessary
24 to serve the Customer's load, this Large Load Guideline focuses on the electrical

1 characteristics of the Customer's facilities and their interaction with ELL's transmission
2 and distribution systems.

3 Specifically, the Large Load Guideline contemplates whether the utility has
4 adequately evaluated issues such as voltage stability, power quality, harmonic distortion,
5 flicker, reactive power requirements, frequency response, and other operational
6 characteristics that could affect the utility's system or neighboring customers. It also
7 considers whether appropriate technical standards, monitoring requirements, and
8 mitigation measures have been identified to address any adverse impacts associated with
9 connecting and operating the proposed facilities.

10 For a project of this magnitude, these considerations are particularly important
11 because hyperscale data centers can exhibit operating characteristics that differ
12 significantly from traditional industrial loads. Accordingly, the Commission should be
13 satisfied that ELL has appropriately evaluated these issues, identified any potential impacts
14 to the electric system, and established reasonable measures to mitigate those impacts before
15 the Customer commences operation.

16 **Q66. WHAT IS YOUR ANALYSIS OF ELL'S COMPLIANCE WITH LARGE LOAD**
17 **GUIDELINE #7?**

18 A. In my opinion, ELL has addressed Large Load Guideline #7.

19 Mr. Kline explains that the new combined-cycle generating units will provide more
20 than real-power capability. They will also add dynamic reactive-power capability,
21 synchronous inertial response, and short-circuit capability to the system. He explains that
22 inadequate reactive-power capability can impair voltage regulation and contribute to
23 voltage dips and sags, while dynamic reactive power supports voltage recovery. He further

1 states that the synchronous inertial response and short-circuit capability provided by the
2 new units may become increasingly valuable ancillary-service attributes as renewable and
3 inverter-based resources increase within MISO.⁷⁹

4 ELL also performed analyses directed specifically at voltage and system-stability
5 concerns. Mr. Kline testifies that ELL performed steady-state analyses for each of the three
6 studied scenarios while monitoring voltage and performed transient-stability analysis using
7 the proposed transmission upgrades as the basis for a robustness test. He states that the
8 transient-stability analysis identified no additional constraints.⁸⁰ Mr. Kline further explains
9 that the voltage constraints identified in the studied scenarios are addressed through the
10 proposed transmission upgrades.⁸¹

11 ELL's analysis also addresses the possibility that more detailed information
12 regarding the Customer's equipment and operating characteristics may reveal issues that
13 cannot presently be identified. Mr. Kline testifies that ELL continues to work with the
14 Customer as detailed facility design is completed and will continue studying how Project
15 Evest affects the system as additional information concerning Project Evest and Project
16 Laidley becomes available. He further explains that the Customer must comply with
17 applicable IEEE standards governing harmonics and flicker and must address issues caused
18 by its facilities.⁸²

⁷⁹ Direct Testimony of Daniel Kline at 41.

⁸⁰ *Id.* at 47.

⁸¹ *Id.* at 47-48.

⁸² *Id.* at 48-49.

1 ELL has also provided for monitoring after the Customer begins operation. Mr.
2 Kline testifies that ELL will install power-quality meters and phasor measurement units at
3 each of the Customer's load-serving substations to provide visibility into any power-
4 quality issues that arise.⁸³

5 Mr. Kline's testimony appropriately recognizes that some dynamic-system
6 interactions cannot be conclusively identified at this stage. In addressing torsional stress
7 and other risks associated with the dynamic behavior of the Customer's facilities, he
8 explains that ELL evaluated those risks as fully as reasonably possible with the information
9 currently available. He further explains that torsional-stress issues may be nearly
10 impossible to detect in advance because of the detailed information necessary to accurately
11 model the effects of system changes and that such issues are generally identified through
12 system operation and then corrected.⁸⁴

13 I find this distinction important. The present inability to identify every potential
14 dynamic interaction does not, by itself, establish that ELL's analysis is incomplete. Rather,
15 the relevant question is whether ELL performed the analyses reasonably available at this
16 stage, established a process to obtain and evaluate additional information, and provided
17 enforceable means to monitor and mitigate problems if they occur. Mr. Kline expressly
18 testifies that his team considered all relevant information reasonably expected to be
19 available at this stage of an industrial-development project and performed comprehensive
20 and methodical analyses using conservative assumptions where appropriate. Those
21 analyses included steady-state, stability, and short-circuit studies intended to identify the

⁸³ *Id.* at 49.

⁸⁴ *Id.* at 49-50.

1 transmission and generation upgrades needed to accommodate the Customer's load while
2 complying with applicable NERC Reliability Standards and ELL's local transmission-
3 planning guidelines and criteria.⁸⁵

4 The ESA supplements that engineering analysis with specific performance
5 requirements and mitigation obligations. Article V requires [REDACTED]

6 [REDACTED]

7 [REDACTED]

8 [REDACTED]

9 [REDACTED]

10 [REDACTED]⁸⁶

11 Article V separately addresses [REDACTED] [REDACTED]

12 [REDACTED]

13 [REDACTED]

14 [REDACTED]

15 [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 [REDACTED]

19 The ESA also establishes responsibility and deadlines for mitigation. [REDACTED]

20 [REDACTED]

⁸⁵ *Id.* at 52.

⁸⁶ *See* Exhibit LKB-2, ESA, Article V, p. 4.

⁸⁷ *See* Exhibit LKB-2, ESA, Article V, p. 5.

1 [REDACTED]

2 [REDACTED]

3 [REDACTED].⁸⁸

4 Mr. Kline confirms the relationship between these contractual provisions and
5 ELL's ongoing power-quality obligations. He testifies that ELL is prepared to report
6 annually to the Commission regarding power-quality impacts and proposes continuing
7 those reports until three consecutive years of full-facility operation have occurred without
8 a material power-quality issue. He further states that, when a material power-quality issue
9 is caused solely by operation of the Customer's facilities, the Customer will pay the cost
10 of the upgrades necessary to resolve it. Mr. Kline explains that ELL negotiated the
11 additional ESA provisions addressing power quality, harmonics, flicker, and system
12 oscillations in direct response to concerns raised in Docket U-37425.⁸⁹

13 Mr. Jones likewise identifies the power-quality requirements as one of the
14 provisions intended to protect ELL's other customers. He states that the Customer agreed
15 to pay for all additional equipment required to correct power-quality issues caused by the
16 Customer's load.⁹⁰

17 Based on the information provided by ELL, I conclude that ELL has addressed
18 Large Load Guideline #7. ELL has identified the ancillary-service and power-quality
19 attributes of the proposed resources, performed the voltage, stability, and short-circuit
20 analyses reasonably available at this stage, and established a process for continued study

⁸⁸ See Exhibit LKB-2, ESA, Article V, pp. 5-6.

⁸⁹ Direct Testimony of Daniel Kline at 52-53.

⁹⁰ Direct Testimony of Ryan Jones at 64.

1 and operational monitoring as more detailed information becomes available. While ELL
2 cannot predict every issue that will arise, ELL has performed the analyses reasonably
3 available at this stage. Just as importantly, the ESA establishes measurable standards,
4 correction obligations, implementation deadlines, and responsibility for the costs of
5 mitigating power-quality problems attributable to the Customer. In my opinion, that is a
6 reasonable framework for addressing both the issues that can be evaluated before operation
7 and those that can only be identified after the Customer's actual equipment is further
8 designed, installed and energized.

9 **9. LARGE LOAD GUIDELINE #10: MARKET AND PLANNING**
10 **IMPACTS**

11 **Q67. WHAT DOES THE COMMISSION'S TENTH LARGE LOAD GUIDELINE**
12 **ADDRESS?**

13 A. Large Load Guideline #10 is intended to ensure that the proposed large load is
14 appropriately incorporated into the utility's resource planning and market operations and
15 that the addition of the load does not create unreasonable impacts on either the utility's
16 planning processes or wholesale market participation. Unlike the previous Large Load
17 Guidelines, which focus primarily on the physical ability to serve the Customer's load and
18 maintain reliable electric service, this Large Load Guideline considers the broader planning
19 and market implications associated with integrating a customer of this magnitude into the
20 utility's electric system.

21 Specifically, the Large Load Guideline contemplates whether the utility has
22 reasonably evaluated the effects of the proposed load on resource adequacy planning,
23 transmission planning, reserve requirements, wholesale market participation, capacity
24 obligations, dispatch decisions, ancillary service requirements, and other planning

1 assumptions that may affect both the utility and its existing customers. It also considers
2 whether the utility has identified any significant operational or market impacts associated
3 with serving the proposed load and established reasonable plans to address those impacts.

4 For a project of this magnitude, these considerations are particularly important
5 because the Customer's projected demand represents a significant addition to ELL's
6 existing system load and will necessarily influence future resource planning, transmission
7 planning, and participation in the MISO markets. Accordingly, the Commission should be
8 satisfied that ELL has reasonably evaluated those market and planning impacts and
9 incorporated them into its planning processes in a manner that maintains reliable service
10 while appropriately protecting existing customers.

11 **Q68. HAVE YOU REVIEWED ELL'S ANALYSIS OF THE MARKET AND PLANNING**
12 **IMPACTS ASSOCIATED WITH PROJECT EVEST?**

13 A. Yes. I have reviewed the information provided by ELL addressing the anticipated impacts
14 of Project Evest on ELL's generation portfolio, wholesale market operations, transmission
15 system, and long-term resource planning. Those portions of the information provided by
16 ELL include, in particular, the Direct Testimony of Company witnesses Samrat Datta,
17 Laura K. Beauchamp, Ryan D. Jones, and Daniel Kline.

18 **Q69. WHAT ARE YOUR CONCLUSIONS?**

19 A. Based on my review of the information provided by ELL, I conclude that ELL has
20 adequately addressed this Large Load Guideline.

21 The information provided by ELL demonstrates that ELL evaluated the expected
22 market and planning impacts of Project Evest using multiple analytical approaches rather
23 than relying on a single metric. Those analyses include an assessment of wholesale

1 production costs, capacity impacts, transmission impacts, customer revenues, resource
2 planning considerations, and the interaction of Project Evest with ELL's broader resource
3 portfolio. While I may disagree with certain assumptions utilized in those analyses, I find
4 that ELL has reasonably identified and evaluated the principal market and planning issues
5 associated with serving Project Evest.

6 **Q70. PLEASE EXPLAIN THE BASIS FOR YOUR CONCLUSION.**

7 A. Mr. Datta explains that his economic assessment was designed to evaluate the overall
8 impact of Project Evest on ELL's existing customers by comparing a Base Case, in which
9 ELL does not serve Project Evest or incur the costs or receive the benefits associated with
10 the proposed resources, with a Change Case that incorporates the Customer's load, the
11 Proposed Resources, the Proposed Transmission Projects, Customer revenues, and changes
12 in wholesale variable supply costs. Mr. Datta explains that this comparison produces the
13 TCI, which is intended to measure the overall costs and benefits to ELL's other customers
14 over the Original Term of the Electric Service Agreement.⁹¹

15 Mr. Datta further explains that the economic assessment does not simply compare
16 revenue requirements. Rather, it also incorporates a production-cost analysis intended to
17 quantify the effect that serving Project Evest will have on ELL's wholesale variable supply
18 costs. According to Mr. Datta, this production-cost analysis evaluates the combined effects
19 of the additional Customer load, the Proposed Resources, and the Proposed Transmission
20 Projects over the full twenty-year Original Term of the ESA and incorporates those results
21 into the overall TCI calculation.⁹²

⁹¹ Direct Testimony of Samrat Datta at 8–9.

⁹² *Id.* at 11.

1 Mr. Datta describes in detail the production-cost methodology used in that analysis.
2 Specifically, he explains that ELL utilized the AURORA production-cost model to
3 simulate security-constrained unit commitment and economic dispatch in a Day-2 energy
4 market such as MISO. He further explains that the model incorporates forecasted hourly
5 load, reserve-margin requirements, transmission-transfer limits, individual generating-
6 resource operating characteristics, projected unit deactivation dates, future resource
7 additions, natural-gas price forecasts, fuel-transportation costs, emissions costs, and
8 assumptions derived from ELL's 2026 Business Plan. He also explains that the Change
9 Case specifically includes the Project Evest hourly load forecast as it ramps, the Proposed
10 Generators, the Battery Storage Facilities, and changes in zonal transmission-transfer
11 capability and Voltage and Local Reliability commitment levels resulting from the
12 Proposed Transmission Projects.⁹³

13 Mr. Datta also explains that the economic assessment separately evaluates the
14 impacts of Project Evest on fuel and capacity costs. With respect to fuel costs, the
15 AURORA production-cost analysis first quantifies the change in ELL's Variable Supply
16 Cost resulting from the addition of Project Evest's load together with the proposed
17 resources. That analysis therefore captures the increased system production costs
18 associated with serving the additional load, including the effect of dispatching higher-cost
19 resources as additional load is added to the system. Mr. Datta then incorporates those
20 production-cost results into his Exhibit SD-2, which separately recognizes the Customer's
21 projected fuel-related payments through the Fuel Adjustment Clause. As explained in the
22 Company's response to Staff Data Request 1-10, the average fuel cost charged to the firm

⁹³ *Id.* at 12–14.

1 portion of the Customer's load is derived from the difference between the normalized
2 Variable Supply Cost in the Change Case and the Base Case, while the non-firm portion
3 of the Customer's load is assumed to pay the ELL Load Zone Locational Marginal Price
4 ("LMP") in the Change Case. Thus, the analysis recognizes both the increased fuel costs
5 imposed on the system by serving Project Evest and the corresponding fuel-related
6 contributions made by the Customer toward those increased costs. Mr. Datta further
7 explains that the analysis also recognizes increases in Project Laidley's fuel-related
8 payments resulting from Project Evest because those additional payments likewise reduce
9 the fuel-cost burden that would otherwise be borne by ELL's remaining customers.⁹⁴

10 With respect to capacity impacts, Mr. Datta explains that the analysis accounts on
11 the supply side for the change in ELL's capacity position resulting from the Proposed
12 Resources and their accredited capacity. On the demand side, the analysis accounts for the
13 PRMR associated with Project Evest's load. He further explains that any resulting net
14 change in ELL's capacity position is quantified using the levelized cost of a combustion
15 turbine as the cost of a long-term capacity resource.⁹⁵

16 Mr. Datta also identifies certain market and system benefits that were intentionally
17 excluded from the quantitative economic assessment. He explains that potential pipeline-
18 transportation synergies associated with the three Proposed Generators planned for south
19 Louisiana and another future CCCT included in ELL's 2026 Business Plan were excluded
20 from the analysis. He likewise explains that, apart from changes in variable supply costs
21 resulting from improvements in zonal transfer capability, the reliability and resilience

⁹⁴ *Id.* at 12-14, 17-18; *see also* RLS-009 (ELL Responses to Staff Data Request 1-10 and 1-14).

⁹⁵ Direct Testimony of Samrat Datta at 20-21.

1 benefits associated with the Proposed Transmission Projects, including the West Fork
2 Creek–St. Landry 500-kV Transmission Line and St. Landry 500-kV Switching Station,
3 were not quantified in the economic assessment.⁹⁶

4 Ms. Beauchamp explains that the Proposed Generators are not intended to operate
5 exclusively for Project Evest but instead are proposed as system resources that will become
6 part of ELL’s overall generation-resource portfolio and will be committed and dispatched
7 in the normal order, consistent with security-constrained economic unit commitment and
8 dispatch, to serve the needs of all ELL customers. She similarly explains that the Battery
9 Storage Facilities are being acquired to serve ELL’s overall system load and are proposed
10 as system resources rather than resources dedicated solely to Project Evest.⁹⁷

11 Mr. Kline likewise explains that the transmission facilities proposed in connection
12 with Project Evest were evaluated not solely to serve the Customer but also for the benefits
13 they provide to the overall transmission system. He testifies that the Smalling–El Dorado
14 500-kV Transmission Line, the St. Landry Switching Station, and the West Fork Creek–
15 St. Landry 500-kV Transmission Line will provide systemwide benefits. He explains that
16 these facilities will strengthen power-transfer capability, improve reliability and resilience,
17 support generator interconnection and deliverability, and facilitate future load and
18 generation growth. He further explains that the Smalling–El Dorado line is the type of
19 facility that ordinarily would be classified as a system improvement because of the broad
20 spectrum of benefits it provides.⁹⁸

⁹⁶ *Id.* at 18–19.

⁹⁷ Direct Testimony of Laura Beauchamp at 40-41.

⁹⁸ Direct Testimony of Daniel Kline at 12–13, 15–16, 21.

1 Based on the information provided by ELL, I conclude that ELL has evaluated and
2 presented the principal market and planning impacts associated with Project Evest. The
3 Company evaluated not only the incremental costs of serving the Customer, but also the
4 impacts on wholesale production costs, fuel costs, capacity requirements, transmission
5 planning, resource planning, Customer revenues, and broader system operations. Whether
6 one ultimately agrees with every modeling assumption or policy judgment reflected in
7 those analyses is a separate question addressed elsewhere in this testimony. I discuss my
8 consideration of the results of this modeling in Section IV.D. that reviews ELL's proposed
9 TCI. For purposes of this Large Load Guideline, however, I find that ELL has
10 demonstrated that it considered the principal market and planning impacts associated with
11 the proposed Project before selecting its proposed supply plan.

12 **10. LARGE LOAD GUIDELINE #5: RATE DESIGN AND COST**
13 **RECOVERY**

14 **Q71. WHAT IS THE PURPOSE OF LARGE LOAD GUIDELINE #5 ADDRESSING**
15 **RATE DESIGN AND COST RECOVERY?**

16 A. Large Load Guideline #5 is intended to ensure that the utility has developed a rate design
17 and cost recovery framework that appropriately allocates the costs associated with serving
18 the proposed large load while protecting existing customers from cost shifting. Unlike the
19 preceding Large Load Guidelines, which focus primarily on the physical resources
20 necessary to provide reliable electric service and the operational impacts of integrating a
21 large customer into the utility's system, this Large Load Guideline focuses on the financial
22 and ratemaking mechanisms through which those costs will ultimately be recovered.

23 More specifically, this Large Load Guideline considers whether the utility has
24 reasonably identified the incremental costs associated with serving the proposed load,

1 developed an appropriate rate structure to recover those costs from the customer, and
2 established mechanisms that reasonably protect existing customers from bearing costs that
3 are properly attributable to the new load. The Large Load Guideline also contemplates
4 whether the proposed rate design appropriately allocates both costs and benefits between
5 the new customer and existing customers while providing sufficient transparency for future
6 regulatory review.

7 For a project of this magnitude, these considerations are particularly important
8 because Project Evest will require substantial investments in generation, transmission,
9 battery storage, and related infrastructure over an extended period of time. Accordingly,
10 the Commission should be satisfied that ELL has developed a framework for recovering
11 those costs and allocating them among customers in a manner that is consistent with cost
12 causation and the public interest. I discuss and evaluate each component of ELL's rate
13 design and cost recovery proposal in the following subsections.

14 **a. RATE DESIGN: THE CIAC AGREEMENT**

15 **Q72. PLEASE DESCRIBE THE CIAC AGREEMENT AND ITS ROLE IN ENSURING**
16 **THAT ELL RECOVERS THE COST OF SERVING THE CUSTOMER.**

17 A. The CIAC Agreement complements the ESA by providing an additional mechanism
18 through which the Customer funds certain costs incurred by ELL to develop and construct
19 the facilities necessary to serve Project Evest. As explained by Mr. Kidd, the CIAC
20 Agreement requires the Customer to make cash contributions to fund approximately [REDACTED]

21 [REDACTED] of customer-funded transmission facilities and [REDACTED]
22 [REDACTED]
23 [REDACTED]. Those payments are made in advance of, or contemporaneously with,

1 construction, thereby reducing the amount of capital that must be financed by ELL and
2 limiting the costs borne by existing customers.⁹⁹

3 In addition, the CIAC Agreement contains provisions designed to ensure that if
4 estimated construction costs increase materially during development, [REDACTED]

5 [REDACTED]

6 [REDACTED]

7 [REDACTED]

8 [REDACTED].

9 The CIAC Agreement also consolidates the parties' earlier long-lead procurement
10 arrangements into a single comprehensive cost recovery framework. Prior to execution of
11 the ESA and CIAC Agreement, the Customer entered into several Long Lead Agreements
12 under which it agreed to fund the procurement and engineering of long-lead transmission
13 and generation equipment needed to support Project Evest. The ESA expressly provides
14 that the terms of those Long Lead Agreements have been incorporated into the CIAC
15 Agreement.¹⁰⁰ The CIAC Agreement further provides that those agreements are merged
16 into and superseded by the CIAC and the ESA.¹⁰¹ As a result, the CIAC Agreement serves
17 as the comprehensive agreement governing both the Customer's ongoing contribution
18 obligations and the costs previously incurred pursuant to the Long Lead Agreements.

19 Finally, Section 8 of the CIAC Agreement provides significant protection in the
20 event the project is terminated before the applicable facilities reach commercial operation.

⁹⁹ Direct Testimony of Thomas Kidd at 4-7.

¹⁰⁰ LKB-2 at 25 of 123 (Recitals to Rider 1 of the ESA).

¹⁰¹ Exhibit LKB-3 (CIAC Agreement) at 56 of 160.

1 As explained by Ms. Beauchamp, the CIAC Agreement requires a final termination
2 accounting under which the Customer remains responsible for costs incurred to construct
3 the Proposed Generators and non-retained Battery Storage Facilities, together with certain
4 other unrecouped costs, [REDACTED]

5 [REDACTED]¹⁰²

6 I view the CIAC Agreement as a critical component of ELL's overall cost recovery
7 framework. Together with the MMC and the other provisions of the ESA discussed below,
8 it substantially reduces the likelihood that existing customers will bear costs incurred to
9 construct the facilities necessary to serve Project Evest.

10 **b. RATE DESIGN: LLHPFPS-L RATE SCHEDULE WITH**
11 **MMCS AND DEFERRAL PROPOSAL**

12 **Q73. PLEASE DESCRIBE THE PROPOSED RATE DESIGN UNDER WHICH EVEST**
13 **WILL TAKE SERVICE?**

14 A. The proposed rate design is more complex than simply placing Evest on an existing retail
15 rate schedule. Rather, the proposal consists of two integrated components that operate
16 together. First, Evest will take service under the Commission-approved Large Load High
17 Load Factor Power Service Rate Schedule ("LLHLFPS-L"). Second, the ESA, through
18 Rider 1 and its appendices, contractually establishes certain billing determinants, including
19 the MMCs and the Average Demand, which determine how the LLHLFPS-L tariff will
20 operate for this particular customer.

21 As a result, the ESA does not replace the existing tariff rate schedule. Instead, it
22 establishes contractual billing terms that work in conjunction with the standard tariff rate

¹⁰² Direct Testimony of Laura Beauchamp at 28-29.

1 schedule to produce the revenues that the Company projects will be collected from Evest
2 over the term of the ESA.

3 **Q74. DESCRIBE THE MMCS.**

4 A. The MMCs consist of a schedule of fixed annual dollar amounts that remain constant for
5 defined periods before stepping down to lower fixed amounts at specified intervals over
6 the term of the Agreement. Based on my review of the Company's testimony, Exhibits
7 RDJ-2 and RDJ-4, and the Customer Agreements, I understand the MMCs to serve as the
8 primary mechanism for ensuring recovery of the assigned incremental revenue
9 requirements for in-service costs associated with serving Project Evest. The Company's
10 modeling demonstrates that the initial MMCs were established to recover the projected
11 revenue requirements associated with (i) ELL's assignment to Evest of the seven Proposed
12 Generators, the Battery Storage Facilities, the Waterford 3 uprate, the West Fork Creek–
13 St. Landry transmission facilities, and the Bayou Cove PCA; (ii) other incremental
14 operation and maintenance expenses; and (iii) the Credit Default Security. Those charges
15 establish the aforementioned schedule of minimum revenues the Company expects to
16 receive from the Customer regardless of the Customer's actual usage. The Company
17 further proposes a true-up mechanism to adjust portions of the MMCs as actual project
18 costs become known.

19 **Q75. HAVE YOU BEEN ABLE TO DETERMINE HOW THE SPECIFIC SCHEDULE**
20 **OF MMCS WAS DEVELOPED?**

21 A. Not completely. Company witness Ryan Jones explains that the MMCs were established
22 to ensure recovery of the incremental revenue requirements associated with serving Project

1 Evest, and Exhibit RDJ-2 demonstrates that, in the aggregate, the projected MMCs
2 approximately equal the projected revenue requirements over the term of the ESA.¹⁰³

3 However, I was unable to identify any testimony or workpaper that explains how
4 those cumulative revenue requirements were translated into the specific schedule of MMCs
5 contained in the ESA. Rather than varying annually to reflect annual changes in projected
6 revenue requirements of the assigned generation and transmission, the ESA establishes a
7 series of fixed monthly charges that remain constant over successive periods before
8 stepping down to a new fixed level. The information provided by ELL does not explain
9 the methodology used to determine the timing of those step reductions or the amount of
10 each revised charge. As a result, while the information provided by ELL demonstrates that
11 the cumulative MMCs are intended to recover the cumulative covered revenue
12 requirements, it does not explain how the individual monthly charges applicable during
13 each period were developed.

14 **Q76. WHAT ROLE DOES THE AVERAGE DEMAND SERVE IN THE PROPOSED**
15 **RATE DESIGN?**

16 A. For customers without an established billing history, an amount of Average Demand is to
17 be established in a customer's contract. Accordingly, the Average Demand is a contractual
18 billing determinant established in the ESA that determines the amount of revenue projected
19 to be produced under the LLHLFPS-L tariff based on the projected usage. Because the
20 LLHLFPS-L rate schedule utilizes a tiered demand-based pricing structure, the Average
21 Demand serves as the contractual billing determinant used to identify the applicable pricing
22 tier and to calculate the revenues to be produced under the tariff based on the Customer's

¹⁰³ Direct Testimony of Ryan Jones at 20-23.

1 usage. Depending on the Customer's actual usage, the resulting tariff bill applying the
2 Average Demand may be greater than or less than the applicable MMC, although the
3 Customer ultimately pays the greater of the two amounts. Company witness Ryan Jones
4 explains that the Average Demand was selected not only to support recovery of the revenue
5 requirements addressed through the MMCs, but also to produce a reasonable contribution
6 toward embedded FRP costs in excess of those incremental revenue requirements.¹⁰⁴
7 Accordingly, the Average Demand is one of the principal economic variables used to
8 determine the amount of customer revenues expected to exceed the MMCs.

9 **Q77. HOW OFTEN ARE THE MMCS AND RELATED BILLING DETERMINANTS**
10 **TRUED UP AND ADJUSTED?**

11 A. Company witness Ryan Jones explains that the proposed Billing Terms provide several
12 opportunities to update the MMCs and the Average Demand over the term of the ESA.

13 First, the initial Billing Terms are updated immediately prior to the Service
14 Commencement Date. Rider 1, Section 3(B)(a) provides that the initial MMC and Average
15 Demand are to be recalculated using the most recent mutually approved capital cost
16 estimates immediately prior to the Service Commencement Date, while Appendix A
17 establishes the mechanics for calculating that initial true-up adjustment and automatically
18 amend Appendix B to reflect the revised Billing Terms. Mr. Jones explains that the most
19 recent Class 3 estimates for the Generation Assets and the ELL-Funded Transmission
20 Project will be used as the basis for the initial MMCs that become effective when service

¹⁰⁴ *Id.* at 22.

1 begins. He similarly explains that the Billing Terms will be trued up prior to the start of
2 the ESA.¹⁰⁵

3 Second, following the completion of construction of the Newly Constructed
4 Assets¹⁰⁶ and the applicable prudence reviews, Appendix A to Rider 1 requires the
5 Company to perform a final true-up of the Billing Terms based on the final prudently
6 incurred capital expenditures associated with Project Evest, with the revised Billing Terms
7 remaining in effect for the balance of the Original Term. Mr. Jones explains that the actual
8 costs will become the basis for recalculating both the MMCs and the Average Demand and
9 that those revised Billing Terms will remain in effect for the balance of the Original
10 Term.¹⁰⁷

11 Third, Appendix A to Rider 1 contemplates the possibility of additional
12 modifications if future circumstances demonstrate that the balance of deferred customer
13 revenues are no longer sufficient to offset the incremental revenue requirements of the
14 Newly Constructed Assets and deliver the expected customer benefits over the Original
15 Term. In that circumstance, the Company and Customer may mutually agree to modify
16 the true-up methodology based on those future circumstances.¹⁰⁸

17 Finally, Appendix A to Rider 1 of the ESA establishes an FRP Rebalancing
18 Mechanism that permits a one-time downward adjustment to the contractual Average

¹⁰⁵ *Id.* at 12-13, 35-36.

¹⁰⁶ The Newly Constructed Assets are comprised of the Generation Assets and all of the transmission facilities inclusive of the Customer Funded Transmission Projects and the ELL Funded Transmission Projects. *See* Direct Testimony of Ryan Jones at 3.

¹⁰⁷ *Id.* at 35-36.

¹⁰⁸ *Id.* at 37.

1 Demand if the FRP billing factor exceeds specified thresholds. Company witness Ryan
2 Jones explains that this mechanism is intended to provide partial protection to the Customer
3 from significant increases in FRP rates beyond those assumed when the Billing Terms were
4 established.¹⁰⁹

5 **Q78. ARE ALL OF THE REVENUE REQUIREMENT ITEMS COVERED BY THE**
6 **MMCS INCLUDED IN THE PROPOSED TRUE-UPS?**

7 A. No. Although the initial MMCs were developed using the projected revenue requirements
8 of all of the resources identified above, the proposed true-up does not appear to treat each
9 component in the same manner. Certain components, including the proposed generation
10 facilities, battery storage facilities, the Waterford 3 Uprate, and the WFC to St Landry
11 Transmission, are subject to cost true-up. Other components, including the Bayou Cove
12 PCA, Other Incremental O&M, and Credit Default Security, do not appear to be adjusted
13 through the proposed MMC true-up. Consequently, the relationship between the initial
14 revenue requirement used to establish the MMCs and the revenue requirement ultimately
15 reflected in the adjusted MMCs is not uniform across all components of the Company's
16 supply plan.

17 **Q79. IS THE AVERAGE DEMAND ALSO ADJUSTED WHEN THE MMCS ARE**
18 **TRUED UP?**

19 A. Yes. Pursuant to Rider 1 and Appendix A, the contractual Average Demand is not a fixed
20 billing determinant but instead may be updated throughout the Original Term of the ESA.
21 It is recalculated as part of the initial true-up immediately prior to the Service

¹⁰⁹ *Id.* at 37-38.

Commencement Date, recalculated again on completion of construction and the applicable prudence reviews using the final prudently incurred capital costs, and may thereafter be adjusted pursuant to the Customer Benefits Adjustment provisions and the FRP Rebalancing Mechanism if the contractual conditions for those adjustments are satisfied. Mr. Ryan Jones explains that the true-up process updates both the MMCs and the contractual Average Demand based on the actual, prudently incurred costs of the Newly Constructed Assets. He explains that the final true-up “will serve as the basis for both the true-up of the MMCs and an update to Average Demand” and that, following completion of the projects, the Company will “re-determine the Customer’s Average Demand and MMCs” using the final prudently incurred capital expenditures.¹¹⁰

Q80. WHY IS IT NECESSARY TO ADJUST BOTH THE MMCS AND THE AVERAGE DEMAND?

A. In my opinion, adjusting only one of the two billing determinants would undermine the intended operation of the proposed rate design. As discussed previously, the MMC establishes the minimum amount of revenue the Company will recover for the incremental resources constructed to serve Project Evest. The Average Demand, in turn, influences the amount of revenue expected to be produced under the LLHLFPS-L tariff and was selected not only to support recovery of those incremental revenue requirements but also to produce a reasonable contribution toward embedded FRP costs in excess of those incremental revenue requirements.

Accordingly, to maintain the initial symmetry established between the two, if the projected revenue requirements change as a result of the true-up process, both billing

¹¹⁰ *Id.* at 35-36.

1 determinants must also change. Adjusting the MMC alone would change the minimum
2 revenue floor but would not preserve the intended relationship between tariff revenues and
3 that minimum floor for the production of the expected contribution to embedded FRP costs.
4 Likewise, adjusting only the Average Demand would alter the projected tariff revenues
5 without correspondingly updating the minimum revenue protection and disrupt the
6 intended contribution to embedded FRP costs. By adjusting both billing determinants
7 using the same updated cost information, the proposed rate design preserves the
8 relationship originally negotiated between the minimum revenue recovery for the
9 incremental resources and the tariff revenues to produce the expected additional
10 contribution toward embedded system costs.

11 **Q81. PLEASE EXPLAIN THE DEFERRAL PROPOSAL PROPOSED BY RYAN**
12 **JONES.**

13 A. The Company's proposed Deferral Proposal Framework presented as Exhibit RDJ-4 is
14 intended to address a timing mismatch between the receipt of Customer revenues produced
15 by the MMCs and the recognition of the revenue requirements when the facilities being
16 constructed to serve Project Evest enter service. Mr. Jones explains that the Customer
17 begins paying substantial revenues before all of the proposed generation and transmission
18 facilities have been placed into service. Without a deferral mechanism, those revenues
19 would initially reduce FRP rates significantly, only to be followed by corresponding rate
20 increases as the new facilities enter service. According to Mr. Jones, the purpose of the
21 proposal is to avoid those repeated swings in customer rates.¹¹¹

¹¹¹ *Id.* at 28-34.

1 During the Construction Period, the Company proposes to recognize in rates only
2 the amount of Customer revenue necessary to offset the revenue requirement of the Newly
3 Constructed Assets that are in service. The remaining Customer revenues would be
4 recorded as a regulatory liability rather than immediately flowing through the FRP. That
5 regulatory liability would be excluded from rate base until all of the Newly Constructed
6 Assets have been placed into service, and carrying charges would be accrued using the
7 Company's then-current weighted average cost of capital.

8 Following the Construction Period, the accumulated deferred revenues would be
9 amortized over time and used to offset the revenue requirements associated with the Evest-
10 related investments reflected in the FRP. The intended effect is to better align the
11 recognition of Customer revenues with the revenue requirements of the associated
12 investments while avoiding significant year-to-year swings in rates for other customers.

13 Importantly, the proposal would not defer all Customer revenues. Under the
14 proposed framework, revenues collected from the Customer in excess of the MMCs
15 ("Excess Revenues") would continue to flow through the FRP and benefit customers by
16 increasing Net Operating Income unless the Company affirmatively proposes and the
17 Commission were to accept an alternative treatment in a future FRP proceeding for rate
18 stabilization purposes.

19 **Q82. DO YOU BELIEVE THE COMPANY'S PROPOSED RATE DESIGN AND**
20 **DEFERRAL FRAMEWORK ARE INTENDED TO RECOVER THE ANNUAL**

**COST OF THE ASSIGNED COST TO SERVE EVEST AND CONTRIBUTE TO
THE EMBEDDED FRP COSTS?**

A. Generally, yes. In my opinion, the Company devoted considerable effort to developing a rate design intended to accomplish several objectives simultaneously. The proposal seeks to ensure recovery of the incremental annual costs associated with serving Project Evest during the term of the ESA, provide a meaningful contribution toward embedded FRP costs, avoid significant year-to-year swings in rates, and to allow for adjustable billing terms that can reflect changes in major construction costs as they become known. Conceptually, I believe those are reasonable objectives and the overall framework is thoughtfully designed.

That said, the proposal is also highly customized and necessarily relies on numerous assumptions regarding future project costs, construction schedules, purchased power costs, and the successful completion of all of the facilities comprising the Company's proposed supply plan. Consequently, while I generally believe the framework is sound, I do have several questions and concerns regarding how the proposal would function if future events differ materially from those assumed in the Company's modeling.

Q83. WHAT ARE YOUR PRINCIPAL CONCERNS?

A. First, I have concerns regarding the treatment of the Bayou Cove PCA. Although Bayou Cove is included in the development of the initial MMCs, it does not appear to be included within the proposed cost true-up. The Bayou Cove agreement is scheduled to expire during the term of the ESA, and the information provided by ELL does not readily explain how the MMCs would be adjusted if replacement purchased capacity ultimately costs materially more or less than the assumptions embedded in the initial billing terms. Because the future

1 cost of replacement capacity is presently unknown, this creates uncertainty regarding
2 whether the MMCs will continue to recover the revenue requirements they were intended
3 to address. The MMCs should be trued up to cover any material changes in cost for the
4 capacity that will need to be replaced on the expiration of the Bayou Cove PCA. To the
5 extent the MMCs are not updated any additional material costs should be considered in any
6 subsequent review of the Project Evest benefits to potentially support the recovery of any
7 stranded assets.

8 Second, I have concerns regarding the treatment of significant changes to the
9 Company's proposed resource portfolio. The Company's proposal assumes assigning to
10 Evest the annual costs for the construction of seven generation facilities, three battery
11 storage facilities, the Waterford 3 Uprate and related transmission investments. However,
12 the information provided by ELL does not clearly explain how the contractual billing terms
13 would be affected if one or more of those projects were cancelled, materially delayed, or
14 replaced with an alternative resource. While the true-up mechanism addresses changes in
15 project costs, it is less clear how the framework responds to changes in the underlying
16 supply plan. For example, what would happen to the MMC true up if one of the battery
17 storage facilities was ultimately not constructed? I was unable to determine from the
18 information provided by ELL whether the Company would procure replacement capacity,
19 how such a replacement resource would be selected, whether and how its costs would be
20 incorporated into the MMCs, or when any such modification to the rate design would
21 occur.

22 These questions do not necessarily render the proposed framework unreasonable.
23 Rather, they identify circumstances that, in my opinion, warrant additional clarification

1 before the Commission approves the proposed billing framework. Consistent with my
2 earlier recommendations, nothing in the Commission's Order in this proceeding should be
3 construed as relieving ELL of responsibility for changes in its proposed supply plan or its
4 implementation of the Customer Agreements. Any risks associated with those matters
5 should remain the responsibility of ELL and should not be transferred to other ratepayers.
6 Additionally, to keep the Commission informed related to this obligation, ELL should be
7 required to provide the Commission with all updates of the MMCs and Average Demand
8 as well as notice of any supply change plans once known.

9 **c. RATE DESIGN: STORM AND RESILIENCE RIDERS**

10 **Q84. PLEASE DESCRIBE THE STORM AND RESILIENCE RIDERS.**

11 A. The Storm Cost Recovery Riders and the Resilience Rider and impose charges and credits
12 on ELL's customer to pay for (i) securitizations of costs associated with prior hurricanes
13 and storms and (ii) a Commission approved resilience plan to harden the transmission and
14 distribution infrastructure to provide more resilience to such weather events. The billing
15 for the Storm Cost Recovery Rider is inclusive of both the costs associated with the
16 securitizations and Storm Cost Offsets for tax and other benefits that are credited to
17 customers benefit to reduce the overall costs associated with the storm recovery
18 (collectively referred to as the "Storm Riders").

19 **Q85. ARE THE CUSTOMER'S CONTRIBUTIONS UNDER THE STORM RIDERS**
20 **AND THE RESILIENCE RIDER ALSO RELEVANT TO YOUR**
21 **CONSIDERATION FOR CERTIFICATION?**

22 A. Yes. In addition to the revenues recovered through the LLHLFPS-L tariff and the
23 "MMCs", the Customer is also expected to make contributions under ELL's Storm and

1 Resilience Riders. These rider revenues represent additional sources of revenue associated
2 with serving Project Evest that benefit ELL's other customers as they represent amounts
3 those ratepayers would have to pay absent Evest. Accordingly, Mr. Datta recognizes these
4 revenues as additional customer benefits in calculating the TCI discussed later in my
5 testimony.

6 **Q86. PLEASE DESCRIBE THE CUSTOMER'S CONTRIBUTIONS UNDER THE**
7 **RESILIENCE RIDER.**

8 A. The Customer will generally be subject to ELL's Resilience Rider in the same manner as
9 other similarly situated retail customers. However, during any billing period in which the
10 Customer pays the applicable MMC rather than the amount otherwise produced by the
11 LLHLFPS-L tariff, the Resilience Rider does not apply.¹¹² Stated differently, the Customer
12 contributes to the Resilience Rider only in those periods in which the Customer's bill is
13 determined by the applicable tariff rather than by the contractual MMC. These Resilience
14 Rider revenues therefore represent an additional source of customer benefit reflected in
15 ELL's TCI analysis, but only for those periods in which the rider is applicable.

16 **Q87. PLEASE DESCRIBE THE CUSTOMER'S CONTRIBUTIONS UNDER THE**
17 **STORM RIDERS.**

18 A. The Storm Riders is treated differently. Unlike the Resilience Rider, the Storm Riders
19 continue to apply even during periods in which the Customer pays the applicable MMC.¹¹³
20 Under the Customer Agreements, the applicable MMC serves as the billing determinant on
21 which the Storm Riders charge is calculated during those periods. As a result, ELL expects

¹¹² RLS-010 (ELL Response to Staff 1-36).

¹¹³ *Id.*

1 to continue receiving Storm Riders revenues from the Customer even when the contractual
2 MMC exceeds the amount that otherwise would have been due from Evest under the
3 LLHLFPS-L tariff. These revenues therefore represent an additional benefit to ELL's other
4 customers and are appropriately recognized in the TCI analysis.

5 **Q88. ARE THERE ANY OTHER OBSERVATIONS OR CONCERNS YOU HAVE**
6 **REGARDING THE STORM AND RESILIENCE RIDERS THAT ELL HAS NOT**
7 **DIRECTLY ADDRESSED?**

8 A. Yes. The Resilience Rider is updated twice annually to update the revenue requirement of
9 the eligible Resilience Rider investments. The revenue requirement is allocated among
10 customer classes in proportion to each class's share of the total Applicable Base Revenues
11 from the Test Year FRP filing. The Storm Cost Riders, including the associated offsets,
12 are derived using a similar construct.

13 My concern is that the assumptions embedded in these riders do not match the
14 circumstances of the Evest load and billing terms, and as a result the riders will not bill
15 Evest, or credit ELL's other customers, in manner consistent with the assumptions that
16 existed at the time they were designed and in a manner such that they remain in the public
17 interest. This concern has two parts. First, ELL's proposed ratemaking treatment of
18 Evest's revenue could result in an over-collection by ELL instead of being directed to the
19 capital improvements the Resilience Rider was intended to facilitate. Second, because the
20 allocators used to assign the Resilience Plan costs are fixed under the rider, they do not
21 account for the significant change in those factors that the Evest and Laidley load produces.

**Q89. PLEASE DESCRIBE MORE FULLY HOW THE RESILIENCE RIDER FACTORS
ARE DEVELOPED.**

A. The eligible Resilience Plan revenue requirement is functionalized between transmission and distribution for purposes of allocating the cost of the Resilience Plan to transmission and distribution customers. Transmission-voltage customers are assigned a portion of both transmission and distribution portions of the Resilience Plan costs based on static factors ordered by the Commission under the circumstances that existed at the time the Resilience Plan and Rider were adopted. For the distribution portion of Resilience Plan costs, transmission-voltage customers are assigned a static 16% of the revenue requirement. For the transmission portion of the Resilience Plan costs, transmission-voltage customers are assigned a static 42.59%, which represents transmission's 12CP demand factor from ELL's last filed cost of service study. The balance of the Resilience Plan revenue requirement is assigned to distribution-voltage customers only. Each portion is then converted to a percentage factor of Applicable Base Revenue: a combined transmission and distribution factor that is billed to all retail customers, and a distribution factor that is billed only to customers served at distribution voltage. The Applicable Base Revenue figures used as the denominator are taken from ELL's most recent FRP filing.

Two additional features of the Resilience Rider are important here. First, as noted, the Resilience Rider does not apply to contract minimums, such as Evest's MMC obligations. Second, the Resilience Rider's true-up mechanism is a true-up to costs, not to revenues, meaning it compares the actual Resilience Plan revenue requirement to the

1 projected revenue requirement but does not reconcile the revenues actually billed and
2 collected under the rider against the revenue requirement.¹¹⁴

3 **Q90. AS TO THE SECOND FEATURE, DO YOU AGREE WITH THE TREATMENT**
4 **OF EVEST REVENUE WITHIN THE FRP?**

5 A. Yes. As I noted previously, the primary purpose of ELL's deferred revenue proposal, along
6 with the MMC structure, is to protect ELL's other customers from the impacts of the costs
7 associated with serving that load, such that the benefits of the proposal would be felt by
8 customers without the lumpiness of significant rate increases and decreases. ELL's
9 proposal to treat Evest revenue as a direct offset to the retail revenue requirement within
10 the FRP – and to time that offset through the operation of the deferral mechanism –
11 provides a reasonable structure to achieve that goal. But it does create certain issues with
12 the Resilience Rider (and other riders) that if not addressed could lead to adverse
13 consequences.

14 **Q91. WHY DOES THE PROPOSED FRP TREATMENT CREATE A PROBLEM FOR**
15 **THE RESILIENCE RIDER IN TERMS OF OVER-COLLECTION?**

16 A. Because if Evest's revenue is treated as a revenue offset to the retail revenue requirement,
17 as ELL proposes for the FRP, then that revenue will not appear as Applicable Base Revenue
18 for the LLHLFPS-L class in the FRP filing that supplies the Resilience Rider's
19 denominator. Yet Evest, taking service under Rate Schedule LLHLFPS-L, will still be
20 billed the Resilience Rider on its actual base-rate revenue (when it is billed on actual usage

¹¹⁴ This feature is prevalent throughout ELL's FRP where the risks of under and over-recovery are born by ELL instead of customers (e.g., ELL's MISO Cost Recovery Mechanism ("MCRM"), Transmission Recovery Mechanism ("TRM"), and Distribution Recovery Mechanism ("DRM")).

1 rather than on its MMC). The result in that situation is that Evest is charged the rider on
2 revenue that was never, and never will be, included in the base against which the rider
3 factor is set. ELL therefore would collect more than the Resilience Plan revenue
4 requirement.

5 **Q92. DO YOU HAVE A RECOMMENDATION TO ADDRESS YOUR CONCERNS?**

6 A. There may be other ways to achieve the same goal, but one method of ensuring no over-
7 collection could be for ELL to treat Evest's revenues within the Resilience Rider the same
8 way it proposes to treat them within the FRP. Specifically, ELL could calculate the
9 Resilience Rider without considering Evest within Applicable Base Revenues and then
10 credit Evest's Resilience Plan revenue as an offset to the Resilience Plan revenue
11 requirement. This mirrors the FRP treatment and would eliminate the over-collection
12 issue.

13 **Q93. DO YOU ALSO SEE ANOTHER PROBLEM WITH THE FACTORS USED IN**
14 **THE RESILIENCE RIDER TO ALLOCATE COSTS TO TRANSMISSION**
15 **CUSTOMERS?**

16 A. Yes. As I noted, both the distribution and transmission portions of the Resilience Plan
17 costs are allocated to transmission-level customers based on factors that are frozen under
18 the Commission's prior order. For the distribution costs, this factor is 16%, which was a
19 negotiated number stemming from ELL's allocations in storm cost proceedings where
20 roughly 33% of distribution level costs were assigned to transmission customers. For the
21 transmission costs, this factor is 42.59%, which was based on the calculation of
22 transmission customers contribution to the 12 coincident peak factor in ELL's last Cost of
23 Service study. Certainly, the presence of Evest's load will increase transmission

1 Customers' contribution to coincident peak, and therefore a new Cost of Service study
2 would show that more of the Resilience Plan's costs should be allocated to transmission
3 customers. Additionally, I believe the presence of Evest likely would have driven the
4 Commission to consider an allocation of distribution costs different than the fixed 16%
5 ordered by the Commission. But as I noted, both factors are static.

6 **Q94. DO YOU THINK ANYTHING SHOULD BE DONE ABOUT THIS SEEMINGLY**
7 **INEQUITABLE RESULT?**

8 A. I think that the Commission should consider altering these factors to more equitably
9 allocate the resilience plan costs to the transmission class (with the Evest load), and more
10 broadly allocate the distribution level costs to a much larger transmission class that now
11 includes the Evest load. The intent should be to ensure that certain rate classes are not
12 receiving a benefit under the Resilience Plan that is disproportionate to the risk of potential
13 costs that would flow through other mechanisms of the FRP.

14 **Q95. DO THESE CONCERNS APPLY EQUALLY TO THE STORM RIDERS?**

15 A. I do not have the same over-collection concern for the Storm Riders. Unlike the Resilience
16 Rider, the Storm Riders are assessed on contract minimums. They are also calculated using
17 forecasted rather than historical revenues. So, Evest's determinants, including its MMCs,
18 should be fully captured. Second, the Storm Riders are trued up under the Commission's
19 financing orders, and that true-up reconciles collections at least semi-annually and corrects
20 any over- or under-collection against the remaining securitized balance. As a result, an
21 over-collection under the storm cost riders is ultimately returned to customers through a
22 reduced charge in a later period, rather than retained as it would be under the Resilience
23 Rider.

1 I do, however, have the same concerns with the Storm Riders as I did with the
2 Resilience Rider with regard to the factors used to allocate costs to transmission-level
3 customers. As with the Resilience Rider, those factors included in the storm cost riders are
4 fixed and do not adequately reflect a world in which the Evest load exists. As such, to the
5 extent the governing finance orders allow, ELL should take steps to correct the application
6 of the Storm Riders to Evest in a manner consistent with what I have recommended for the
7 Resilience Rider.

8 **Q96. DO YOU BELIEVE ANY POTENTIAL CERTIFICATION REQUESTED IN THIS**
9 **DOCKET SHOULD BE CONDITIONED ON A RESOLUTION OF THESE**
10 **CONCERNS?**

11 A. I do, and I propose such a condition in my conditional recommendation below.

12 **d. COST RECOVERY**

13 **Q97. HAVE YOU REVIEWED WHETHER THE PROPOSED RATE DESIGN**
14 **DISCUSSED ABOVE PROVIDES ADEQUATE COST RECOVERY**
15 **PROTECTION TO ELL'S OTHER RATEPAYERS?**

16 A. Yes. In my opinion, that question is broader than simply determining whether the proposed
17 CIAC recovery, rate schedule, and billing terms are designed to recover the incremental
18 costs associated with serving Project Evest.

19 Demonstrating that the proposed Customer Agreement billing terms are designed
20 to recover the incremental revenue requirements of assigned costs and a contribution to
21 embedded cost during the initial twenty-year term of the ESA does not, by itself, fully
22 answer whether ELL's other customers are adequately protected from all material financial
23 risks associated with the proposal. That broader question necessarily requires

1 consideration of circumstances such as early termination of the ESA, non-renewal at the
2 end of the initial term, changes to the proposed supply plan, and other events that could
3 affect the continued recovery of the costs associated with the facilities constructed to serve
4 the Customer.

5 **Q98. HOW DO YOU INTEND TO ADDRESS THOSE ISSUES?**

6 A. I address those issues in two subsequent sections of my testimony. First, in my following
7 discussion in Section IV.C.11. regarding Large Load Guideline #4, I evaluate the
8 contractual protections against stranded asset and exit risk, including the remedies
9 available under the Customer Agreements in the event of an early termination of the ESA
10 and the potential impacts associated with non-renewal at the conclusion of the initial
11 twenty-year term. Those contractual protections are central to determining whether the
12 financial risks associated with the proposed facilities remain with the Customer or could
13 ultimately be shifted to ELL's other ratepayers.

14 Second, in my following discussion in Section IV.D, I review the integrated
15 economic assessment presented by Mr. Datta. That assessment, summarized in Exhibit
16 SD-2, is intended to evaluate whether, after considering the combined effects of the
17 proposed rate design, customer revenues, rider revenues, fuel impacts, transmission costs,
18 capacity impacts, customer-funded programs, and the potential effects of customer non-
19 renewal, ELL's other customers remain economically better off as a result of serving
20 Project Evest. Because that assessment necessarily incorporates many of the issues
21 discussed throughout my testimony, I believe it is more appropriately evaluated after each
22 of those individual components has first been examined.

**Q99. WHAT IS YOUR POSITION RELATED TO LARGE LOAD GUIDELINE #5
RATE DESIGN AND COST RECOVERY AT THIS POINT IN YOUR
TESTIMONY?**

A. As mentioned above, a full analysis of cost recovery requires the review of stranded asset risk and the TCI which I fully discuss below. However, solely focusing on the rate design aspect of this Large Load Guideline, I find the following:

1. The CIAC Agreement is a critical component to ELL's proposed overall cost recovery and substantially reduces the likelihood that existing customers will bear costs to construct the facilities assigned to serve Evest;
2. The proposed LLHLFPS-L Rate schedule complemented with the contractual MMC and Average Demand billing provisions, and further complemented with ELL's proposed deferral, together seek to (i) ensure recovery of the incremental annual costs associated with serving Project Evest during the term of the ESA, (ii) provide a meaningful contribution toward embedded FRP costs, (iii) avoid significant year-to-year swings in rates, and (iv) allow for adjustable billing terms that can reflect changes in major construction costs as they become known. Nevertheless, I present my concerns related to how changes to the Company's proposed resource portfolio may impact that rate design. Accordingly, I recommend that nothing in any Commission's Order in this proceeding should be construed as relieving ELL of responsibility for changes in its proposed supply plan or its implementation of the Customer Agreements, including the management of the rate design. Any risks associated with those matters should remain the responsibility of ELL and should not be transferred to other ratepayers.

1 3. I acknowledge that in addition to the base rates and FRP charged in accordance
2 with LLHLFPS-L, as enhanced by Rider 1, Evest is proposed to additionally be
3 supplying revenues charged by the Storm Riders and may be supplying revenues
4 charged by the Resilience Riders. Those Evest revenues will benefit other
5 ratepayers as reductions in what they otherwise would pay. However, I identify
6 significant concerns I have with how the proposed Evest rate design may cause the
7 current allocations of those riders to allow for an overcollection by ELL and may
8 produce inequitable allocations amongst all ratepayers. Accordingly, I recommend
9 that the Commission require ELL to address these concerns as a condition to any
10 certification it may grant.

11 **11. LARGE LOAD GUIDELINE #4: STRANDED ASSET AND EXIT**
12 **RISK**

13 **Q100. WHAT DOES THE COMMISSION'S FOURTH LARGE LOAD GUIDELINE**
14 **ADDRESS?**

15 A. The Commission's fourth Large Load Guideline addresses whether the utility has
16 adequately protected existing customers from the financial risks associated with
17 constructing generation, transmission, and related infrastructure to serve a large load that
18 may later terminate or materially reduce its electric service requirements. The Large Load
19 Guideline is intended to evaluate whether the utility has appropriately mitigated the risk
20 that existing customers could be left paying for stranded assets or other unrecovered costs
21 if the anticipated load does not materialize or ceases to take service. Specifically, the Large
22 Load Guideline provides that the utility should demonstrate that:

- 23 • reasonable protections exist against stranded generation, transmission, and fuel
24 infrastructure;

- the contractual term appropriately aligns with the useful lives of the assets being constructed;
- any excess generation remaining at the end of the contractual term can be economically utilized by the utility's remaining customers, if applicable;
- adequate financial security, including corporate guarantees where appropriate, exists to protect existing customers from paying for facilities that become unnecessary; and
- the contractual arrangements adequately address the risks associated with partial reductions in the customer's electric load

**a. GENERAL REGULATORY PRINCIPLES GOVERNING
THE FUTURE RATEMAKING TREATMENT OF
STRANDED ASSETS**

Q101. WHAT IS MEANT BY THE TERM "STRANDED ASSET"?

A. Although the term "stranded asset" does not appear to have a single universally accepted legal definition, it is generally used in utility regulation to describe utility property or investments that remain unrecovered after the assets cease to provide the utility service or economic benefits originally anticipated. Stranded assets may arise for many reasons, including changes in customer demand, technological developments, environmental requirements, regulatory changes, market conditions, customer departures, or the early retirement or underutilization of utility facilities.

Importantly, the existence of a stranded asset does not itself determine whether, or to what extent, the remaining investment should ultimately be recovered from customers. Rather, the existence of a stranded asset merely presents a ratemaking question that must be resolved by the appropriate regulatory authority based on the particular facts and circumstances existing at that time.

As one former Administrative Law Judge for the FERC explains:

When prudence combines with disappointment, who bears the extra cost—shareholders or customers?... The consistent principle across the cases is

1 this: With respect to prudent actions with uneconomic outcomes,
2 commissions have a full range of options, from full recovery plus profit, to
3 no recovery and no profit, and all points in between.¹¹⁵
4

5 **Q102. DOES A DETERMINATION THAT UTILITY FACILITIES ARE PRUDENT OR**
6 **IN THE PUBLIC INTEREST AUTOMATICALLY DETERMINE HOW ANY**
7 **FUTURE STRANDED INVESTMENT ASSOCIATED WITH THOSE**
8 **FACILITIES WILL ULTIMATELY BE TREATED?**

9 A. No. Certification of utility facilities, findings of prudence, and the future ratemaking
10 treatment of utility investments are separate regulatory determinations that occur at
11 different points in the life of an investment and answer fundamentally different questions.
12 When the Commission certifies new utility facilities, it evaluates whether construction of
13 those facilities is reasonable based on the facts known at the time of certification. That
14 determination necessarily relies on forecasts of future customer requirements, economics,
15 technology, fuel markets, environmental regulation, and numerous other assumptions.
16 Those forecasts may ultimately prove accurate or inaccurate as circumstances evolve over
17 time. If circumstances later change such that facilities become underutilized, retired early,
18 or otherwise stranded, the question before the Commission is fundamentally different.
19 Also, the utility maintains a continuing obligation of prudence in managing the utilization
20 of its assets for the benefits of its customers. Rather than asking whether construction was
21 reasonable when undertaken, the Commission must determine the appropriate ratemaking
22 treatment of the remaining investment based on the facts existing when recovery is sought.

¹¹⁵ Scott Hempling, Allocating the Risks of Utility Capital Expenditures (National Regulatory Research Institute).

1 The United States Supreme Court recognized this distinction in *Duquesne Light*
2 *Co. v. Barasch*, holding that a state regulatory commission does not violate the Constitution
3 merely because it disallows recovery of capital investments that are not used and useful in
4 service to the public, even where those expenditures were prudent and reasonable when
5 made.¹¹⁶

6 Accordingly, prudence and ultimate recovery are related but distinct regulatory
7 inquiries.

8 **Q103. WHY IS THAT DISTINCTION IMPORTANT IN THE CONTEXT OF STRANDED**
9 **ASSETS?**

10 A. Because stranded assets typically arise not from imprudent decisions, but from changed
11 circumstances. Utility regulation necessarily involves forecasting. When the Commission
12 considers a request to construct major utility facilities, it must make decisions based on
13 reasonable forecasts of future conditions. Those forecasts may ultimately prove accurate
14 or inaccurate. However, changes in those forecasts over time do not, by themselves,
15 establish whether future ratemaking treatment should or should not be allowed.

16 For example, over the life of a utility investment:

- 17 • Demand forecasts may change;
 - 18 • Fuel markets may change;
 - 19 • Technology may evolve;
 - 20 • Environmental requirements may change;
 - 21 • Customers may leave;
 - 22 • Large industrial facilities may close;
 - 23 • Economic conditions may deteriorate; or
 - 24 • New opportunities may arise for alternative uses of the facilities.
- 25

¹¹⁶ 488 U.S. 299 (1989).

1 None of these events necessarily demonstrates that the original investment decision was
2 imprudent. Rather, they illustrate why the appropriate ratemaking treatment of stranded
3 assets cannot reasonably be determined decades in advance. Instead, that determination
4 must be made based on the facts and circumstances that exist if and when the assets
5 ultimately become stranded.

6 **Q104. HAS THE COMMISSION PREVIOUSLY DISTINGUISHED BETWEEN**
7 **AUTHORIZING ACCOUNTING TREATMENT THAT TRACKS COSTS**
8 **ASSOCIATED WITH STRANDED ASSETS AND APPROVING ULTIMATE**
9 **RECOVERY OF THOSE COSTS?**

10 A. Yes. The Commission has recognized this distinction. One of the clearest examples
11 appears in the recent LPSC Docket No. U-35753 Dolet Hills proceeding. While the
12 proceeding was pending, the Commission ordered Cleco Power and SWEPCO to establish
13 regulatory assets for certain deferred lignite production costs. However, the Commission
14 expressly limited the effect of that accounting treatment by stating:

15 [T]hese regulatory assets may be used for accounting purposes only. This
16 accounting order constitutes neither allowance nor disallowance of
17 recovery.¹¹⁷
18

19 That statement is significant because it demonstrates that establishing a regulatory asset,
20 even by Commission order, does not predetermine whether the deferred costs will
21 ultimately be recoverable. Instead, the Commission expressly reserved that issue for later
22 determination.

¹¹⁷ LPSC Order No. U-35753-A (May 16, 2024) (*In re: Joint Application for: (I) Authorization to Close the Oxbow Mine; and (II) Authorization to Include and Defer Certain Accelerated Mine Closing Costs in Fuel and Related Ratemaking Treatments*) at 2-3 (quoting LPSC Order No. U-35753 (April 8, 2021)).

**Q105. DID THE COMMISSION SIMILARLY RESERVE FUTURE RATEMAKING
ISSUES AFTER EXPANDING THE DOLET HILLS PROCEEDING?**

A. Yes. When the Commission expanded the proceeding to examine the early retirement of Dolet Hills, it again emphasized that future recovery issues remained open.

Specifically, the Commission directed that the proceeding include review of:

- whether retirement was prudent;
- whether any disallowances were appropriate;
- how actual net book value should be treated;
- whether alternative ratemaking mechanisms should be adopted; and
- whether refunds or other adjustments might ultimately be appropriate.

The Commission further explained that its prior authorization to establish regulatory assets did not constitute a finding of prudence and that the deferred costs remained subject to future review, modification, and potential refunds. Again, the Commission distinguished between authorizing an accounting mechanism and determining the ultimate ratemaking treatment of the deferred costs, intentionally reserving that determination until the relevant facts had been fully developed.

**Q106. DOES THE PRESIDING JUDGE'S FINAL RECOMMENDATION IN THE
DOLET HILLS PROCEEDING PROVIDE ADDITIONAL GUIDANCE
REGARDING FUTURE RECOVERY OF STRANDED ASSETS?**

A. Yes. Although the Administrative Law Judge's Final Recommendation was not ultimately adopted because the parties settled the proceeding, it contains one of the clearest discussions I have found distinguishing an accounting mechanism that allows for future recovery from a guarantee of recovery. Specifically, the Recommendation states:

1 “No such ‘guaranteed recovery’ existed for a stranded asset.”¹¹⁸

2 I find that reasoning to be consistent with traditional principles of utility regulation. Prior
3 Commission approval of an investment, or approval of a mechanism through which costs
4 may later be presented for recovery, does not itself constitute a binding determination that
5 all future costs associated with that investment will necessarily be recoverable regardless
6 of the facts and circumstances existing when recovery is later requested.

7 **Q107. DOES THE COMMISSION’S FINAL RESOLUTION OF THE DOLET HILLS**
8 **PROCEEDING FURTHER ILLUSTRATE THAT STRANDED ASSET**
9 **RECOVERY IS NOT AUTOMATIC?**

10 A. Yes. Although the Dolet Hills proceeding concluded through an uncontested settlement
11 rather than litigated Commission findings, the final Commission resolution nevertheless
12 illustrates that the remaining costs associated with stranded facilities is not simply accepted
13 for full recovery without further review, even if the Commission allows those costs to be
14 recorded as a deferred asset for accounting purposes. Under the settlement that was
15 approved by the Commission, CLECO and SWEPCO agreed to reduce their recovery of
16 the deferred Dolet Hills costs disallowances.¹¹⁹

17 The settlement itself expressly states that it shall have no precedential effect and
18 may not be cited as precedent in future proceedings. Accordingly, I do not rely on the
19 settlement to establish a legal rule. Rather, I cite it only to illustrate that even where the

¹¹⁸ Final Recommendation of Administrative Law Judge, No. U-35753 (Feb. 2, 2024) (*In re: Joint Application for: (I) Authorization to Close the Oxbow Mine; and (II) Authorization to Include and Defer Certain Accelerated Mine Closing Costs in Fuel and Related Ratemaking Treatments*) at 27.

¹¹⁹ *Id.*

1 underlying investments had already been made, the Commission's ultimate resolution
2 focuses on determining the appropriate amount, timing, and method of recovery rather than
3 assuming that all remaining investment is automatically recoverable.

4 **Q108. DOES THE LITTLE GYPSY PROCEEDING ILLUSTRATE THE SAME**
5 **REGULATORY APPROACH?**

6 A. Yes. Like Dolet Hills, the Little Gypsy proceeding illustrates that certification of a
7 generating project does not eliminate the Commission's obligation to later determine the
8 appropriate ratemaking treatment after circumstances materially changed. When
9 construction of Little Gypsy ceased, Entergy was required to return to the Commission to
10 address the appropriate treatment of the resulting stranded investment. The Little Gypsy
11 proceeding similarly demonstrates that even after a generating project had previously been
12 certified as prudent, later developments resulted in a separate proceeding addressing
13 cancellation of the project, quantification of recoverable costs, carrying charges, customer
14 allocations, securitization, offset mechanisms, and numerous other ratemaking issues.

15 Importantly, when the Commission approved long-term suspension of the project,
16 it expressly reserved future consideration of:

- 17 • the prudence of the Company's management decisions;
 - 18 • whether project costs should ultimately be recovered;
 - 19 • the manner of any recovery; and
 - 20 • whether the project should ultimately be cancelled or merely suspended.¹²⁰
- 21

¹²⁰ LPSC Order No. U-31894 (June 24, 2011) (*In re: Application of Entergy Louisiana, LLC For Approval To Securitize Investment Recovery Costs Related To The Little Gypsy Unit 3 Repowering Project Authorizing The Company to Finance Its Investment Costs Pursuant To Act 988*) at 3 (quoting Order No. U-30192-C (May 22, 2009)).

1 Likewise, the later settlement orders expressly state that they are nonprecedential.
2 Nevertheless, the proceedings illustrate the same regulatory principle reflected in Dolet
3 Hills: prior certification does not eliminate the need for a later, fact-specific determination
4 regarding the appropriate ratemaking treatment of remaining investment after
5 circumstances materially changed.

6 **Q109. DOES THIS TESTIMONY RECOMMEND THAT THE COMMISSION**
7 **PREJUDGE THE ADEQUACY OF THE CUSTOMER AGREEMENTS OR ANY**
8 **PARTICULAR RISK MITIGATION MECHANISM?**

9 A. No. My testimony is not intended to prejudge whether any particular guaranty, security
10 arrangement, contractual obligation, or other mitigation measure will ultimately prove
11 sufficient under every potential future circumstance. In fact, the Commission has not been
12 requested by ELL to express an opinion on, or provide a prudence determination related
13 to, any of these things. This is a certification proceeding for assets being used to serve the
14 Customer. Accordingly, my opinion is that the Commission should evaluate whether those
15 provisions appear reasonable today solely for purposes of certification while recognizing
16 that, should stranded assets ultimately occur, the effectiveness of those mitigation measures
17 can only be evaluated based on the facts that actually exist at that time.

18 **Q110. WHY DO THE LARGE LOAD GUIDELINES REQUIRE APPLICANTS TO**
19 **DISCUSS REASONABLE PROTECTIONS AGAINST STRANDED ASSET RISK**
20 **RATHER THAN REQUIRING THE COMMISSION TO PREDETERMINE THE**
21 **FUTURE RATEMAKING TREATMENT OF STRANDED ASSETS?**

22 A. Because proposed protections can be evaluated prospectively, while ratemaking treatment
23 cannot. At the time a large-load proposal is considered, the Commission may reasonably

1 evaluate whether contractual provisions, financial protections, guarantees, customer
2 obligations, security arrangements, and other mechanisms appear likely to reduce the risk
3 that future stranded costs will occur.

4 What cannot reasonably be determined at that time is how any remaining stranded
5 investment should ultimately be treated decades later if those protections prove partially
6 effective, wholly effective, or ineffective. That future determination necessarily depends
7 on facts that do not yet exist. For example, among other considerations, the Commission
8 could reasonably consider:

- 9 • why the asset became stranded;
- 10 • whether the circumstances were foreseeable;
- 11 • whether the utility prudently administered the applicable agreements;
- 12 • whether contractual remedies were fully enforced;
- 13 • the effectiveness of the design of the guaranties or other credit support;
- 14 • amounts recovered through litigation, settlement, or liquidation;
- 15 • insurance recoveries;
- 16 • salvage value;
- 17 • market value;
- 18 • replacement customers;
- 19 • continued system usefulness;
- 20 • depreciation already recovered;
- 21 • benefits previously received by customers;
- 22 • remaining useful life;
- 23 • federal tax benefits;
- 24 • securitization opportunities
- 25 • whether the utility reasonably mitigated damages
- 26 • whether remaining facilities continue to provide value to the system
- 27 • whether costs were otherwise recovered from the customer responsible for creating
- 28 the stranded investment; and
- 29 • any other facts relevant to determining just and reasonable rates.
- 30

1 Because none of those facts can presently be known with certainty, the Commission
2 cannot reasonably predetermine today what future ratemaking treatment would be
3 appropriate.

4 **Q111. PLEASE SUMMARIZE YOUR OPINION REGARDING THE PROPER**
5 **REGULATORY TREATMENT OF STRANDED ASSET RISK.**

6 A. In my opinion, the Commission's Large Load Guidelines appropriately distinguish
7 between requiring applicants to demonstrate reasonable protections against stranded asset
8 risk and the Commission's future determination of the proper ratemaking treatment of any
9 stranded assets that may ultimately occur. The Commission can and should evaluate today
10 whether the proposed contractual arrangements reasonably demonstrate that reasonable
11 protections exist against potential stranded asset risk. That prospective review is both
12 appropriate and consistent with the Large Load Guidelines. The proper ratemaking
13 treatment of any future stranded assets, however, necessarily presents a different question.
14 That determination not only should not, but cannot, reasonably be made prospectively
15 because it necessarily depends on facts and circumstances that do not yet exist.

16 Accordingly, while the Large Load Guidelines appropriately require applicants to
17 demonstrate that reasonable protections exist against stranded asset risk, the proper
18 ratemaking treatment of any stranded assets or associated costs cannot reasonably be
19 predetermined in this proceeding. Should such circumstances arise in the future, the
20 Commission should evaluate the appropriate treatment based on the facts and
21 circumstances then existing, including, but not limited to, the cause of the stranded asset,
22 the prudence of the utility's actions, the effectiveness and enforcement of contractual
23 protections, liquidation efforts, guaranty recoveries, replacement uses of the assets, market

1 and salvage value, benefits previously received by customers, remaining useful life, and
2 any other factors relevant to determining just and reasonable rates.

3 **b. EARLY TERMINATION**

4 **Q112. BEFORE DISCUSSING THE SPECIFIC FINANCIAL PROTECTIONS**
5 **INCLUDED IN THE CUSTOMER AGREEMENTS, PLEASE PROVIDE AN**
6 **OVERVIEW OF THE EARLY TERMINATION PROVISIONS.**

7 A. As discussed in the previous section, one of the Commission's Large Load Guidelines asks
8 whether there are reasonable protections against stranded generation, transmission, and
9 fuel infrastructure. ELL contends that it satisfies this objective related to a potential early
10 termination primarily through a comprehensive set of contractual provisions contained in
11 the CIAC Agreement and the ESA that are intended to allocate the financial consequences
12 of an early termination to the Customer rather than to ELL's existing customers.

13 Although the CIAC Agreement and the ESA govern distinct phases of the Project
14 and therefore contain different remedies, they are structured around the same fundamental
15 objective. During the pre-service commencement construction period governed primarily
16 by the CIAC Agreement, the Customer generally agrees to reimburse ELL for costs
17 associated with facilities constructed for Project Evest through what Ms. Beauchamp refers
18 to as the CIAC Liquidation Process. Under that process, ELL calculates the remaining
19 construction costs, credits the Customer for [REDACTED], and
20 requires the Customer to reimburse the remaining balance, including applicable Other
21 Unrecouped Costs (as defined below).¹²¹

¹²¹ Direct Testimony of Laura Beauchamp at 29.

1 Once service has commenced under the ESA, the contractual remedies shift to
2 reflect the fact that many of the facilities have entered service. As described by Ms.
3 Beauchamp, the ESA Liquidation Process generally provides ELL the option to retain
4 certain generators for continued system use while liquidating others. Depending on the
5 applicable termination event, the Customer generally becomes responsible for the
6 remaining net book value of applicable in-service assets, unrecovered construction costs
7 for assets not yet in service, Other Unrecouped Costs, [REDACTED], and
8 other payments required under the ESA.¹²²

9 These contractual objectives are summarized by Mr. Kidd, who states that, on an
10 early termination, the Company has structured the Customer Agreements so that it
11 recovers: (1) unrecovered costs of assets still under construction, (2) the net book value of
12 applicable in-service assets, and (3) the Company's Other Unrecouped Costs. Other
13 Unrecouped Costs include [REDACTED]

14 [REDACTED]

15 [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 [REDACTED]

19 [REDACTED]. Mr. Kidd

20 further explains that continued payment of MMCs during portions of the liquidation

¹²² *Id.* at 30-31.

1 process together with various termination and milestone payments provide additional
2 contractual protection against early termination risk.¹²³

3 Standing alone, these contractual provisions appear thoughtfully designed and, if
4 fully performed, would provide substantial protection against the financial consequences
5 of an early termination.

6 **Q113. ARE THE CUSTOMER'S CONTRACTUAL OBLIGATIONS, STANDING**
7 **ALONE, SUFFICIENT TO PROTECT ELL AND ITS CUSTOMERS AGAINST**
8 **EARLY TERMINATION RISK?**

9 A. Not necessarily. A contractual obligation to make a payment and the financial ability to
10 satisfy that obligation are two different concepts. From a credit perspective, a contractual
11 promise has value only to the extent the obligor possesses the financial resources necessary
12 to perform that promise. Accordingly, while the Customer Agreements establish what the
13 Customer is obligated to pay, it is equally important to evaluate what financial resources
14 stand behind those obligations.

15 ELL recognized this distinction in performing its credit analysis of Project Evest.
16 Company witness Kenroy Hinkson explains that ELL began by evaluating the Customer
17 itself. Because Evest did not possess a standalone credit rating prior to execution of the
18 Customer Agreements, ELL did not credit the Customer with any value for purposes of its
19 credit analysis. [REDACTED]

20 [REDACTED]

¹²³ Direct Testimony of Thomas Kidd at 10-11.

1 [REDACTED]
2 [REDACTED].¹²⁴

3 Instead, the Customer's contractual obligations are supported through a separate
4 package of financial assurances consisting principally of the Evest Guaranty, [REDACTED]
5 [REDACTED], and Credit Default Security. These financial protections are intended to stand
6 behind the Customer's contractual obligations in the event the Customer is unable or
7 unwilling to satisfy them directly.¹²⁵

8 Accordingly, the adequacy of ELL's proposed early termination protections
9 depends on two separate inquiries. First, whether the Customer Agreements appropriately
10 define the Customer's contractual obligations. Second, whether the proposed package of
11 financial assurances has been reasonably structured and appropriately sized to support
12 those obligations. The remainder of this section evaluates each of those financial
13 protections.

14 **Q114. HOW DID ELL STRUCTURE THE FINANCIAL ASSURANCE PACKAGE TO**
15 **SUPPORT THE CUSTOMER'S CONTRACTUAL OBLIGATIONS?**

16 A. ELL did not attempt to require a single financial instrument that automatically guarantees
17 payment of every contractual obligation that could arise under the Customer Agreements.
18 Instead, ELL developed a layered financial assurance structure intended to support the
19 Customer's contractual obligations through multiple complementary forms of protection.
20 As provided in Rider 1, Section 7(D) and Appendix E to the ESA, the principal elements
21 of the financial assurance structure consist of:

¹²⁴ Direct Testimony of Kenroy Hinkson at 11-14.

¹²⁵ *Id.*

- 1 • the Meta Guaranty;
- 2 • [REDACTED] and
- 3 • Credit Default Security.

4
5 Each of these protections serves a different purpose and addresses a different aspect of the
6 Company's financial exposure. Mr. Kidd explains that the Company required the Meta
7 Guaranty, [REDACTED], and Credit Default Security and that he was specifically tasked
8 with determining the appropriate size of each of those protections over the term of the
9 Customer Agreements as ELL's credit exposure changes over time.¹²⁶

10 Likewise, Mr. Hinkson explains that ELL required these protections because it
11 determined it could not rely on the Customer's standalone creditworthiness. Instead, ELL
12 required the Meta Guaranty, [REDACTED], and Credit Default Security as
13 separate credit enhancements supporting the Customer's contractual obligations.¹²⁷

14 ELL further explains that these protections are intended to operate together rather
15 than independently. Mr. Hinkson testifies that the Credit Default Security is designed to
16 be supplemental to and also to backstop the Meta Guaranty for the Company's overall
17 exposure to the Customer.¹²⁸ Likewise, Mr. Kidd concludes that, "[w]hen combined with
18 the Credit Default Security and other collateral support, these layered protections
19 collectively make recovery under the Meta Guaranty highly secure, even in the event of a
20 significant downgrade or default scenario".¹²⁹

¹²⁶ Direct Testimony of Thomas Kidd at 26.

¹²⁷ Direct Testimony of Kenroy Hinkson at 7.

¹²⁸ *Id.* at 13.

¹²⁹ Direct Testimony of Thomas Kidd at 31-32.

1 Accordingly, the adequacy of ELL's proposed early termination protections
2 depends not on any single financial assurance, but on the interaction of these various layers
3 of protection. The following sections discuss each of these financial protections
4 individually before evaluating how, collectively, they support the Customer's contractual
5 obligations.

6 **Q115. ARE THE CUSTOMER'S CONTRACTUAL OBLIGATIONS AND THE**
7 **FINANCIAL ASSURANCE PACKAGE IDENTICAL?**

8 A. No. Although the two are closely related, they serve different purposes and are structured
9 differently. The Customer Agreements define the Customer's contractual obligations in
10 the event of an early termination. As discussed previously, depending on the applicable
11 agreement and the circumstances giving rise to the termination, those obligations may
12 include unrecovered construction costs, the net book value of certain in-service assets,
13 Other Unrecouped Costs, [REDACTED], [REDACTED]
14 [REDACTED], and various other contractual payments. Those provisions establish
15 what the Customer is contractually obligated to pay.¹³⁰

16 The financial assurance package, however, is structured differently. Rather than
17 providing an uncapped guaranty of every contractual obligation that may arise under the
18 Customer Agreements, both the CIAC Agreement and the ESA require the Customer to
19 furnish specified forms of security, including the Meta Guaranty, Supplemental Security
20 (cash or letters of credit), and Credit Default Security, in amounts determined under
21 separate contractual provisions. The Guaranty itself is not expressed as "whatever the
22 Customer owes." Instead, it is established pursuant to a Guaranty Schedule, is subject to a

¹³⁰ Direct Testimony of Laura Beauchamp at 29-31.

1 Guaranty Cap, and may be adjusted in accordance with the procedures set forth in the
2 Customer Agreements.¹³¹

3 Likewise, the supplemental security requirements are not tied directly to the amount
4 of the Customer's contractual obligations. Instead, they are determined by reference to the
5 applicable amount then reflected on the Guaranty Schedule and the guarantor's credit
6 rating under the contractual Downgrade Matrix. If the guarantor's credit rating declines,
7 the Customer must provide additional cash or letters of credit equal to the applicable
8 percentage reduction in the value of the Guaranty multiplied by the then-current Guaranty
9 amount.¹³²

10 Accordingly, ELL did not attempt to match each potential contractual obligation
11 dollar-for-dollar with a corresponding financial instrument. Rather, it developed and sized
12 a collection of separate financial assurances that it contends, when considered collectively,
13 provide reasonable protection for the contractual obligations established under the
14 Customer Agreements. Whether those financial assurances have, in fact, been reasonably
15 structured and appropriately sized depends on the assumptions and methodology ELL
16 employed in developing the Guaranty Schedule, Supplemental Security requirements, and
17 Credit Default Security rather than simply on the contractual obligations themselves.

¹³¹ Exhibit LKB-3 (CIAC Agreement) at 34-35 of 160 (Section 5, "Security; Guaranty"); Exhibit LKB-2 (Rider 1 of the ESA) at 44-46 of 123 (Section 7(D), "Security").

¹³² Exhibit LKB-3 (CIAC Agreement) at 35 of 160; Exhibit LKB-2 (Rider 1 of the ESA) at 46 of 123.

1 **Q116. WHAT ARE THE PURPOSES AND RELATIVE STRENGTHS OF THE**
2 **INDIVIDUAL FORMS OF FINANCIAL ASSURANCE?**

3 A. As discussed above, ELL did not rely on the Customer's own creditworthiness because the
4 Customer did not possess a standalone credit rating. Instead, ELL concluded that the risks
5 associated with Project Evest should be addressed through a layered financial assurance
6 package consisting of a Meta Guaranty, [REDACTED], and Credit Default Security that
7 the Company describes as overlapping and complementary protections intended to mitigate
8 the risks to ELL and its other customers if the Customer fails to satisfy its contractual
9 payment obligations.¹³³

10 The first layer is the Meta Guaranty, which is intended to place a financially strong
11 entity behind the Customer's contractual obligations. Mr. Hinkson explains that the two
12 principal considerations in evaluating a guaranty are the size of the guaranty and the
13 creditworthiness of the guarantor. ELL evaluated Meta's publicly available financial
14 information and credit ratings and determined that Meta's current AA- rating from S&P
15 and Aa3 rating from Moody's signify strong investment-grade credit quality. Mr. Hinkson
16 states that S&P classifies AA- as a high-grade rating and that approximately 1% of
17 companies rated AA- by S&P defaulted within fifteen years during the period from 1981
18 through 2024.¹³⁴

19 ELL also recognized that Meta's credit quality could decline during the twenty-
20 year term of the ESA. The Customer Agreements therefore include a Downgrade Matrix
21 requiring [REDACTED] liquid collateral if and as Meta's credit rating declines. The collateral

¹³³ Direct Testimony of Kenroy Hinkson at 3, 6-7.

¹³⁴ *Id.* at 8.

1 requirement begins [REDACTED]
2 [REDACTED]. If Meta falls below [REDACTED], it must replace [REDACTED]
3 of the Meta Guaranty with cash or a letter of credit.¹³⁵ Thus, the principal strength of the
4 Meta Guaranty is Meta's present financial strength, while the Downgrade Matrix is
5 intended to preserve the value of the protection if that financial strength deteriorates.

6 The second layer is the [REDACTED]. [REDACTED]
7 [REDACTED]
8 [REDACTED]
9 [REDACTED]
10 [REDACTED]
11 [REDACTED] [REDACTED]
12 [REDACTED]
13 [REDACTED]
14 [REDACTED]
15 [REDACTED]
16 [REDACTED] [REDACTED]
17 [REDACTED]
18 [REDACTED].

19 The third layer is Credit Default Security. [REDACTED]
20 [REDACTED]

¹³⁵ *Id.* at 9-11.

¹³⁶ *Id.* at 12.

¹³⁷ *Id.* at 13.

1 [REDACTED] Mr. Hinkson explains that this protection is intended to supplement and
2 backstop the Meta Guaranty for the overall exposure associated with the Customer.¹³⁸

3 Credit insurance is one form of Credit Default Security contemplated by the
4 Customer Agreements. Under that form of protection, the insurer or other financial-
5 services provider agrees to pay ELL if Meta and/or the Customer fails to make a required
6 payment. If the Customer fails to pay, ELL may [REDACTED]
7 pursue the Meta Guaranty. If Meta then fails to satisfy its obligations under the Guaranty,
8 ELL may make a claim on the Credit Default Security. Mr. Hinkson explains that this
9 provides an additional, independent source of recovery, with the responsibility for
10 subsequently pursuing Meta or Evest shifting to the insurer.¹³⁹

11 Credit Default Security does not, however, eliminate all counterparty or
12 collectability risk. Mr. Hinkson states that the market for the bespoke coverage
13 contemplated here can presently support only approximately [REDACTED] of total exposure.
14 He also explains that ELL imposes minimum financial standards on letter-of-credit issuers,
15 Credit Default Security providers, and escrow agents. Among other requirements, a letter-
16 of-credit issuer must have at least an A- credit rating and \$10 billion of assets, and any
17 issuer of Credit Default Security must possess financial resources of a scale appropriate to
18 support its obligations.¹⁴⁰

19 Viewed together, the proposed package provides three complementary types of
20 protection: (1) The Meta Guaranty relies on Meta's financial strength to support the

¹³⁸ *Id.*

¹³⁹ *Id.* at 14-15.

¹⁴⁰ *Id.* at 15-16.

1 Customer's obligations; (2) [REDACTED]
2 [REDACTED] the Credit Default Security supplies an
3 additional and independent source of recovery if Meta fails to perform under the Guaranty.
4 The strengths of these instruments are not identical: one primarily provides credit support,
5 [REDACTED] and one transfers a portion of the default risk to an additional
6 financially qualified counterparty.

7 **Q117. DID ELL DEVELOP SEPARATE METHODOLOGIES FOR SIZING EACH OF**
8 **THE VARIOUS FORMS OF FINANCIAL ASSURANCE?**

9 A. Yes. Based on my review of the information provided by ELL, ELL did not simply select
10 arbitrary dollar amounts for the various forms of financial assurance. Rather, ELL
11 developed separate methodologies for sizing each component of the financial assurance
12 package based on the distinct risks that each instrument was intended to address.¹⁴¹

13 As an initial matter, Mr. Kidd explains that he was specifically tasked with
14 recommending the size of the Meta Guaranty, [REDACTED] and the size
15 of the Credit Default Security over the term of the Customer Agreements as ELL's credit
16 needs fluctuate.¹⁴² Mr. Kidd further explains that the Company developed a financial
17 model, included as Exhibit TK-1, that assessed ELL's financial condition and its ability to
18 fund the investments required by the Customer Agreements while maintaining its financial
19 health. The model analyzed cash flows, costs, revenues, return on equity, credit metrics,
20 and the amount of cash-flow and credit support needed from the Customer to manage

¹⁴¹ Direct Testimony of Thomas Kidd at 26-29.

¹⁴² *Id.* at 26.

1 ELL's overall cash flow and debt. Mr. Kidd used those outputs to advise management
2 regarding the provisions ultimately incorporated into the Customer Agreements.¹⁴³

3 Mr. Kidd also explains that ELL's financial exposure is not static. As the Original
4 Term of the ESA progresses, the MMCs recover depreciation on the Proposed Generators
5 and other investments required to serve Project Evest. This reduces the assets' net book
6 value, the amount of the Customer's termination obligation, and ELL's corresponding
7 exposure. Mr. Kidd also states that ELL expects it would likely retain the three CCCTs
8 proposed for the Big Cajun site if an early termination occurred, which would further
9 reduce ELL's exposure. Consequently, the required size of the Meta Guaranty can
10 fluctuate over time and generally diminishes as the assets are depreciated.¹⁴⁴

11 Consistent with those differing and changing risks, ELL developed separate sizing
12 methodologies for each form of financial assurance. The CIAC Guaranty was sized by
13 reference to ELL's construction spending and certain Other Unrecouped Costs [REDACTED]
14 [REDACTED]¹⁴⁵ ELL used this analysis to develop a
15 Guaranty schedule presented in CIAC Exhibit I-2 with three stepped up amounts of
16 Guaranty to cover the CIAC Risk.

17 The ESA Guaranty was sized using a separate formula that considers the
18 unrecovered cost of the Proposed Generators, [REDACTED], certain
19 Other Unrecouped Costs, estimated residual value, deferred revenues, excess CIAC
20 contributions, [REDACTED] projected MMCs, and the anticipated retention of

¹⁴³ *Id.* at 13; Exhibit TK-1.

¹⁴⁴ *Id.* at 26-28.

¹⁴⁵ *Id.* at 27.

1 the Pointe Coupee units.¹⁴⁶ ELL used this analysis to develop a Guaranty Schedule
2 consisting of annual required guaranty amounts, subject to a [REDACTED] cap, that increase
3 during the years in which the Proposed Generators are being constructed and placed into
4 service, and thereafter decline as ELL's modeled exposure decreases due to declining net
5 book values and ELL's assumption that the three Pointe Coupee units are removed from
6 the guaranty calculation after Years 5, 7, and 9. These annual Guaranty amounts are
7 presented in Appendix E to Rider 1 of the ESA.

8 [REDACTED]
9 [REDACTED]
10 [REDACTED] [REDACTED]
11 [REDACTED]
12 [REDACTED]
13 [REDACTED]

14 The Credit Default Security was sized by targeting approximately [REDACTED] of ELL's
15 projected exposure to the Customer, subject to the approximately [REDACTED] capacity
16 limitation of the available market.¹⁴⁸ These amounts are also reflected annually in
17 Appendix E to Rider 1 and decline over time as ELL's projected exposure declines.

18 Accordingly, rather than attempting to establish a single financial assurance amount
19 applicable to every circumstance, ELL developed separate methodologies for the CIAC

¹⁴⁶ *Id.* at 27-28.

¹⁴⁷ *Id.* at 28-29.

¹⁴⁸ *Id.* at 29.

1 Guaranty, the ESA Guaranty [REDACTED] and the Credit Default Security. The
2 following questions discuss each of those methodologies individually.

3 **Q118. IS THE SIZE OF THE ESA GUARANTY FIXED FOR THE TERM OF THE**
4 **AGREEMENTS?**

5 A. No. [REDACTED]
6 [REDACTED]
7 [REDACTED]
8 [REDACTED]
9 [REDACTED]
10 [REDACTED]
11 [REDACTED]
12 [REDACTED]
13 [REDACTED]
14 [REDACTED]

15 In my opinion, the inclusion of such a provision is understandable. The Original
16 Term of the ESA extends for twenty years, during which time the Company's exposure
17 will naturally evolve as assets are placed into service, depreciated, retired, retained, or
18 potentially sold. Likewise, assumptions regarding asset values, customer obligations, and
19 the Company's financial exposure may differ materially from those existing when the
20 agreements were negotiated. It would therefore be impractical to assume that a single
21 Guaranty Schedule established today will necessarily remain appropriate throughout the
22 entire term of the ESA. This provision also addresses one of the concerns raised in Docket
23 No. U-37425 regarding the Meta Guaranty, namely, that the Guaranty Schedule might not

1 adequately reflect ELL's exposure if the final cost of the Proposed Generators materially
2 exceeded the estimated construction costs used in developing the original Guaranty
3 Schedule. Although the agreements do not mandate any particular adjustment, I expect
4 that a material increase in the Company's projected exposure resulting from significantly
5 higher construction costs would be the type of circumstance that would appropriately
6 trigger the parties' consideration of an updated Guaranty Schedule under this provision.

7 I believe it was reasonable for ELL to recognize that the appropriate amount of the
8 ESA Guaranty may change over the life of the Project, and accordingly, the Commission
9 should not view the initial Guaranty Schedule as permanently establishing the appropriate
10 amount of financial assurance for the duration of the Customer Agreements. Rather, the
11 adequacy of the ESA Guaranty will ultimately depend not only on the reasonableness of
12 ELL's initial assumptions, but also on how this adjustment mechanism is implemented
13 over time as the Company's actual financial exposure evolves.

14 **Q119. WHAT IS YOUR OVERALL EVALUATION OF ELL'S PROPOSED EARLY**
15 **TERMINATION PROTECTIONS?**

16 A. Overall, I believe ELL has devoted substantial effort toward addressing the financial risks
17 associated with the early termination of the Customer Agreements. Rather than relying on
18 a single form of protection, ELL developed a comprehensive framework consisting of
19 contractual payment obligations, a Meta Guaranty, [REDACTED] and Credit Default
20 Security, each designed to address distinct aspects of the Company's financial exposure.
21 ELL also developed separate methodologies for sizing each of those protections and
22 recognized that its exposure would evolve over the twenty-year term of the Customer
23 Agreements.

1 In my opinion, these provisions demonstrate that ELL has made a good-faith effort
2 to protect against the risk that a premature termination of Project Evest could result in
3 significant stranded investment or other unrecovered costs. I believe the information
4 provided by ELL reflects a serious attempt to identify the principal financial risks
5 associated with this unprecedented project and to develop contractual mechanisms
6 intended to mitigate those risks.

7 At the same time, these protections necessarily rest on assumptions regarding future
8 construction costs, future asset values, future customer obligations, future market
9 conditions, and the future implementation of the contractual provisions themselves.
10 Whether those assumptions ultimately prove accurate cannot be known today. Likewise,
11 the effectiveness of the financial assurance package cannot be fully evaluated until it is
12 tested against actual events, should an early termination ever occur.

13 Accordingly, while I believe the information provided by ELL demonstrates that
14 ELL has made a good-faith effort to address the financial risks associated with an early
15 termination, and that this effort is sufficient to satisfy the intent of the Commission's Large
16 Load Guidelines requiring the Company to reasonably protect its existing customers
17 against the risk of stranded investment, I do not believe this proceeding should
18 predetermine the ultimate adequacy of those protections or the ratemaking treatment of any
19 future stranded costs. If the Commission certifies the requested resources, the Commission
20 should make clear that it retains its full authority to evaluate the actual facts that exist if
21 and when an early termination were to occur, including but not limited to, the parties'
22 performance under the Customer Agreements, the effectiveness of the financial assurances,

1 and any request for stranded cost recovery based on the information provided by ELL
2 developed at that time.

3 c. NON-RENEWAL

4 **Q120. HOW DO YOU EVALUATE THE STRANDED ASSET RISK ASSOCIATED**
5 **WITH THE EXPIRATION OR NON-RENEWAL OF THE CUSTOMER**
6 **AGREEMENTS?**

7 A. In my opinion, the non-renewal scenario presents a different type of stranded asset analysis
8 than an early termination. In the early termination scenario, the principal question is
9 whether ELL has developed adequate contractual and financial protections to mitigate the
10 risk that existing customers would be required to absorb investments made specifically to
11 serve Project Evest on expiration of the Original Term of the Customer Agreements,
12 however, those contractual protections largely have served their intended purpose. The
13 remaining question becomes whether the benefits received by customers during the twenty-
14 year term are sufficient to justify any remaining investment in the assets after the Customer
15 Agreements expire.

16 The information provided by ELL demonstrates that ELL has taken several
17 meaningful steps to reduce that potential exposure. Most notably, ELL proposes to
18 depreciate the four Richland Combined Cycle Combustion Turbines over a twenty-year
19 service life rather than a longer traditional depreciation period.¹⁴⁹ As discussed earlier in
20 my testimony, those accelerated depreciation costs are incorporated into the MMC and are
21 therefore recovered from the Customer over the term of the Customer Agreements rather

¹⁴⁹ Direct Testimony of Ryan Jones at 15–16.

1 than being deferred to existing customers following expiration of the ESA.¹⁵⁰ In addition,
2 because the MMC is subject to periodic true-up, material increases in the actual
3 construction costs of those facilities will likewise be reflected in the revenues collected
4 from the Customer rather than remaining unrecovered during the contract term.

5 Another asset requiring consideration is the proposed West Fork Creek–St. Landry
6 500-kV transmission line. Unlike the Richland generating facilities, this transmission
7 investment is expected to have a substantial remaining service life on expiration of the
8 Original Term of the Customer Agreements. Nevertheless, the information provided by
9 ELL demonstrates that this facility is expected to provide benefits extending well beyond
10 serving Project Evest, including improvements in system reliability and resilience,
11 increased transmission capability, and the ability to facilitate future generation
12 interconnections.¹⁵¹ While those broader system benefits do not eliminate the possibility
13 of remaining investment following expiration of the ESA, they do distinguish this
14 transmission facility from assets that solely benefit a single customer.

15 Ultimately, however, these individual mitigation measures are not, standing alone,
16 the primary basis for my conclusion under Large Load Guideline #4. Rather, my
17 conclusion is driven principally by the economic benefits expected to be realized by
18 existing customers during the twenty-year term of the Customer Agreements. As discussed
19 below in Section IV.D., my independent review of ELL’s economic analyses, including a
20 sensitivity assuming recovery of only the MMCs, confirms that it demonstrates that
21 existing customers are expected to receive significant net economic benefits over the term

¹⁵⁰ RLS-011 (ELL response to Sierra 1-9).

¹⁵¹ Direct Testimony of Daniel Kline at 21-24.

1 of the ESA. When those benefits are considered together with the contractual protections,
2 accelerated depreciation, ongoing prudence review, and the anticipated long-term value of
3 the proposed transmission investments, I conclude that ELL has reasonably addressed the
4 stranded asset risk associated with the non-renewal scenario and has satisfied the intent of
5 the Commission's Large Load Guidelines.

6 **Q121. DO YOU HAVE ANY RECOMMENDATIONS THAT COULD FURTHER**
7 **REDUCE THE POTENTIAL STRANDED ASSET RISK ASSOCIATED WITH A**
8 **NON-RENEWAL OF THE CUSTOMER AGREEMENTS?**

9 A. Yes. Although I conclude that the intent of the Commission's Large Load Guidelines is
10 adequately addressed with respect to the non-renewal scenario, the Commission should
11 require ELL, to file a comprehensive transition plan on receiving a notice of non-renewal
12 from the Customer addressing the disposition of any generation or transmission assets that
13 may remain following expiration of the Customer Agreements. In my opinion, such a filing
14 should be made within six months after receiving notice of non-renewal. The purpose of
15 the filing would not be to predetermine ratemaking treatment, but rather to provide the
16 Commission with sufficient time to evaluate alternatives for minimizing any remaining
17 stranded investment before the Customer Agreements expire.

18 At a minimum, I believe the transition plan should identify how ELL proposes to
19 utilize or monetize the remaining generation assets. This could include, among other
20 alternatives, incorporating the facilities into ELL's resource portfolio if they continue to be
21 needed to serve native load, marketing the output under one or more power purchase
22 agreements, selling the facilities, or pursuing any other commercially reasonable

1 alternative that minimizes the amount of investment ultimately borne by existing
2 customers.

3 To the extent ELL proposes to continue recovering the costs of any assets that
4 remain neither used nor useful following expiration of the Customer Agreements, I believe
5 ELL should be required to demonstrate why continued recovery is reasonable under the
6 facts then existing. Such a showing could include an evaluation of the actual economic
7 benefits that Project Evest provided to existing customers during the twenty-year term of
8 the Customer Agreements, the remaining value and expected future usefulness of the
9 assets, and any other factors supporting continued recovery.

10 Finally, I believe the transition plan should include any ratemaking proposals ELL
11 believes would mitigate substantial customer rate impacts associated with any remaining
12 stranded investment. Depending on the circumstances existing at that time, such proposals
13 could include deferred recovery or other regulatory mechanisms designed to moderate
14 customer impacts while allowing the Commission to evaluate the appropriate ratemaking
15 treatment based on a complete evidentiary record.

16 This recommendation is not intended to predetermine the Commission's ultimate
17 ratemaking decision. Rather, it is intended to ensure that, should a non-renewal occur, the
18 Commission is presented with a comprehensive plan that first seeks to maximize the
19 continued value of the assets and minimize any remaining stranded investment before
20 determining what, if any, and how costs should ultimately be recovered from customers.

12. LARGE LOAD GUIDELINE #12: ONGOING OVERSIGHT

Q122. WHAT DOES THE COMMISSION'S TWELFTH LARGE LOAD GUIDELINE ADDRESS?

A. Large Load Guideline #12 addresses the Commission's need for ongoing oversight of approved large load projects. Specifically, the Large Load Guideline provides that the utility should propose ongoing reporting requirements sufficient to allow the Commission to monitor the project's implementation and performance throughout the term of the Customer Agreements. Those reports should include, at a minimum, the status of contractual obligations and project milestones, actual customer load compared to projected load, the status of generation and transmission resources being developed to serve the customer, and the Company's cost recovery performance. The objective of the Large Load Guideline is to ensure the Commission receives timely information necessary to monitor the project, evaluate whether it continues to perform as anticipated, and identify any emerging issues that may warrant further regulatory review.

Q123. HAVE YOU EVALUATED ELL'S COMPLIANCE WITH LARGE LOAD GUIDELINE #12?

A. Evaluation of ELL's proposed ongoing reporting requirements and compliance with Large Load Guideline #12 has been handled by Staff Witness John A. Chapman. Accordingly, I defer to Mr. Chapman's testimony and recommendations regarding whether ELL's proposed reporting requirements provide the Commission with sufficient ongoing oversight of Project Evest.

D. REVIEW OF ELL'S PROPOSED TCI

**Q124. HAS ELL PROVIDED AN ANALYSIS OF THE ECONOMIC IMPACT THAT THE
EVEST PROPOSAL WILL HAVE ON ITS OTHER RATEPAYERS?**

A. Yes. Mr. Datta presents an economic analysis to address “the costs and benefits to other ELL customer of the generation and transmission resources needed to serve Project Evest, net of the Customer’s contributions of the costs of those resources during the initial 20-year term of the Customer’s electric service agreement.”¹⁵² The final output of this analysis is a TCI metric which is intended to show the total impact to ELL’s other ratepayers as a result of serving the new Evest load. Mr. Datta calculates a positive Total TCI of \$3.94 billion nominally and \$1.96 billion on an NPV basis.¹⁵³ He goes on to evaluate a “non-renewal” scenario, which is intended to reflect the economic result if Meta were to discontinue taking service from ELL under the Evest ESA at the end of its term in 2048. The TCI calculated in this metric was a positive \$986 million, leading Mr. Datta to conclude that “even in this conservative scenario, ELL’s other customers are expected to benefit substantially from the Customer’s Project.”¹⁵⁴

¹⁵² Direct Testimony of Samrat Datta at 3; *see also* Exhibit SD-2.

¹⁵³ The TCI figure referenced here and throughout my testimony (\$1,962,633,030) is the final TCI reflected in the analysis files that I have reviewed, which support Mr. Datta’s testimony. Mr. Datta’s errata Direct Testimony reports this figure as approximately \$1,968 million. *See* Errata Direct Testimony of Samrat Datta at 28 & Table 1 (\$1,967,929,242). The approximately \$5 million difference does not reflect any difference in the costs or benefits included in the analysis; total costs are identical, and the annual benefit and cost streams are the same. The difference lies in an NPV calculation in one line of the analysis and does not bear on the outcome.

¹⁵⁴ *Id.* at 30-32.

1 **Q125. WAS A SIMILAR ANALYSIS PRESENTED BY ELL IN DOCKET NO. U-37425**
2 **WHEN IT SOUGHT CERTIFICATION OF GENERATION NECESSARY TO**
3 **SERVE META'S LAIDLEY LOAD?**

4 A. Yes. In Docket No. U-37425 (the "Laidley Proceeding"), Mr. Datta provided a similar
5 economic analysis, and I responded to that analysis in my Direct Testimony in that docket,
6 raising certain concerns. Specifically, I took issue with the pricing and quantity
7 assumptions that ELL used for purchased capacity, the understatement of the Laidley
8 load's effect on ELL's overall transmission cost of service, and the timing of the Laidley
9 revenues utilized in that analysis.

10 Beyond those specific concerns, several features of ELL's assessment in that docket
11 bear on my review here. First, I observed that ELL's conclusion – that its other ratepayers
12 would remain whole even if the Laidley load discontinued service at the end of the contract
13 term – rested substantially on the residual value of the generators ELL proposed to
14 construct to serve that load. Second, I identified that ELL's assessment did not capture the
15 effect that Laidley would have on the fuel costs recovered through ELL's Fuel Adjustment
16 Clause ("FAC"), even though Laidley's expected fuel revenue represented more than half
17 of its total expected revenue. In the Laidley Proceeding, Mr. Datta characterized that
18 exclusion as intentional and conservative, and to assess that characterization I developed
19 an independent estimate of the variable supply cost effect using an implied FAC heat rate.
20 Third, I noted that ELL's minimum bill and associated revenue deferral proposal in that
21 docket did not fully account for the cost of the Mt. Olive to Sarepta transmission line – a
22 facility necessary to serve the Laidley load – such that ratepayers could be exposed to that
23 cost depending on Meta's operations and ELL's treatment of deferred revenue. Finally,

1 because the outcome of the assessment was sensitive to these and other assumptions, I did
2 not rely on the single termination scenario ELL presented. Instead, working from ELL's
3 assumptions, I modeled three scenarios that bracketed the plausible range of outcomes:
4 (1) ELL's end-of-term termination case, adjusted for the concerns above; (2) a minimum-
5 bill-only case in which Laidley takes service at a level insufficient to drive revenue beyond
6 the ESA's minimum charges; and (3) a case in which Laidley continues taking service for
7 the full commercial life of the generators.

8 **Q126. HAVE YOUR CONCERNS WITH THE ECONOMIC ANALYSIS FROM THE**
9 **LAIDLEY PROCEEDING BEEN ADDRESSED BY ELL IN THIS PROCEEDING?**

10 A. Largely, yes. First, ELL priced the incremental generation resources needed to serve the
11 Customer at the projected cost of owned and purchased generation with readily identifiable
12 and traceable costs, rather than relying on generic purchased-capacity pricing and quantity
13 assumptions I questioned in the Laidley Proceeding. Second, ELL incorporated the
14 deferred Customer revenue stream into its economic analysis, so that the revenues reflected
15 in the assessment correspond to the revenues that will actually be realized in rates rather
16 than as-billed amounts. Third, ELL's assessment now captures the effect of the Evest load
17 on the variable supply costs recovered through the FAC which, consistent with my prior
18 testimony, operates to increase the net benefit to ELL's other customers. ELL, however,
19 failed to account for the concerns I raised about the shift in Open Access Transmission
20 Tariff ("OATT") revenue resulting from the new Customer's load.

21 **Q127. WHAT IS THE CONCERN REGARDING THE SHIFT IN OATT REVENUE?**

22 A. As I will discuss in more detail below, ELL's analysis appropriately accounts for the cost
23 of the significant transmission investment required to serve the Customer. Mr. Datta's

1 assessment reflects the revenue requirement of the ELL-Funded Transmission Projects
2 necessary to serve the Evest load. ELL correctly reflected that its retail customers will bear
3 only a portion of that transmission revenue requirement (here, approximately 87%) because
4 the remaining approximately 13% is allocated under the MISO OATT to ELL's wholesale
5 transmission customers. That is a proper adjustment.

6 ELL's analysis, however, again recognizes only one side of the OATT effect.
7 While it credits the benefit that ELL's retail customers bear less than the full transmission
8 revenue requirement, it does not account for the offsetting effect that the Customer's load
9 has on that same tariff. The MISO OATT transmission rate is derived by dividing ELL's
10 transmission revenue requirement by a demand-based billing determinant. When the
11 Customer's exceptionally large load is added to that billing determinant, the denominator
12 increases and the per-unit transmission rate declines. That lower rate reduces the revenue
13 ELL collects from its wholesale transmission customers – revenue that, all else equal,
14 offsets the transmission costs otherwise borne by ELL's retail customers. This is the same
15 effect I identified in the Laidley Proceeding, where I estimated it at approximately \$21
16 million per year. Because the Evest load is substantially larger, the effect here is
17 correspondingly greater. It grows as the Customer's load ramps and, once fully ramped,
18 ranges from roughly \$20 million to approximately \$28.5 million per year, for a total of
19 approximately \$197 million on a net present value basis.

20 This remains a real cost of extending service to the Customer, and it should be
21 reflected in the economic assessment. When I incorporate it into Mr. Datta's analysis, the
22 net benefit to ELL's other customers is reduced by approximately \$197 million on an NPV
23 basis leaving a net benefit of approximately \$1.77 billion. Importantly, even after

1 accounting for this omitted OATT-revenue effect, the analysis continues to show a
2 substantial net benefit to ELL's other customers from the extension of service to Evest.

3 **Q128. ARE THERE ANY OTHER SIGNIFICANT DIFFERENCES BETWEEN THE**
4 **LAIDLEY AND EVEST ECONOMIC ANALYSES THAT ARE WORTH**
5 **MENTIONING?**

6 A. Yes. Just the sheer magnitude of the revenues and costs are different. For Laidley, ELL
7 was projecting approximately [REDACTED] in base non-fuel revenue under the customer's
8 fifteen-year ESA. Here, the Company is projecting over [REDACTED] in base non-fuel
9 revenue under the customer's twenty-year ESA.¹⁵⁵ I recognize that the application in this
10 proceeding presents a customer load requirement approximately [REDACTED] larger than was
11 needed to serve the Laidley load. But nevertheless, this significant increase in customer
12 revenue leads to many of the differences I have seen between the analysis submitted in the
13 Laidley Proceeding and the economic analysis submitted in this case.

14 **Q129. YOU SAID THAT ELL HAS ADDRESSED ONE OF YOUR PRIOR PRIMARY**
15 **CONCERNS REGARDING THE PRICING AND QUANTITY ASSUMPTIONS**
16 **FOR PURCHASED CAPACITY. PLEASE EXPLAIN FURTHER.**

17 A. One of my concerns in the Laidley Proceeding was with the purchased power assumptions
18 that ELL had utilized to meet the electrical demand of the Laidley load. There, ELL
19 presented a case where the generation it was seeking to designate costs to Laidley in the
20 certification only met a portion of the Laidley load needs. To bridge the difference, ELL
21 assumed a purchase of generating capacity to serve the customer's supply needs that

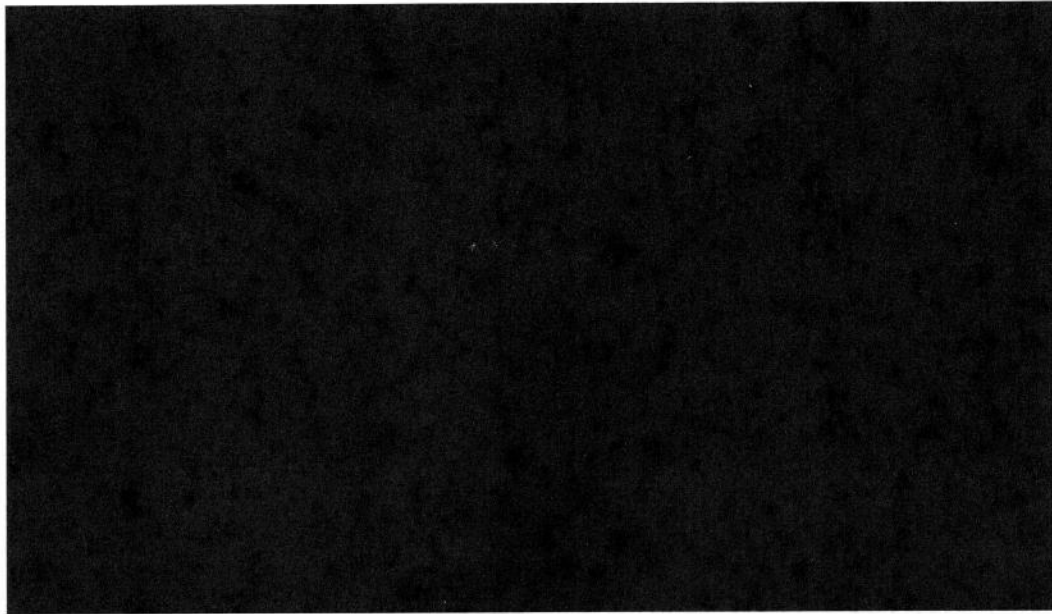
¹⁵⁵ Direct Testimony of Ryan Jones at 19.

1 exceeded the output of the three generators that were being built to serve the load. I took
2 issue with both the pricing and the size of the need, ultimately concluding that ELL would
3 have a continuing prudence obligation to ensure that the remainder of the supply need was
4 met – and importantly, that the customer’s ESA would be amended to address the actual
5 price of the generation procured, whether that be more or less than the assumed price of
6 [REDACTED] used in my analysis of the Laidley load Application. All of these concerns
7 stemmed from ELL not presenting a full supply plan to serve the Laidley load.

8 In this Application, ELL has taken a different approach. Here, ELL has presented
9 a full supply plan with identifiable resources costs directly assigned to Evest and costs that
10 can be tracked. Once fully ramped, the generators that ELL has assigned in this filing, and
11 included within the Customer’s MMC, very closely match the total supply needs of the
12 customer.¹⁵⁶ [REDACTED] below, for example, shows the Evest load position when
13 compared to the generators ELL has assigned to serve that load:

¹⁵⁶ While ELL has provided a full supply plan, there is no specific plan for replacement if one of the certified assets is not placed into service. If that occurs ELL and the Customer must agree on a replacement that will need Commission certification.

1



2

3

4 **Q130. WAS THERE ALSO A CONCERN REGARDING THE DEPRECIABLE LIFE OF**
5 **THE GENERATION BEING BUILT TO SERVE THE LAIDLEY LOAD?**

6 A. Yes. One of the major issues in the Laidley Proceeding became the difference between the
7 life of the generators and the term of the customer's ESA. The generators had an assumed
8 depreciable life of 30 years while the term of the ESA was only 15 years. As a result, if
9 the Customer were not to renew its ESA, the generators built to serve the load would still
10 have a net book balance. And, this net book balance, if left in ELL's rate base, would have
11 to be paid for by ELL's other customers. This led to a significant issue in the Laidley
12 Proceeding – the residual value of the generators.

13 **Q131. HOW HAS ELL ADDRESSED THAT RESIDUAL GENERATION VALUE ISSUE**
14 **IN THIS EVEST APPLICATION?**

15 A. In two ways. First, the transaction structurally leaves less residual value behind in the first
16 place. The Customer's ESA runs for 20 years, rather than the 15-year term of the Laidley
17 ESA, and four of the CCCTs proposed for construction are correspondingly proposed to

1 have a depreciation life of 20 years. So, a greater share of the generators' cost is recovered
2 from the Customer over the life of the contract, and a correspondingly smaller
3 undepreciated balance remains at the end of the term. Then, ELL's assessment addresses
4 the residual value that does remain head-on by presenting two explicit scenarios side by
5 side.

6 In the first scenario it modeled, ELL assumes that the Proposed Generators, Battery
7 Storage Facilities, and ELL-Funded Transmission constructed to serve the Customer has
8 no stranded cost that must be borne by ELL's remaining customers. This could occur due
9 to a variety of circumstances, including (i) continuation of the service agreement with Evest
10 for the Evest load or (ii) utilization or liquidation of the generators (and other assigned
11 assets) at a value that meets or exceeds the net book value of the generators at the end of
12 the ESA. Either way, in that scenario, no undepreciated book value is stranded, and ELL's
13 other customers are assumed to realize the full TCI of approximately \$1.96 billion on an
14 NPV basis. Under this scenario other customers are not called on to absorb any residual
15 net book value of the assets constructed to serve the Evest load.

16 In the second scenario ELL modeled – the “non-renewal” scenario – the Customer
17 discontinues service at the end of the term in 2048, and ELL is left holding the
18 undepreciated net book value of the Proposed Generators, Battery Storage Facilities, and
19 ELL-Funded Transmission constructed to serve the Customer. That residual net book
20 value is approximately [REDACTED] as of 2048, or approximately \$976.6 million¹⁵⁷ on an
21 NPV basis. Significantly, in the non-renewal scenario, ELL's analysis assigns that entire
22 residual value to its other customers as a cost, without crediting any offsetting value ELL

¹⁵⁷ Direct Testimony of Samrat Datta at 32.

1 might realize from those assets through continued operation, resale, or service to other load.
2 In other words, the analysis treats the residual generation as a total loss to ratepayers. Even
3 under that deliberately conservative treatment, the TCI estimated by ELL remains positive
4 at approximately \$986 million on an NPV basis. And, with the adjustment I recommended
5 for OATT revenue, this benefit would be reduced to \$789 million.

6 Taken together, these features present a meaningful improvement over the analysis
7 presented in the Laidley Proceeding. As I explained, ELL's conclusion in the Laidley
8 Proceeding that ratepayers would remain whole rested substantially on the capture of the
9 speculative future residual value of the generators, a value I identified as a risk to the
10 modeled outcome and attempted to address accordingly. Here, the longer contract term
11 reduces the residual exposure at the outset, and the benefit to ratepayers does not depend
12 on realizing any residual value at all. ELL has quantified the net book value that would
13 remain and assigned it in full to ratepayers. And, the analysis demonstrates that ELL's
14 other customers still receive a substantial net benefit from the total impact of the Evest
15 load.

16 **Q132. YOU MENTIONED THAT ELL HAS PERFORMED A FULL ANALYSIS OF THE**
17 **FUEL IMPACTS. PLEASE EXPLAIN.**

18 A. That is correct. A full analysis of the impact of the Evest load must account for the impact
19 that this load will have on the energy markets in general and ELL's Fuel Adjustment Clause
20 ("FAC"). In the Laidley Proceeding, ELL excluded this effect from its economic
21 assessment altogether, asserting that the effect would be beneficial and that therefore its
22 analysis excluding the fuel effects was conservative. Nevertheless, in an attempt to
23 quantify the fuel impacts, I developed an independent estimate using an implied FAC heat

1 rate. In this proceeding, ELL has quantified the fuel impact directly through a full
2 production cost analysis.

3 Specifically, ELL used a production cost model to simulate the commitment and
4 dispatch of resources in the MISO wholesale energy market across the entire 20-year
5 Original Term of the ESA.¹⁵⁸ Through this modeling, ELL measured the change in ELL's
6 total variable supply cost between a Base Case, in which ELL neither serves the Evest load
7 nor builds the associated resources, and a Change Case, in which it does both. That change
8 captures both the added cost of serving the Customer's exceptionally large, high-load-
9 factor energy requirement and the offsetting effect of adding seven efficient combined-
10 cycle units and the battery resources to ELL's system. The net result is an estimated
11 reduction in the projected costs that ELL's customers would see in the Change Case (where
12 ELL is serving Evest) over the Base Case.

13 The reason this effect benefits ELL's other customers is a function of the efficiency
14 of the new generation. Because the proposed combined-cycle units have low operating
15 and fuel costs relative to the broader MISO market, a larger share of the revenue they earn
16 in that market represents a positive energy margin.. Those energy margins would be
17 credited back to ELL's customers through the FAC, reducing the variable costs that
18 customers would otherwise pay, and ELL's analysis models and estimates this effect.

19 The net result is a benefit to ELL's other customers. Over the Original Term, the
20 fuel and energy revenue attributable to the Customer (approximately [REDACTED] NPV)
21 exceeds the variable supply cost of serving the Customer's load (approximately [REDACTED])

¹⁵⁸ For its production cost modeling, ELL utilized EPIS, Inc.'s AURORA model, which is the same tool ELL uses for its MISO energy-market modeling and long-term variable-supply-cost planning.

1 [REDACTED] NPV) so that the Customer's fuel-related activity makes a net positive contribution
2 to the TCI rather than imposing a net cost. This is the same directional effect I identified
3 in the Laidley Proceeding, where I concluded that capturing the fuel effect would increase
4 the benefits to ratepayers. The difference is that here ELL has measured it directly and
5 completely through production cost modeling.

6 **Q133. YOU ALSO MENTIONED A CONCERN YOU RAISED IN THE LAIDLEY**
7 **PROCEEDING ABOUT A TRANSMISSION PROJECT NOT BEING COVERED**
8 **BY THE LAIDLEY LOAD. CAN YOU EXPLAIN FURTHER?**

9 A. Yes. In the Laidley Proceeding, ELL proposed to construct a new 500 kV transmission
10 line between Mt. Olive and Sarepta at a cost exceeding \$500 million. Once the Customer's
11 load was incorporated into MISO's transmission planning models, MISO classified the line
12 as a Baseline Reliability Plan project and ELL confirmed in discovery that there was no
13 immediate need for the line absent the Project.¹⁵⁹

14 My concern was with how the substantial cost of the Mt. Olive to Sarepta 500 kV
15 line was proposed to be treated under the Customer's ESA and the resulting effect that this
16 could have on ELL's other customers. There, ELL had modeled a scenario wherein the
17 Laidley load materialized as expected and that the revenue generated from this operation
18 would be sufficient to cover the cost of the Mt. Olive to Sarepta line and provide a net
19 benefit to customers. Because, the cost of the Mt. Olive to Sarepta line was not a
20 component of the minimum bill under the Laidley ESA, however, in the scenario where
21 the Customer was only paying that Laidley minimum charge, the cost of the Mt. Olive to
22 Sarepta line would fall more heavily on ELL's other customers. This drag on the overall

¹⁵⁹ LPSC Docket No. U-37425, Direct Testimony of R. Lane Sisung, at 96-98.

1 economics of the Laidley proposal was overcome in the minimum bill scenario through
2 other factors, but the result was a projection that customers would be roughly neutral in
3 that scenario, with no benefits resulting from the Laidley load.

4 **Q134. HAS ELL ADDRESSED THIS CONCERN?**

5 A. Yes. In this proceeding, ELL has accounted for the full cost of the transmission necessary
6 to serve the Customer, and it has done so in a way that is intended to ensure that no such
7 cost falls on other ratepayers other than the residual costs accounted for in the economic
8 analysis. As discussed in Section II above, the addition of the Evest load requires a defined
9 set of transmission upgrades, and Mr. Jones organizes those upgrades into two categories.
10 The first is the Customer-Funded Transmission Projects, which include the interconnection
11 facilities and the Smalling to El Dorado 500 kV line. Those projects are funded entirely
12 by the Customer through Contributions in Aid of Construction and therefore impose no
13 cost on ELL's other customers. The ELL-Funded Transmission Project, consisting of the
14 West Fork Creek to St. Landry 500 kV line and the new St. Landry switching station, are
15 at a combined cost of approximately \$1.462 billion. These projects will be placed in rate
16 base and recovered from customers, offset by revenue from the Customer and are
17 essentially the analog in this proceeding to the Mt. Olive to Sarepta line at issue in the
18 Laidley Proceeding.

19 Unlike in the Laidley Proceeding, however, the ELL-Funded Transmission Projects
20 in this docket are included in the MMCs under the Evest ESA. Therefore, even if the Evest
21 load does not materialize as expected, Meta will cover the costs of the ELL-Funded
22 Transmission Projects through the minimum bill provisions of the Evest ESA during the
23 term of the ESA. And, Mr. Datta included the full annual revenue requirement of the ELL-

1 Funded Transmission Project, for the entire duration of the ESA, directly in the economic
2 assessment that produces the TCI.¹⁶⁰ The amount of the customer-driven transmission
3 project costs that will be borne by ELL's other ratepayers is therefore no longer a function
4 of how the Evest load operates. This difference is reflected in the economic analysis and
5 the scenarios I discuss later.

6 **Q135. HAS ELL INCLUDED CERTAIN OTHER BENEFITS THAT IT DID NOT**
7 **REFLECT IN THE LAIDLEY ANALYSIS?**

8 A. Yes. ELL's economic analysis in this proceeding reflects the Customer's contributions to
9 The Power to Care program and to energy efficiency and weatherization programs as
10 quantified benefits in the TCI. These contributions were not reflected as direct benefits in
11 the Company's Laidley economic assessment.

12 Here, the Customer has committed to contribute \$3 million annually to The Power
13 to Care program, which provides bill assistance to older adults and customers with
14 disabilities living on low or fixed incomes in Louisiana, and the Company's shareholders
15 have committed to match that amount with an additional \$3 million annually – a combined
16 Power to Care contribution of \$6 million per year. The Customer has separately committed
17 to contribute \$7 million annually toward energy efficiency and weatherization programs.
18 Together, these commitments total \$13 million per year, or approximately \$260 million
19 over the 20-year Original Term of the ESA.¹⁶¹ Mr. Datta reflected these contributions in
20 the economic assessment, where they contribute approximately \$132 million to the TCI on
21 an NPV basis.

¹⁶⁰ Direct Testimony of Samrat Datta at 29.

¹⁶¹ Direct Testimony of Samrat Datta at 23-24.

1 This differs from the Laidley Proceeding in both scope and treatment. There, the
2 Customer's Power to Care commitment was a match of up to \$1 million per year and it
3 was addressed under the Corporate Sustainability Rider rather than counted as a benefit.
4 Moreover, there was no comparable dedicated energy efficiency commitment, and none of
5 it was carried into the economic assessment as a benefit to ELL's other customers. Here,
6 ELL has both expanded these commitments and reflected them directly in the analysis, so
7 that the value they provide to ELL's other customers is captured in the TCI.

8 **Q136. AS YOU NOTED, IN THE LAIDLEY PROCEEDING YOU PRESENTED A**
9 **SERIES OF SCENARIOS REFLECTING STAFF'S ANALYSIS OF THE**
10 **ECONOMIC BENEFITS. HAVE YOU DONE THE SAME HERE?**

11 A. Yes. As in the Laidley Proceeding, I did not rely on a single estimate of the net benefits or
12 costs of the Company's proposal. Instead, I evaluated three scenarios that cover the
13 plausible range of outcomes for ELL's other customers: (i) an expected case, which reflects
14 ELL's analysis with Staff's adjustment; (ii) a worst case, which tests what happens if the
15 Customer contributes only the minimum its ESA permits, taking only enough service to
16 stay at its MMCs for the entire term; and (iii) a best case, which reflects the Customer
17 continuing to take service across the full life of the generators. In every one of these
18 scenarios, ELL's other customers realize a substantial net benefit.

19 **Q137. PLEASE DESCRIBE THE FIRST, OR EXPECTED SCENARIO.**

20 A. The expected case is ELL's own economic analysis, corrected for the single adjustment I
21 described earlier – the omitted loss of OATT transmission revenue. It accepts the balance
22 of Mr. Datta's analysis, which I reviewed and found reasonable, and adds the
23 approximately \$197 million OATT cost that ELL did not reflect. The result is a TCI of

1 approximately \$1.77 billion on an NPV basis. And even in the corresponding non-renewal
2 case, the TCI remains a positive \$789.5 million.

3 **Q138. PLEASE DESCRIBE THE WORST CASE MODELED.**

4 A. The worst case that I modeled asks what happens if the Customer, rather than departing,
5 remains but contributes only the minimum its ESA allows, *i.e.* taking only enough service
6 to stay at its MMCs for the entire term. I made three changes to reflect that scenario, all of
7 which effect the revenue assumed from the Customer. First, I reduced the Customer's base
8 revenue to the MMCs under the ESA, reflecting a case wherein the customer is not
9 generating enough usage to exceed those MMCs. Second, I removed the Resilience Rider
10 revenue from the worst case modeled since the Resilience Rider does not assess charges
11 on minimum bills. Third, I adjusted the financed Storm Riders revenue to match the
12 scenario where the Customer is paying the MMCs, *i.e.* the Storm Rider revenues are
13 calculated applying its rates to the MMCs.

14 In this worst modeled case, I maintained the loss of OATT transmission revenue
15 that I had included as an adjustment to ELL's analysis. I recognize that because of the size
16 of the MMCs, the Customer could be generating a significant amount of demand on the
17 system, driving operational needs as well as the OATT effects I previously mentioned.
18 And, there are infinite scenarios in which the Customer is operating at a varying levels
19 below the level necessary to exceed a minimum bill, yet driving many of the impacts
20 reflected in ELL's analysis because of its demand at those varying levels. By maintaining
21 the full negative economic effect that the Customer's operations would have on ELL's
22 OATT revenue – and including that as if the Customer were taking full load – the worst

1 case I have modeled attempts to portray the largest negative economic impact to ELL's
2 customers related to the OATT.

3 Importantly, this scenario still credits the system benefits that a diminished
4 Customer would continue to have. It retains ELL's Capacity Benefit and Cost analysis in
5 full, thus assuming that ELL still must purchase capacity during the ramp years and still
6 has excess capacity to sell into the market in the later years. It likewise maintains the same
7 net fuel effect as was estimated if the Customer runs as expected. This is a conservative
8 assumption as any reduction in the Customer's energy use should benefit other ELL
9 customers because the generators would still provide additional energy margin without at
10 least some portion of the upward pressure that the Customer's energy use will have on the
11 marginal cost of energy. In other words, this scenario reflects a conservatively modeled
12 worst case: the Customer is assumed never to use enough service to exceed its minimum
13 bill, yet the system continues to bear the associated capacity dynamics. And, under those
14 assumptions, the TCI remains positive – \$1.46 billion on an NPV basis and \$479.9 million
15 in the corresponding non-renewal case.

16 **Q139. PLEASE DESCRIBE THE BEST CASE MODELED.**

17 A. The best case is the most straightforward of the three. In the Laidley Proceeding I
18 constructed a modeled continuation scenario, but here the point can be made directly
19 without the creation of a new model, because the residual value of the generators has
20 already been fully accounted for in the non-renewal analysis. Consider that Staff's analysis
21 indicates \$789.5 million in benefit in the expected case if the Customer terminates the ESA
22 at the end of its 20-year term. This assumes that the Customer departs in 2048 and ELL's
23 other customers absorb the entire residual cost of the assets supporting the Evest load. This

1 residual cost totals approximately [REDACTED]. In the best case modeled, the Customer
2 would continue taking service across the remaining commercial life of the generators,
3 which would extend at least ten years beyond the 20-year term.

4 Under that scenario, the residual cost is covered by the Customer's continuing
5 payments under ELL's retail rate schedule. As seen in the analysis, the Evest load is
6 expected to generate base revenue of approximately [REDACTED] per year during full
7 operation. As such, if Evest were to continue operating for 10 years beyond the term of its
8 current ESA it would produce approximately [REDACTED] in base revenue, more than
9 offsetting the [REDACTED] in the residual cost of the assets needed to serve it. I did not
10 model this scenario in the detail I applied to the other two, because its direction and
11 magnitude are not in doubt: continued service can only improve the outcome for ELL's
12 other customers.

13 **E. CONCLUSIONS AND RECOMMENDATIONS REGARDING THE**
14 **REQUESTED CERTIFICATIONS**

15 **Q140. BASED ON YOUR REVIEW OF THE INFORMATION PROVIDED BY ELL,**
16 **WHAT IS YOUR OVERALL RECOMMENDATION REGARDING ELL'S**
17 **REQUESTS FOR CERTIFICATION?**

18 A. Based on my review of the Application, the Customer Agreements, the testimony of the
19 Company witnesses, the discovery responses, and the analyses guided by the Large Load
20 Guidelines discussed throughout this testimony, I conclude that ELL has adequately
21 demonstrated that the Proposed Generators, Battery Storage Facilities, and Proposed
22 Transmission Projects are reasonably expected to serve the public convenience and
23 necessity and are in the public interest, provided the Commission imposes certain

1 conditions intended to preserve its continuing regulatory authority and to ensure that the
2 risks associated with Project Evest remain appropriately allocated.

3 Accordingly, I recommend that the Commission grant ELL's requested
4 certifications subject to the following conditions:

5 **1. Continuing Responsibility for the Customer Agreements.** The Commission's
6 certification should not constitute approval of the Customer Agreements or a determination
7 that those agreements adequately protect existing customers under every future
8 circumstance. ELL was responsible for negotiating and entering those agreements and
9 should remain responsible for them in all respects. ELL should remain fully responsible
10 for the prudence of negotiating, implementing, administering, and enforcing the Customer
11 Agreements, including the adequacy of the contractual protections and the allocation of
12 risks between ELL and the Customer. Nothing in the Commission's Order should limit
13 the Commission's authority in any future proceeding to evaluate those matters or to
14 determine the appropriate allocation of any resulting costs or damages. The Commission
15 retains its full authority to evaluate the actual facts that exist if and when an early
16 termination of the ESA or termination or modification of any Customer Agreement were
17 to occur, including but not limited to the parties' performance under the Customer
18 Agreements, the effectiveness of the financial assurances, and any request for stranded cost
19 recovery.

20 While the Commission is not approving the Customer Agreements, the
21 Commission's approval of the certification of the requested assets is subject to the
22 existence of the Customer Agreements as presented in ELL's Application, and those

1 Customer Agreements should not be substantially modified without express notification to
2 and express written consent of the Commission

3 **2. Continuing Responsibility for Project Implementation.** The certification
4 should be limited to the Proposed Generators, Battery Storage Facilities, and Proposed
5 Transmission Projects identified in this proceeding and should not be construed as approval
6 of future operational decisions, future modifications to the Customer Agreements, future
7 changes to the proposed supply plan, or implementation of the Customer's Ramp Schedule.
8 ELL should retain full responsibility for prudently managing Project Evest as changing
9 construction schedules, resource availability, system conditions, reliability requirements,
10 or other future circumstances may require, and any risks associated with those future
11 decisions should remain with ELL unless and until the Commission determines otherwise
12 in a future proceeding.

13 **3. Operational and Ratemaking Conditions Prior to Full Service.** Prior to the
14 commencement of full firm service, ELL should (a) submit for Commission review and
15 approval a comprehensive operational control and emergency load shed plan addressing
16 the integration of Project Evest into ELL's emergency operating procedures, and (b)
17 propose an appropriate ratemaking mechanism addressing any material capacity costs
18 incurred during the Customer's ramp period so that those costs are reasonably aligned with
19 the long-term benefits expected to be realized from Project Evest.

20 **4. Reservation of Future Ratemaking Authority.** Nothing in the Commission's
21 certification should be interpreted as predetermining the future ratemaking treatment of
22 any stranded assets, future changes to the proposed supply plan, future construction costs,
23 or any future request for recovery of costs associated with Project Evest. Those matters

1 necessarily include facts and circumstances that do not presently exist and should remain
2 subject to the Commission's continuing authority to determine the appropriate ratemaking
3 treatment if and when such issues arise.

4 **5. Existing Ratemaking Mechanisms and Rider Conformance.** Prior to the
5 Commission acting on this Application, ELL should identify any existing Commission-
6 approved riders, allocators, cost recovery mechanisms, or other rate design provisions that
7 are materially affected by the unique billing arrangements, deferred revenue treatment,
8 MMC structure, or the magnitude of the Customer's projected load under Project Evest,
9 and file one or more proposed solutions sufficient to ensure that such mechanisms continue
10 to operate in a manner consistent with their intended purpose, avoid over- or under-
11 collections, and equitably allocate costs and benefits among customer classes. The
12 Commission may, in its discretion, resolve such issues as part of this proceeding, condition
13 certification on implementation of an approved solution, or require ELL to present the
14 proposed modifications in one or more subsequent proceedings before the affected
15 mechanisms are implemented with respect to Project Evest.

16 **6. Renewal Reporting Requirements.** ELL should keep the Commission
17 informed about the renewal state of the ESA and related Customer Agreements, with
18 written notifications filed into this docket. ELL should file a comprehensive transition plan
19 on receiving a notice of non-renewal from the Customer addressing the disposition of any
20 generation or transmission assets that may remain following expiration of the Customer
21 Agreements. This filing should be made within six months after receiving notice of non-
22 renewal. The transition plan should identify how ELL proposes to utilize or monetize the
23 remaining generation assets. To the extent ELL proposes to continue recovering the costs

1 of any assets that remain neither used nor useful following expiration of the Customer
2 Agreements, ELL should demonstrate why continued recovery is reasonable under the
3 facts then existing. The transition plan should include ratemaking proposals to mitigate
4 customer rate impacts associated with any remaining stranded investment.

5 Subject to the recommendations discussed throughout my testimony, and as
6 summarized above, I conclude that ELL has demonstrated that the Proposed Generators,
7 Battery Storage Facilities, and Proposed Transmission Projects may satisfy the applicable
8 certification standards and are reasonably expected to serve the public convenience and
9 necessity and be in the public interest, and has appropriately addressed the Commission's
10 Large Load Guidelines.

11 **V. ACCOUNTING, RATEMAKING, SUSTAINABILITY AGREEMENT AND**
12 **OTHER RELATED ISSUES**

13 **A. ACCOUNTING AND RATEMAKING PRAYERS FOR RELIEF**

14 **Q141. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #10 RELATED TO THE**
15 **ESTABLISHMENT OF A REGULATORY LIABILITY FOR THE DEFERRAL**
16 **PROPOSAL.**

17 A. Prayer for Relief #10 requests that the Commission approve the establishment of a
18 regulatory liability for accounting purposes to support the Company's proposed Deferral
19 Proposal Framework. As explained by Mr. Dumas, the purpose of the proposed regulatory
20 liability is to better align the timing of the Customer revenues received during the ramp
21 period with the incremental revenue requirements associated with the Proposed Generators
22 as those facilities are ultimately placed into service. Without such a mechanism, the
23 Customer's revenues would initially produce significant reductions in FRPrates, followed
24 by corresponding increases as the associated generation and transmission investments

1 entered service. According to Mr. Dumas, the requested accounting treatment is intended
2 to avoid those unnecessary rate fluctuations and thereby promote greater rate stability for
3 ELL's other customers.¹⁶²

4 Because those revenues may remain deferred for a number of years before the
5 associated costs are incurred, ELL proposes that the regulatory liability accrue carrying
6 costs using the Company's approved weighted average cost of capital ("WACC"). Mr.
7 Dumas explains that this carrying cost is intended to preserve the time value of the deferred
8 revenues so that, when they are ultimately recognized, the regulatory liability more
9 appropriately offsets the associated revenue requirements.¹⁶³

10 Consistent with Company witness Ryan Jones' Deferral Proposal Framework, the
11 regulatory liability would not be recognized immediately in rates. Rather, once all of the
12 Proposed Generators have been placed into service, the deferred revenues would be
13 recognized over time to offset the incremental revenue requirements associated with those
14 facilities, thereby smoothing customer rate impacts that would otherwise occur.

15 In my opinion, the requested accounting treatment is conceptually reasonable and
16 I recommend that the Commission grant ELL's Prayer for Relief #10 related to the
17 establishment of a regulatory liability for the deferred revenues. As discussed earlier in
18 my testimony, I generally agree with the objective of avoiding unnecessary rate volatility
19 by better matching the timing of Customer revenues with the associated revenue
20 requirements. My remaining concerns relate not to the accounting treatment itself, but to
21 the assumptions embedded within the overall Deferral Proposal Framework and the

¹⁶² Direct Testimony of Ryan Dumas at 14-17.

¹⁶³ *Id.*

1 circumstances under which that framework may require future modification if the
2 Company's proposed supply plan or projected costs change materially. Those concerns
3 have been discussed previously in my testimony.

4 **Q142. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #11 RELATED TO THE**
5 **PROPOSED ACCOUNTING TREATMENT OF CIAC PAYMENTS RECEIVED**
6 **AND THE RECEIPT OF ANY TERMINATION FEE.**

7 A. I generally support the accounting treatments proposed by Company witness Ryan Dumas
8 for the Customer's various contributions under the ESA and CIAC Agreement. Mr. Dumas
9 explains that these accounting treatments are intended to appropriately recognize the
10 Customer's contributions based on the purpose for which they are made and to properly
11 match those contributions with the costs they are intended to offset.¹⁶⁴ In my opinion,
12 those proposed accounting treatments reasonably reflect the economic substance of the
13 transactions and are appropriate

14 I also generally agree with Mr. Dumas' proposal regarding the accounting treatment
15 of any future termination fee. [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 [REDACTED]

19 [REDACTED]

20 [REDACTED]

21 [REDACTED]

¹⁶⁴ Direct Testimony of Ryan Dumas at 6-11.

¹⁶⁵ *Id.* at 19-20.

1 [REDACTED]
2 [REDACTED]
3 I do, however, recommend one modification to the requested relief. In response to
4 Staff Data Request 1-144(a), ELL confirmed that it has not proposed a carrying charge
5 applicable to any termination-related deferred assets or liabilities.¹⁶⁶ In my opinion, [REDACTED]

6 [REDACTED]
7 [REDACTED]
8 [REDACTED]
9 [REDACTED]
10 [REDACTED]
11 [REDACTED]
12 [REDACTED]
13 [REDACTED]
14 [REDACTED].

15 Accordingly, I recommend that the Commission approve Prayer for Relief #11,
16 subject to the condition that [REDACTED]

17 [REDACTED]
18 [REDACTED].

19 **Q143. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #12 REQUESTING**
20 **AUTHORIZATION TO RECOVER THE RETAIL REVENUE REQUIREMENTS**
21 **ASSOCIATED WITH THE PROPOSED TRANSMISSION FACILITIES**

¹⁶⁶ RLS-013 (ELL Response to Staff 1-144).

1 **THROUGH THE FRP OR, ALTERNATIVELY, THROUGH THE CREATION OF**
2 **A REGULATORY ASSET.**

3 A. I generally support the ratemaking treatment requested by ELL in Prayer for Relief #12.
4 As discussed throughout my testimony, I conclude that the Proposed Transmission
5 Facilities satisfy the public convenience and necessity standard and should be certified,
6 subject to the conditions previously recommended. Once those facilities are placed in
7 service, it is appropriate for ELL to seek recovery of the agreed upon prudently incurred
8 costs associated with those facilities through its normal ratemaking mechanisms.

9 To the extent the FRP remains in effect when the Proposed Transmission Facilities
10 are placed in service, I believe recovery of agreed upon prudently incurred costs through
11 the FRP is appropriate and consistent with the manner in which transmission investments
12 have historically been reflected in retail rates. Should the FRP no longer be available, I
13 likewise believe it is reasonable to authorize ELL to establish a regulatory asset, with
14 carrying costs at the Company's approved WACC, until those costs can be incorporated
15 into rates through a subsequent base rate proceeding. This approach avoids unnecessary
16 regulatory lag while preserving the Commission's authority to review the prudence and
17 reasonableness of the costs before they are ultimately recovered from customers.

18 I do not interpret this requested relief as predetermining the amount of costs that
19 will ultimately be recoverable. Recovery should remain limited to the actual prudently
20 incurred costs associated with the Proposed Transmission Facilities, subject to all
21 applicable Commission review and approval. Likewise, I interpret the requested recovery
22 to be limited to the remaining retail revenue requirement after giving effect to any

1 Customer-funded contributions or other Customer revenues properly applicable to those
2 facilities so that customers are not required to pay twice for the same investment.

3 Accordingly, I recommend that the Commission approve Prayer for Relief #12 for
4 agreed upon prudently incurred costs.

5 **Q144. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #13 REQUESTING**
6 **AUTHORIZATION TO RECOVER THE RETAIL REVENUE REQUIREMENTS**
7 **ASSOCIATED WITH THE PROPOSED GENERATORS AND BATTERY**
8 **STORAGE FACILITIES THROUGH THE FRP OR, ALTERNATIVELY,**
9 **THROUGH THE REQUESTED DEFERRAL MECHANISM.**

10 A. I generally support the ratemaking treatment requested by ELL in Prayer for Relief #13.
11 As discussed throughout my testimony, I conclude that the Proposed Generators and
12 Battery Storage Facilities satisfy the applicable certification standards and should be
13 certified, subject to the conditions previously recommended. Once those facilities are
14 placed in service, it is appropriate for ELL to seek recovery of the agreed upon prudently
15 incurred costs associated with those facilities through its established ratemaking
16 mechanisms.

17 To the extent the FRP remains in effect when the Proposed Generators and Battery
18 Storage Facilities are placed in service, I believe recovery of the agreed upon prudently
19 incurred costs through the FRP, including the Additional Capacity Mechanism, is
20 appropriate and consistent with the purpose of that mechanism, which is to allow timely
21 recovery of qualifying generation investments placed into service between annual FRP
22 filings. Likewise, should the FRP no longer be in effect, I believe it is reasonable to
23 authorize the requested deferral of non-fuel revenue requirements, pre-operational plant

1 staffing costs, and the accrual of carrying charges at the Company's approved WACC until
2 those costs can be reflected in retail rates through a subsequent base rate proceeding. This
3 approach minimizes regulatory lag while preserving the Commission's authority to review
4 the prudence and reasonableness of the costs before they are ultimately recovered from
5 customers.

6 I likewise support ELL's proposal that recovery of those costs be subject to offset
7 by the deferred Customer revenues established under the Deferral Proposal Framework, as
8 previously discussed in my testimony. Offsetting the revenue requirements of the Proposed
9 Generators and Battery Storage Facilities by the deferred Customer revenues appropriately
10 recognizes that those Customer revenues are intended to mitigate the impact of those
11 investments on other retail customers during the Customer's load ramp-up period.

12 As with any future rate recovery, however, my recommendation is limited to the
13 actual prudently incurred costs associated with the Proposed Generators and Battery
14 Storage Facilities. Nothing in this recommendation should be interpreted as
15 predetermining the amount of costs ultimately recoverable or limiting the Commission's
16 continuing authority to review the prudence, reasonableness, and proper allocation of those
17 costs in future ratemaking proceedings.

18 Accordingly, I recommend that the Commission approve Prayer for Relief #13 for
19 agreed upon prudently incurred costs.

20 **Q145. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #14 REQUESTING**
21 **AUTHORIZATION TO RECOVER ANY DEFERRED BALANCES ASSOCIATED**

**WITH THE PROPOSED GENERATORS AND BATTERY STORAGE
FACILITIES OVER A TWO-YEAR PERIOD.**

A. I do not recommend that the Commission approve Prayer for Relief #14 as proposed. As discussed in my response to Prayer for Relief #13, I support authorizing ELL to defer the eligible non-fuel revenue requirements and other approved costs if the FRP is no longer in effect when the Proposed Generators or Battery Storage Facilities are placed into commercial operation. However, I do not believe the Commission should predetermine in this proceeding the amortization period that will ultimately apply to those deferred balances.

The appropriate amortization period should be determined in the future proceeding in which ELL first seeks to incorporate those deferred balances into retail rates. At that time, the Commission will have the benefit of a complete evidentiary record regarding the magnitude of the deferred balances, the length of time the balances were deferred, the resulting impact on customer rates, the Company's financial condition, and any other facts relevant to establishing a reasonable recovery period. Those facts cannot be known with certainty today.

By requesting approval now of a mandatory two-year recovery period, ELL is effectively asking this Commission to bind a future Commission before the relevant facts have developed. Setting aside whether the Commission can bind a future Commission in this manner, in my opinion, doing so would unnecessarily limit the Commission's future ratemaking discretion. While a two-year amortization period may ultimately prove to be reasonable, that determination should be made based on the facts and circumstances

1 existing at the time the deferred balances are first reflected in retail rates rather than being
2 predetermined in this certification proceeding.

3 Accordingly, I recommend that the Commission deny Prayer for Relief #14 without
4 prejudice to ELL requesting an appropriate amortization period in the future proceeding in
5 which recovery of the deferred balances is first sought.

6 **Q146. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #15 REQUESTING**
7 **APPROVAL OF THE PROPOSED DEPRECIABLE LIVES FOR THE PROPOSED**
8 **GENERATORS.**

9 A. ELL requests authorization to use a depreciable life of twenty (20) years for the four
10 Proposed Generators to be constructed in Richland Parish and a depreciable life of thirty-
11 two (32) years for the three Proposed Generators to be constructed in Pointe Coupee Parish.
12 I generally support this requested relief.

13 As discussed earlier in my testimony, the twenty-year depreciable life proposed for
14 the Richland Parish facilities appropriately reflects the unique circumstances of those units.
15 Those generators are being constructed specifically to serve the Customer's load under the
16 ESA, and the accelerated depreciation substantially reduces the potential for stranded
17 investment at the conclusion of the twenty-year contract term and prevents undesirable and
18 inequitable cost shifts. From a customer protection standpoint, that treatment is
19 appropriate, as opposed to extending depreciation beyond the contractual commitment.

20 Although there may be policy arguments supporting a shorter depreciable life for
21 the Pointe Coupee facilities as well, the information provided by ELL in this proceeding
22 supports ELL's proposal to depreciate those facilities over thirty-two years, the actual
23 projected life of the assets and current depreciation rate used by ELL for generation. In

1 light of my conclusion that ELL has demonstrated a need for the proposed generation
2 portfolio to serve Evest, that the overall proposal satisfies the applicable certification
3 standards, and the general practice to use the projected life of an asset for depreciation, the
4 information provided by ELL supports certification with the longer depreciable life for
5 those facilities.

6 Accordingly, I recommend that the Commission approve Prayer for Relief #15.

7 **Q147. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #16 REQUESTING**
8 **AUTHORIZATION TO ACCRUE A RETURN ON CERTAIN**
9 **INTERCONNECTION-RELATED COSTS INCURRED TO SECURE**
10 **INTERCONNECTION RIGHTS FOR THE PROPOSED GENERATORS.**

11 A. I generally support the relief requested in Prayer for Relief #16, subject to one important
12 understanding. I understand this request to apply only to those expenditures incurred to
13 secure interconnection rights that, [REDACTED]

14 [REDACTED]

15 [REDACTED].

16 As explained by Mr. Dumas, [REDACTED]

17 [REDACTED]

18 [REDACTED]

19 [REDACTED]

20 [REDACTED]

21 [REDACTED]

1 [REDACTED]
2 [REDACTED] 167

3 If my understanding is correct, I believe this treatment is reasonable because it
4 [REDACTED]
5 [REDACTED]
6 [REDACTED]
7 [REDACTED]
8 [REDACTED]
9 [REDACTED].

10 Accordingly, I recommend that the Commission approve Prayer for Relief #16,
11 provided that the requested carrying charge applies only during the period in which the
12 applicable interconnection-related costs are ineligible to accrue AFUDC or otherwise
13 recover financing costs, and that no duplicative return is permitted once those costs become
14 eligible for AFUDC or recovery through retail rates.

15 **Q148. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #17 REQUESTING**
16 **AUTHORIZATION TO RECOVER THE VARIABLE EXPENSES INCURRED**
17 **UNDER THE LONG-TERM SERVICE AGREEMENTS APPLICABLE TO THE**
18 **PROPOSED GENERATORS THROUGH THE FUEL ADJUSTMENT CLAUSE.**

19 A. I support ELL's request in Prayer for Relief #17. The Commission has previously
20 authorized recovery through the Fuel Adjustment Clause ("FAC") of the variable
21 components of long-term service agreements applicable to modern generating facilities. In
22 my opinion, continuing that treatment for the Proposed Generators is appropriate.

¹⁶⁷ Direct Testimony of Ryan Dumas at 11-13.

1 The variable expenses incurred under the Long-Term Service Agreements are
2 directly related to the operation of the generating units and vary with their use. As such,
3 they are appropriately treated as variable production costs rather than fixed costs associated
4 with the ownership of the facilities. Recovery through the FAC is therefore consistent with
5 the purpose of that mechanism, which is to recover prudently incurred variable costs
6 associated with providing electric service.

7 In addition, ELL's economic analyses and production cost modeling include these
8 variable Long-Term Service Agreement expenses as part of the operating costs of the
9 Proposed Generators. Accordingly, authorizing recovery of those costs through the FAC
10 is consistent with the assumptions underlying the analyses supporting the proposed projects
11 and avoids a mismatch between the costs reflected in those analyses and the costs
12 ultimately recoverable through rates.

13 Accordingly, I recommend that the Commission approve Prayer for Relief #17.

14 **Q149. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #18 REQUESTING**
15 **AUTHORIZATION TO CREDIT THE FUEL ADJUSTMENT CLAUSE WITH**
16 **THE REVENUES RECEIVED FROM THE CUSTOMER FOR ENERGY**
17 **PURCHASED DURING THE COMMISSIONING PERIOD.**

18 A. I support ELL's request in Prayer for Relief #18. During the Commissioning Period, [REDACTED]

19 [REDACTED]

20 [REDACTED]

21 [REDACTED]

22 [REDACTED]

23 [REDACTED]

1 Because the Fuel Adjustment Clause (“FAC”) is designed to recover the
2 Company’s prudently incurred variable energy costs, I believe it is appropriate that the
3 revenues ELL receives from the Customer for those energy purchases likewise be credited
4 through the FAC. Doing so ensures that retail customers receive the benefit of those
5 Customer payments and are not required to bear fuel costs that have already been recovered
6 from the Customer. Stated differently, the requested accounting treatment appropriately
7 matches the Customer revenues with the associated energy costs incurred during the
8 Commissioning Period and avoids the potential for double recovery.

9 Accordingly, I recommend that the Commission approve Prayer for Relief #18.

10 **Q150. PLEASE ADDRESS ELL’S PRAYER FOR RELIEF #3 REQUESTING THAT THE**
11 **PROPOSED GENERATORS AND BATTERY STORAGE FACILITIES BE**
12 **TREATED AS SYSTEM RESOURCES FOR THE BENEFIT OF ALL ELL**
13 **CUSTOMERS AND THAT THEIR FUEL COSTS BE ELIGIBLE FOR**
14 **RECOVERY THROUGH THE FUEL ADJUSTMENT CLAUSE.**

15 A. I support ELL’s request in Prayer for Relief #3. As discussed throughout my testimony,
16 the Proposed Generators and Battery Storage Facilities are being developed in response to
17 the Customer’s projected load and their annual costs are being directly assigned to Evest
18 through the MMC. Nevertheless, if the Commission grants certification then as requested
19 by ELL the Proposed Generators and Battery Storage Facilities once placed into
20 commercial operation should operate as part of ELL’s integrated generation portfolio for
21 the benefit of all retail customers. As system resources, they will be dispatched in
22 conjunction with the remainder of the Company’s generating fleet to economically serve
23 retail load, enhance system reliability, satisfy resource adequacy obligations, and produce

1 the production cost savings reflected in the Company's economic analyses. Those system-
2 wide benefits form an important part of the basis for my recommendation that the
3 Commission approve certification of the facilities.

4 Because the Proposed Generators and Battery Storage Facilities will function as
5 system resources, I likewise support recovery through the Fuel Adjustment Clause of the
6 prudently incurred fuel costs associated with operating the Proposed Generators and the
7 energy costs incurred to charge the Battery Storage Facilities. Recovery of those costs
8 through the FAC is consistent with the treatment of ELL's other generating resources and
9 is necessary to ensure that the fuel savings reflected in the Company's production cost
10 analyses are appropriately recognized in customer rates.

11 Accordingly, I recommend that the Commission approve Prayer for Relief #3 for
12 agreed upon prudently incurred costs.

13 **B. SUSTAINABILITY AGREEMENT PRAYERS FOR RELIEF**

14 **Q151. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #7 REQUESTING CERTAIN**
15 **FINDINGS REGARDING THE CUSTOMER'S ELIGIBILITY UNDER THE**
16 **COMMISSION'S 3GW ORDER AND RIDER GEAX ZERO.**

17 A. I do not recommend that the Commission approve Prayer for Relief No. 7. Although I
18 appreciate the Company's desire to obtain regulatory certainty regarding future
19 implementation of the Sustainability Agreement, I do not believe the requested findings
20 are necessary to resolve the issues presented in this proceeding.

21 This proceeding concerns the certification of the Proposed Generators, Battery
22 Storage Facilities, and Proposed Transmission Facilities necessary to serve the Customer's
23 anticipated load. The Sustainability Agreement contemplates that any Designated

1 Renewable Resources will be procured and presented to the Commission for approval in
2 future proceedings under the Commission's applicable renewable resource procurement
3 and certification processes. Company witness Elizabeth Ingram explains that the
4 Designated Renewable Resources will be subject to future certification under either the
5 expedited procedures established in the Commission's 3GW Order, if applicable, or the
6 Commission's traditional certification procedures. She further acknowledges that ELL has
7 separately requested amendments to the 3GW Order in Docket No. U-36697.¹⁶⁸

8 Prayer for Relief No. 7 asks the Commission to determine that the Customer
9 qualifies as a "New Customer," is eligible for a Group 3 Rider Geaux Zero subscription,
10 and may utilize the expedited procurement and certification procedures established under
11 the 3GW Order. In my opinion, those issues are governed by the Commission's orders and
12 tariffs applicable to Docket No. U-36697 and any subsequent amendments adopted in that
13 proceeding. They are not necessary to determine whether the facilities proposed in this
14 docket satisfy the applicable certification standards.

15 In addition, I do not believe this proceeding is the appropriate vehicle for the
16 Commission to approve or ratify provisions contained in the Sustainability Agreement. As
17 discussed earlier in my testimony, the Commission is not being asked to approve the
18 Electric Service Agreement, the Sustainability Agreement, or the contractual rights and
19 obligations negotiated between ELL and the Customer except to the limited extent specific
20 ratemaking or certification relief is otherwise requested and independently justified. While
21 the Sustainability Agreement forms part of the factual background supporting certain

¹⁶⁸ Direct Testimony of Elizabeth Ingram at 21; *see also* ELL Motion to Amend Order No. U-36697, Docket No. U-36697 (March 19, 2026).

1 aspects of the Application, the Commission's role in this proceeding is to determine
2 whether the requested certifications and other regulatory relief are appropriate—not to
3 approve or interpret the contractual provisions negotiated between the parties.
4 Accordingly, I do not believe the Commission should make findings concerning the
5 Customer's contractual rights or future eligibility under the Sustainability Agreement as
6 part of this proceeding

7 Moreover, because Docket No. U-36697 remains open and ELL has proposed
8 modifications to the procurement process, eligibility requirements, and expedited
9 certification framework, I believe any interpretations or clarifications regarding those
10 provisions should be addressed in that docket or in any future proceeding seeking approval
11 of specific Designated Renewable Resources. Addressing those issues here would
12 unnecessarily risk creating interpretations that could conflict with subsequent Commission
13 action in Docket No. U-36697.

14 Accordingly, I recommend that the Commission deny Prayer for Relief #7 without
15 prejudice to ELL seeking any necessary determinations regarding Rider Geaux Zero, the
16 3GW Order, or any successor procurement process in the proceedings specifically
17 established to administer those programs or in future proceedings involving the
18 certification of specific renewable resources.

19 **Q152. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #8 REQUESTING**
20 **APPROVAL OF THE PROPOSED PROTECTIONS AND DISPUTE**
21 **RESOLUTION PROCESS CONTAINED IN THE SUSTAINABILITY**

**AGREEMENT FOR DESIGNATED RENEWABLE RESOURCES THAT
EXCEED THE BREAK-EVEN PARAMETERS.**

A. I do not recommend that the Commission approve Prayer for Relief #8. My reasoning is substantially the same as that discussed in my response to Prayer for Relief #7.

The Commission is not being asked to approve the Electric Service Agreement, the Sustainability Agreement, or the contractual rights and obligations negotiated between ELL and the Customer. Rather, the Commission's responsibility in this docket is to determine whether the requested certifications and related regulatory relief should be granted. Accordingly, I do not believe it is appropriate for the Commission to approve or ratify contractual protections or dispute resolution procedures negotiated between the parties as part of the Sustainability Agreement.

Moreover, the protections and dispute resolution procedures described by Ms. Ingram relate to the future procurement, certification, and potential termination of Designated Renewable Resources under the Commission's 3GW Order and Rider Geaux Zero. Those matters are governed by the Commission's orders applicable to Docket No. U-36697, including any amendments that may ultimately be adopted, and by any future proceedings seeking approval of specific renewable resources. As such, I believe any questions regarding the appropriateness of those contractual provisions should be considered, if necessary, in those proceedings rather than in this certification docket.

Accordingly, I recommend that the Commission deny Prayer for Relief #8 without prejudice to ELL requesting approval of any appropriate procedures in future proceedings involving specific Designated Renewable Resources or in the proceedings governing the Commission's renewable resource procurement framework.

1 **Q153. PLEASE ADDRESS ELL'S PRAYER FOR RELIEF #9 REQUESTING**
2 **AUTHORIZATION FOR ELL TO TRANSFER TO, UTILIZE FOR THE BENEFIT**
3 **OF, OR RETIRE ON BEHALF OF THE CUSTOMER THE ALTERNATIVE**
4 **ENERGY CREDITS ("AECS") ASSOCIATED WITH CERTAIN CUSTOMER-**
5 **FUNDED NUCLEAR INVESTMENTS.**

6 A. Unlike my recommendations concerning Prayers for Relief #7 and #8, I recommend that
7 the Commission approve Prayer for Relief #9. My recommendation is not based on the
8 contractual provisions of the Sustainability Agreement itself, nor should it be interpreted
9 as approval of that agreement or its terms. Rather, my recommendation is based on the
10 appropriate regulatory treatment of the Alternative Energy Credits ("AECs") associated
11 with certain nuclear investments that are funded by the Customer.

12 As described by Ms. Ingram, the Customer has agreed to fund the Waterford 3
13 uprate, the Waterford 3 refueling cycle upgrades, and potentially other future nuclear
14 uprates, including a possible uprate at River Bend Station, in exchange for receiving the
15 AECs associated with the incremental generation resulting from those Customer-funded
16 investments. Importantly, however, Ms. Ingram expressly states that ELL is not seeking
17 certification or approval of the arrangements contained in the Sustainability Agreement
18 itself. Rather, the Company requests that the Commission acknowledge that the AECs
19 associated with those Customer-funded investments may be transferred to, utilized for the
20 benefit of, or retired on behalf of the Customer, provided the underlying investments are
21 approved by the Commission and otherwise receive any necessary regulatory approvals.¹⁶⁹

¹⁶⁹ Direct Testimony of Elizabeth Ingram at 9-12.

1 In my opinion, this request presents a ratemaking and regulatory allocation issue
2 rather than a request to approve a contractual provision of the Sustainability Agreement.
3 The Customer is proposing to fund the incremental investments that create the additional
4 environmental attributes associated with those projects. Under those circumstances, I
5 believe it is reasonable for the Customer to receive the associated AECs, provided the
6 underlying project is otherwise approved by the Commission and the Customer bears the
7 costs of the investment giving rise to those credits. This treatment is also consistent with
8 the Commission's prior treatment of renewable energy credits and other environmental
9 attributes associated with customer-funded investments.

10 Accordingly, I recommend that the Commission approve Prayer for Relief #9. My
11 recommendation should not be construed as approval of the Sustainability Agreement itself
12 or any other contractual rights or obligations between ELL and the Customer, but only as
13 an acknowledgement that the requested regulatory treatment of the AECs associated with
14 the identified Customer-funded nuclear investments is consistent with Commission policy.

15 **VI. CONCLUSION**

16 **Q154. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS TO**
17 **THE COMMISSION RELATED TO THE APPLICATION.**

18 A. My conclusions and recommendations are summarized as follows:

- 19 1. **Lightning Initiative (Prayer for Relief 5).** I conclude that ELL has satisfied the
20 procedural requirements necessary to qualify for the Commission's Lightning Initiative
21 waiver. Accordingly, I recommend that the Commission grant the requested waiver of
22 the MBM requirements. That recommendation relates only to the procedural waiver

1 authorized by the Lightning Initiative and should not be interpreted as a
2 recommendation that the requested certifications or other relief be granted.

3 **2. Historical Footprint Order (Prayer For Relief 4).** I conclude that ELL has complied
4 with the requirements of Rule 3 of the Commission's Historical Footprint Order
5 applicable to load additions exceeding five percent (5%) of the utility's prior peak load.
6 Specifically, ELL satisfied the rule by filing this proceeding pursuant to the
7 Commission's 1983 Capacity Certification Order seeking certification of the
8 generation resources necessary to serve the projected increase in load. Accordingly, I
9 recommend that the Commission find that ELL has complied with Rule 3 of the
10 Historical Footprint Order.

11 **3. Generation and Transmission Certifications (Prayers for Relief 1, 2 and 6).**
12 Subject to conditions, I conclude that ELL has demonstrated that the Proposed
13 Generators, Battery Storage Facilities, and Proposed Transmission Facilities can satisfy
14 the applicable certification standards, has appropriately addressed the Commission's
15 Large Load Guidelines, and that the proposed investment can reasonably be expected
16 to serve the public convenience and necessity and be in the public interest. In
17 accordance with the forgoing, I recommend that the Commission can grant the
18 requested certifications subject to the following conditions:

19 a. Continuing Responsibility for the Customer Agreements. The Commission's
20 certification should not constitute approval of the Customer Agreements or a
21 determination that those agreements adequately protect existing customers under
22 every future circumstance. ELL should remain fully responsible for negotiating,
23 implementing, administering, enforcing, and, where necessary, modifying the

1 Customer Agreements. Nothing in the Commission's Order should limit the
2 Commission's authority to review those agreements or determine the appropriate
3 allocation of any resulting costs or damages in future proceedings. In addition,
4 because the requested certifications are based upon the Customer Agreements
5 presented in this proceeding, those agreements should not be materially modified
6 without prior notice to the Commission.

7 b. Continuing Responsibility for Project Implementation. The certifications should
8 be limited to the Proposed Generators, Battery Storage Facilities, and Proposed
9 Transmission Facilities identified in this proceeding and should not constitute
10 approval of future operational decisions, future modifications to the Customer
11 Agreements, future changes to the proposed supply plan, or implementation of the
12 Customer's ramp schedule. ELL should remain responsible for prudently
13 managing Project Evest as changing circumstances require.

14 c. Operational Condition Prior to Full Firm Service. Prior to commencement of full
15 firm service, ELL should submit for Commission approval a comprehensive
16 operational control and emergency load shed plan governing the integration of
17 Project Evest into ELL's emergency operating procedures

18 d. Ratemaking Condition Related to Ramp Period. ELL should submit for
19 Commission approval an appropriate ratemaking mechanism deferring the recovery
20 of any material capacity costs to be incurred during the Customer's ramp period
21 that would be included in customer rates so that those costs are reasonably aligned
22 with the long-term benefits expected from Project Evest.

- 1 e. Reservation of Future Ratemaking Authority. Nothing in the Commission's Order
2 should be interpreted as predetermining the future ratemaking treatment of stranded
3 assets, changes to the proposed supply plan, future construction costs,
4 implementation of the Customer Agreements, or any future request for recovery of
5 costs associated with Project Evest. Those matters should remain subject to the
6 Commission's continuing jurisdiction.
- 7 f. Existing Ratemaking Mechanisms and Rider Conformance. Prior to the
8 Commission acting on this Application, ELL should identify any existing
9 Commission-approved riders, allocators, cost recovery mechanisms, or other rate
10 design provisions materially affected by Project Evest, including but not limited to
11 the Resilience and Storm Riders, and file one or more proposed solutions sufficient
12 to ensure that such mechanisms continue to operate in a manner consistent with
13 their intended purpose, avoid over- or under-collections, and equitably allocate
14 costs and benefits among customer classes. The Commission may, in its discretion,
15 resolve those issues in this proceeding, condition certification upon implementation
16 of an approved solution, or require ELL to address them in one or more subsequent
17 proceedings before the affected mechanisms are applied to Project Evest.
- 18 g. Non-Renewal and Transition Reporting. ELL should keep the Commission
19 informed regarding the status of the Customer Agreements and promptly notify the
20 Commission of any notice of non-renewal or other material change affecting
21 continuation of service. Within six months of receiving a notice of non-renewal,
22 ELL should file a comprehensive transition plan addressing the disposition of the
23 generation and transmission assets associated with Project Evest, proposed

1 mitigation of any stranded investment, continued utilization or monetization of the
2 facilities, and any proposed ratemaking treatment.

3 If the Commission were to grant ELL's requested Certifications for the generation
4 and transmission needed to serve Project Evest, I recommend the following conditions
5 related to the remainder of ELL's prayers for relief:

6 4. **Deferred Revenue Regulatory Liability (Prayer for Relief 10).** I recommend
7 that the Commission approve ELL's proposed deferred revenue regulatory liability
8 and associated accounting treatment supporting the Deferral Proposal Framework.

9 5. **Customer Contributions and Termination Fees (Prayer for Relief 11).** I
10 recommend that the Commission approve ELL's proposed accounting treatment
11 for Customer CAIC and any potential termination fees, subject to the additional
12 requirement that any termination fee retained in a regulatory liability should accrue
13 a carrying charge at Company's WACC until the Commission determines the
14 ultimate disposition of those funds.

15 6. **Transmission Cost Recovery (Prayer for Relief 12).** I recommend that the
16 Commission approve recovery of the agreed-upon prudently incurred retail revenue
17 requirements associated with the Proposed Transmission Facilities through the FRP
18 or, if necessary, an appropriate regulatory asset, subject to future Commission
19 review of prudence and reasonableness.

20 7. **Generation and Battery Cost Recovery Prayer for Relief 13).** I recommend that
21 the Commission approve recovery of the agreed-upon prudently incurred retail
22 revenue requirements associated with the Proposed Generators and Battery Storage

Facilities through the FRP or, if necessary, the proposed deferral mechanism, subject to future Commission review of prudence and reasonableness.

8. **Deferred Balance Amortization (Prayer for Relief 14).** I do not recommend that the Commission predetermine a two-year amortization period for any future deferred balances of the Proposed Generators and Battery Storage. I recommend that the appropriate amortization period be determined in the future proceeding in which it is determined that those balances are to be first reflected in retail rates.
9. **Depreciation Lives (Prayer for Relief 15).** I recommend that the Commission approve the proposed depreciable lives of 20 years for the Richland generating facilities and 32 years for the Pointe Coupee generating facilities.
10. **Interconnection Rights (Prayer for Relief 16).** I recommend that the Commission approve the requested carrying charge for qualifying interconnection-right costs as understood and explained in my testimony above only to the extent those costs are temporarily ineligible for AFUDC or other financing recovery, and provide no duplicative financing recovery is permitted.
11. **Long-Term Service Agreements (Prayer for Relief 17).** Consistent with Commission practice, I recommend that the Commission approve recovery through the Fuel Adjustment Clause of the variable expenses associated with the Long-Term Service Agreements applicable to the Proposed Generators.
12. **Commissioning Period Fuel Revenues Prayer for Relief 18).** I recommend that the Commission approve crediting to the Fuel Adjustment Clause the revenues received from the Customer for energy purchased during the Commissioning Period.

- 1 13. **System Resource Treatment (Prayer for Relief 3).** I find that the Proposed
2 Generators and Battery Storage Facilities are being developed in response to the
3 Customer's projected load and their annual costs is proposed to be direct assigned
4 to Evest through the MMC Nevertheless, I recommend that the Commission
5 approve treatment of the Proposed Generators and Battery Storage Facilities as
6 system resources for the benefit of all ELL customers and approve recovery of their
7 prudently incurred fuel costs through the Fuel Adjustment Clause.
- 8 14. **Sustainability Agreement – 3GW eligibility (Prayer for Relief 7).** I do not
9 recommend that the Commission grant the relief requested in Prayer for Relief No.
10 7 regarding the Customer's eligibility under the Commission's 3GW Order and
11 Rider Geaux Zero and use of an expedited certification proceeding. The
12 Commission does not need to determine in this proceeding seeking certification of
13 generation and transmission to serve Project Evest to approve or interpret the
14 Sustainability Agreement or the contractual rights and obligations negotiated
15 between ELL and the Customer as they relate to Rider Geaux Zero. Moreover, the
16 requested findings concern the implementation and interpretation of the
17 Commission's 3GW Order and Rider Geaux Zero, issues that are more
18 appropriately addressed in Docket No. U-36697 or in future proceedings involving
19 the procurement and certification of specific renewable resources.
- 20 15. **Sustainability Agreement-Protections and Dispute Resolution Approval**
21 **(Prayer for Relief 8).** I do not recommend that the Commission grant the relief
22 requested in Prayer for Relief No. 8 seeking approval of the proposed protections
23 and dispute resolution procedures contained in the Sustainability Agreement related

1 to potential resources above a breakeven parameter. Unlike the ratemaking and
2 certification issues presented elsewhere in this proceeding, this request asks the
3 Commission to approve contractual provisions contained within the Sustainability
4 Agreement itself. Because I do not recommend that the Commission approve or
5 ratify the Sustainability Agreement as part of this proceeding, I likewise do not
6 recommend approval of the contractual dispute resolution process contained within
7 that agreement

8 16. **Alternative Energy Credits (Prayer for Relief 9).** I recommend that the
9 Commission approve the requested regulatory treatment of Alternative Energy
10 Credits associated with Customer-funded nuclear uprates identified in the
11 Application. This recommendation is based upon the appropriate regulatory
12 allocation of environmental attributes associated with Customer-funded
13 investments and should not be construed as approval of the Sustainability
14 Agreement or any of its contractual provisions.

15 17. **Future Regulatory Authority.** Finally, I recommend that the Commission
16 expressly provide that nothing in its Order approving the requested certifications or
17 other relief should be interpreted as predetermining the future ratemaking treatment
18 of stranded assets, changes to the proposed supply plan, future construction costs,
19 future amendments to the Customer Agreements, or any future request for cost
20 recovery. Those matters necessarily depend upon facts and circumstances that do
21 not presently exist and should remain subject to the Commission's continuing
22 regulatory authority.

1 **Q155. HAVE YOU ATTEMPTED TO ADDRESS EVERY ISSUE PRESENTED BY ELL'S**
2 **APPLICATION?**

3 A. No. The issues discussed in my testimony are those that I believe are most relevant to the
4 Commission's evaluation of the Application and those for which I believe additional
5 discussion would be helpful to represent the positions I have taken herein. Given the
6 breadth of the Application, supporting testimony, exhibits, discovery responses, and related
7 proceedings, it would be impractical to address every issue raised by ELL's Application.

8 **Q156. DOES YOUR FAILURE TO DISCUSS A PARTICULAR ISSUE, ASSUMPTION,**
9 **ANALYSIS, OR REPRESENTATION MADE BY ELL INDICATE THAT YOU**
10 **AGREE WITH IT OR THAT YOU BELIEVE IT HAS BEEN PROVEN?**

11 A. No. My decision not to address a particular issue should not be interpreted as agreement
12 with, acceptance of, or endorsement of any specific assumption, analysis, conclusion,
13 representation, or recommendation made by ELL or any other party. Nor should it be
14 interpreted as a determination that such matter has been proven or resolved. Rather, my
15 testimony focuses on the issues that I believe warrant particular attention by the
16 Commission in this proceeding. Moving forward, the Commission Staff reserves all rights
17 to address any concerns herein addressed, or otherwise, related to the Application through
18 its continued consideration in this docket.

19 **Q157. DOES THIS CONCLUDE YOUR TESTIMONY?**

20 A. Yes.
21

BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION
ENTERGY LOUISIANA, LLC, EX PARTE.

In re: Application of Entergy Louisiana,
LLC for Certification of Generation and
Transmission Resources and for Other
Relief Pursuant to the Commission's
Lighting Initiative

DOCKET NO. U-37882



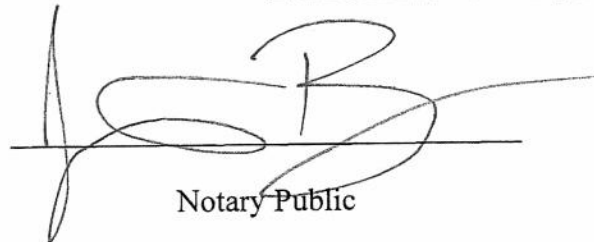
AFFIDAVIT

R. Lane Sisung, being first duly sworn, deposes and says: that he is the same R. Lane Sisung whose Direct Testimony accompanies this affidavit; that Direct Testimony was prepared by him or under his direct supervision and control; that he is familiar with the contents thereof; that the facts and opinions set forth therein are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as his sworn Direct Testimony in this proceeding.



R. Lane Sisung

Subscribed and sworn before me on this 23 day of July, 2026.



Notary Public

My Commission Expires: at death

**Service List for U-37882
as of 7/31/2026**

Commissioner(s)

Jean-Paul P. Coussan

Mike Francis

Davante Lewis

Foster L. Campbell

Eric Skrmetta

LPSC Staff Counsel

Lauren Evans, Deputy General Counsel

LPSC Staff

Donnie Marks, LPSC Utilities Division

Robin Pendergrass, LPSC Auditing Division

LPSC Consultant

R. Lane Sisung
United Professionals Company
3850 North Causeway Blvd., Suite 1930
Metairie, LA 70002
Email: lane@sisung.com
Fax: (504)544-7701; Phone: (504)544-7724

Julie Viviano
United Professionals Company
3850 North Causeway Blvd., Suite 1930
Metairie, LA 70002
Email: julie@sisung.com
Fax: (504)544-7701; Phone: (504)544-7711

Jake Chapman
United Professionals Company
3850 North Causeway Blvd., Suite 1930
Metairie, LA 70002
Email: jake@sisung.com
Fax: (504)544-7730; Phone: (504)544-7701

Jonathan Bourg
United Professionals Company
3850 North Causeway Blvd., Suite 1930
Metairie, LA 70002
Email: jbourg@sisung.com
Fax: (504)544-7702; Phone: (504)544-7728

LPSC Special Counsel

Dana Shelton

FishmanHaygood LLP

201 St. Charles Avenue, 46th Floor

New Orleans, LA 70170

Email: dshelton@fishmanhaygood.com

Fax: ; Phone: (504)556-5252

Noel Darce

FishmanHaygood LLP

201 St. Charles Avenue, 46th Floor

New Orleans, LA 70170

Email: ndarce@fishmanhaygood.com

Fax: ; Phone: (504)556-5252

Justin A. Swaim

FishmanHaygood LLP

201 St. Charles Avenue, 46th Floor

New Orleans, LA 70170

Email: jswaim@fishmanhaygood.com

Fax: ; Phone: (504)556-5252

Applicant :

Entergy Louisiana, LLC

Lawrence J. Hand Jr.

Entergy Louisiana, LLC

4809 Jefferson Highway

Mail Unit L-JEF-357

Jefferson, LA 70121

Email: lhand@entergy.com

Fax: (504)840-2681; Phone: (504)840-2528

Ryan D. Jones
Entergy Services, LLC
4809 Jefferson Highway
Main Unit L-JEF-357
Jefferson, LA 70121
Email: rjone25@entergy.com
Fax: (504)840-2681; Phone: (504)840-2615

D. Skylar Rosenbloom
Entergy Services, LLC
639 Loyola Avenue
Mail Unit L-ENT-26E
New Orleans, LA 70113
Email: drosenb@entergy.com
Fax: (504)579-5579; Phone: (504)576-2603

Matthew T. Brown
Entergy Services, LLC
639 Loyola Avenue
Mail Unit L-ENT-26E
New Orleans, LA 70113
Email: mbrow12@entergy.com
Fax: (504)576-5579; Phone: (504)576-4645

Michael R. Dodson
Entergy Services, LLC
639 Loyola Avenue
Mail Unit L-ENT-26E
New Orleans, LA 70113
Email: mdodso1@entergy.com
Fax: ; Phone: (504)576-5508

Intervenor :

Louisiana Energy Users Group

Randy Young

Kean Miller, LLP

400 Convention Street, Suite 700 (70802)

Post Office Box 3513

Baton Rouge, LA 70821-3513

Email: Randy.Young@keanmiller.com

Fax: (225)388-9133; Phone: (225)387-0999

Carrie R. Tournillon

Kean Miller, LLP

400 Convention Street, Suite 700 (70802)

Post Office Box 3513

Baton Rouge, LA 70821-3513

Email: carrie.tournillon@keanmiller.com

Fax: (504)585-3051; Phone: (504)585-3056

Gordon D. Polozola

Kean Miller, LLP

400 Convention Street, Suite 700 (70802)

Post Office Box 3513

Baton Rouge, LA 70821-3513

Email: gordon.polozola@keanmiller.com

Fax: (225)388-9133; Phone: (225)387-0999

Intervenor :

Alliance for Affordable Energy

Alaina DiLaura

Alliance for Affordable Energy

4505 S. Claiborne Ave.

New Orleans, LA 70125

Email: alaina@all4energy.org

Fax: ; Phone: (504)208-9761

Logan Atkinson Burke

Alliance for Affordable Energy

4505 S. Claiborne Avenue

New Orleans, LA 70125

Email: Logan@all4energy.org

Fax: (504)313-3478; Phone: (504)208-9761

Sophie Zaken

Alliance for Affordable Energy

4505 S. Claiborne Avenue

New Orleans, LA 70125

Email: regulatory@all4energy.org

Fax: (504)313-3478; Phone: (504)208-9761

Intervenor :

Southern Renewable Energy Association

Simon Mahan

Southern Renewable Energy Association (SREA)

11610 Pleasant Ridge Road, Suite 103 #176

Little Rock, AR 72223

Email: simon@southernwind.org

Fax: ; Phone: (337)303-3723

Whit Cox

Southern Renewable Energy Association (SREA)

11610 Pleasant Ridge Road, Suite 103 #176

Little Rock, AR 72223

Email: whit@southernrenewable.org

Fax: ; Phone: (501)701-0874

Harry J Vorhoff

Plauche & Carr LLP

450 Laurel Street, Ste. 1850

Baton Rouge, LA 70801

Email: Harry@plauchecarr.com

Fax: ; Phone: (225)256-4028

Megan K. Terrell

Plauche & Carr LLP

450 Laurel Street, Ste. 1850

Baton Rouge, LA 70801

Email: Megan@plauchecarr.com

Fax: ; Phone: (225)256-4028

Intervenor : Union of Concerned Scientists

Paul Arbaje
Union of Concerned Scientists
200 East Randolph Street
Suite 5151
Chicago, IL 60601
Email: parbaje@ucs.org
Fax: ; Phone: (617)716-6314

Sam Gomberg
Union of Concerned Scientists
1825 K St. NW
Suite 800
Washington, DC 20006
Email: sgomberg@ucs.org
Fax: ; Phone: (202)331-6953

Jeff Deyette
Union of Concerned Scientists
2 Brattle Square
Cambridge, MA 02138
Email: jdeyette@ucs.org
Fax: ; Phone: (617)301-8012

Intervenor : Sierra Club

Joshua Smith
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, CA 94612-3011
Email: joshua.smith@sierraclub.org
Fax: (510)208-3140; Phone: (415)977-5560

Kristin Henry
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612
Email: kristin.henry@sierraclub.org
Fax: (415)977-5793; Phone: (415)977-5560

Tony Mendoza
Sierra Club Environmental Law Program
2101 Weber Street, Suite 1300
Oakland, CA 94612
Email: tony.mendoza@sierraclub.org
Fax: ; Phone: (415)977-5589

Ashley Soliman
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, CA 94612-3011
Email: ashley.soliman@sierraclub.org
Fax: ; Phone: (415)977-5660

Soliana Samson
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, CA 94612
Email: soliana.samson@sierraclub.org
Fax: ; Phone: (805)253-3479*

Intervenor :

**Association of Louisiana Electric
Cooperatives, Inc. (ALEC)**

Kyle C. Marionneaux

Marionneaux Kantrow, LLC

10202 Jefferson Highway, Building C

Baton Rouge, LA 70809

Email: kyle@mklawla.com

Fax: (225)757-1709; Phone: (225)769-7473

Kara B. Kantrow

Marionneaux Kantrow, LLC

10202 Jefferson Highway, Building C

Baton Rouge, LA 70809-3183

Email: kara@mklawla.com

Fax: (225)757-1709; Phone: (225)769-7473

H. Barlow Holley

Marionneaux Kantrow, LLC

10202 Jefferson Highway, Building C

Baton Rouge, LA 70809

Email: barlow@mklawla.com

Fax: (225)757-1709; Phone: (225)769-7473

Intervenor :

1803 Electric Cooperative, Inc.

Kyle C. Marionneaux

Marionneaux Kantrow, LLC

10202 Jefferson Highway, Building C

Baton Rouge, LA 70809

Email: kyle@mklawla.com

Fax: (225)757-1709; Phone: (225)769-7473

Ron Repsher

1803 Electric Cooperative, Inc.

4601 Bluebonnet Blvd.

Baton Rouge, LA 70809

Email: ron.repsher@1803electric.coop

Fax: ; Phone: (405)831-5615

John N. Grinton

1803 Electric Cooperative, Inc.

4601 Bluebonnet Blvd.

Baton Rouge, LA 70809

Email: john.grinton@1803electric.coop

Fax: ; Phone: (225)457-1803

Intervenor :

Walmart Inc.

Carrie H. Grundmann

Spilman Thomas & Battle, PLLC

110 Oakwood Drive, Suite 500

Winston-Salem, NC 27103

Email: cgrundmann@spilmanlaw.com

Fax: (336)725-4476; Phone: (540)353-2744

Steve W. Chriss

Walmart Inc.

2608 SE J Street, Mail Stop: 5530

Bentonville, AR 72716

Email: stephen.chriss@walmart.com

Fax: ; Phone: (479)204-1594

Derrick P. Williamson

Spilman Thomas & Battle, PLLC

1100 Bent Creek Blvd, Suite 101

Mechanicsburg, PA 17050

Email: dwilliamson@spilmanlaw.com

Fax: (717)795-2743; Phone: (717)795-2741

Intervenor :

**Alliance for Affordable Energy and Union
of Concerned Scientists**

Susan Stevens Miller

Earthjustice

1001 G Street NW, Suite 1000

Washington, DC 20001

Email: smiller@earthjustice.org

Fax: (202)667-2356; Phone: (202)797-5246

Sameer Doshi

Earthjustice

311 S. Wacker Dr., Suite 1400

Chicago, IL 60606

Email: sdoshi@earthjustice.org

Fax: ; Phone: (312)800-8332

Intervenor :

**Gulf States Renewable Energy Industry
Association**

Monika Gerhart

400 Poydras Street, Suite 900

New Orleans, LA 70130

Email: mgerhart@gsreia.org

Stephen Wright

400 Poydras St, Suite 900

New Orleans, LA 70130

Email: swright@gsreia.org

Fax: ; Phone: (504)383-8936